Consideration of Comments — 1st Draft of TPL-001-1 — Transmission System Planning Performance Requirements

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the first draft of the standard. This standard was posted for a 30-day public comment period from September 12, 2007 through October 26, 2007. The drafting team asked stakeholders to provide feedback on the standard through a special Standard Comment Form. There were more than 80 sets of comments, including comments from 236 different people from more than 80 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

Based on the comments received, the drafting team is recommending a second posting of the revised standard.

Definitions and the following requirements have been changed due to industry comment as specifically cited in the responses:

Definitions

- Base Case - the SDT removed "Base Case" as a defined term.
- Bus-tie Breaker – the SDT added a definition.
- Consequential Load Loss – the SDT reworded the definition to better clarify that this is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied and to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load.
- Extreme Events – the SDT revised the definition to clarify that Extreme Events have a "lower probability of occurrence than Planning Events."
- Long-Term Transmission Planning Horizon - the SDT revised the definition to clarify when the horizon may extend beyond ten years
- Non-Consequential Load Loss - the SDT revised the definition to improve its clarity and to specify that this is non-interruptible load
- Planning Assessment - the SDT revised the definition to be more succinct, to eliminate the description of the possible range of assumptions, and to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.
- Planning Coordinator – the SDT added the definition from the Functional Model.
- Plant Stability Study - the SDT replaced the word, "plant" with the term, "generating unit," and modified the wording to improve its clarity.
- System Stability Study - the SDT revised the definition to add further clarity
- Year One - the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study, and to clarify that the planning window begins 12 to 18 months from the completion of the previous assessment.

Sensitivity Studies

The need to conduct sensitivity studies was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The revised standard provides guidance on what needs to be included in sensitivity studies while not being totally prescriptive.

- Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.
- Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.
- Requirement R2.4.3 was modified to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.
- Requirement R.2.4.3.2 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.2 (related to steady state analysis) "Modification of expected transfers"
- Requirement R.2.4.3.4 (related to stability analysis) was changed to use the same phrase as used in R.2.1.3.4 (related to steady state analysis) "Variability and outages of reactive resources."
- A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Corrective Action Plans

Requirements for corrective action plans have been modified to clarify that these do not need to be developed solely to meet performance requirements for sensitivities and to eliminate subrequirements that distinguished between "committed" and "proposed" projects. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between "committed" and "proposed" projects. The following adjustments were made to the list of elements that must be included in Corrective Action Plans:

- Sub-requirement R2.7.1 was modified to clarify that there are many options that can be used to achieve required system performance when studies show system deficiencies, including DSM.
- Sub-requirement R2.7.2 to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.
- Sub-requirement R2.7.3 to document the criteria for determining committed and proposed projects and to identify each project as either committed or proposed has been deleted.
- Sub-requirement R2.7.4 that included language restricting the removal of committed projects has been deleted.

- A new Sub-requirement R2.7.2 has been added that requires a description of the consideration of sensitivity studies was applied to the actions needed to achieve system performance

Performance Requirements

- The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.
- The second draft proposes that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event.
- The second draft proposes permitting the loss of Non-Consequential Load to meet the Transmission performance requirements for events where there are two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. (See Performance Table Planning Event P6.)
- The second draft proposes allowing load shedding as an acceptable system adjustment action for the entire BES following the loss of the second Transmission outage.
- Moved P2-3 into the P1 category as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
- Clarified the distinction between Generating Unit Stability Study and System Stability Study by adding a definition of Generating Unit Stability Study and modifying the definition of System Stability Study – and making modifications to R2.5.
- Removed Extreme Event #9 from Stability Analyses for Extreme Events (3-phase fault and loss of all generating units at a station). The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.
- Modified R2.4.1 to recognize the difficulty of obtaining accurate dynamic Load models including induction motors.
- Modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

Generation Run Back and Tripping

- Added R3.5.2 and R3.5.3 to clarify that manual or automatic generation run-back is allowed as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.
- Modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.
- Modified R3.5 to allow the use of SPS/RAS for single or multiple Contingencies with limitations described in Requirements R3.5.1 through R3.5.3.

Modeling

- A new requirement was added (to replace R1.4) to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.

- In addition, both performance tables have been changed.

Some other major changes included:

- Created a new requirement concerning short circuit analysis.
- Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding.
- Changed requirements to clarify the actions allowed to prepare for the next Contingency.
- Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations

In this "Consideration of Comments" document stakeholder comments have been organized so that it is easier to see the responses associated with each question. All comments received on the standards can be viewed in their original format at:

http://www.nerc.com/~filez/standards/Assess-Transmission-Future-Needs.html

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 Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

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

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1.	William Quaintance	ABB Grid Systems Consulting										
2.	John Bussman	AECI	✓									
3.	Anita Lee	AESO		✓								
4.	Darrell Pace (G11)	Alabama Electric Coooperative	✓									
5.	Wesley O. Davis	Alcoa Power Generating, Inc.	✓		✓		✓		✓			
6.	William J. Smith	Allegheny Power	✓									
7.	Ken Goldsmith (G9)	ALTW										
8.	Rick Foster (G12)	Ameren										
9.	John Sullivan (G11)	Ameren	✓									
10.	Curtis Stepanek (G14)	Ameren	✓									
11.	Eugene Warnecke (G14)	Ameren	✓									
12.	John E. Sullivan	Ameren Services	✓									
13.	Thad K. Ness (G2)	American Electric Power	✓		✓		✓	✓				
14.	Takis Laios (G2)	American Electric Power	✓									
15.	Jon Riley (G2)	American Electric Power	✓									
16.	Rob O'Keefe (G2)	American Electric Power	✓									
17.	Navin Bhatt (G2)	American Electric Power	✓									
18.	Scott Rainbolt (G2)	American Electric Power	✓									
19.	Omar Hellalat (G2)	American Electric Power	✓									
20.	Roger Bentz (G2)	American Electric Power	✓									
21.	Vance Beauregard (G2)	American Electric Power	✓									
22.	Phil Cox (G2)	American Electric Power					✓	✓				
23.	E. Nick Henery (G4)	APPA			✓	✓						
24.	Allen Mosher (G4)	APPA			✓	✓						
25.	Baj Agrawal	Arizona Public Service Co.	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
26.	Jason Shaver	ATC	✓									
27.	Phil Park	BCTC		✓								
28.	Dave Rudolph (G9)	BEPC										
29.	Chris Bradley (G14)	Big Rivers Electric Corporation	✓									
30.	Chuck Matthews (G3)	BPA Transmission	✓									
31.	Berhanu Tesema (G3)	BPA Transmission	✓									
32.	Kendall Rydell (G3)	BPA Transmission	✓									
33.	Kyle Kohne (G3)	BPA Transmission	✓									
34.	Melvin Rodrigues (G3)	BPA Transmission	✓									
35.	David Albers	Brazos Electric Cooperative	✓									
36.	Charles Cumpton	California ISO		✓								
37.	Paul Rocha (see attachment)	CenterPoint Energy	✓									
38.	David M Conroy (see attachment)	Central Maine Power Company	✓									
39.	Gary Brinkworth (G7)	City of Tallahassee	✓									
40.	Jeff Knottek	City Utilities/Springfield	✓		✓							
41.	Karl Kohlrus (G8)	City Water, Light & Power (IL)					✓					
42.	Karl E. Kohlrus	City Water, Light and Power			✓	✓	✓					
43.	Edwin Thompson (G10)	ConEd										
44.	Michael Gildea (G10)	Constellation Energy										
45.	Blake Williams	CPS Energy	✓									
46.	John K. Loftis, Jr. (G1)	Dominion VA Power	✓									
47.	Kirit Doshi (G1)	Dominion VA Power	✓									
48.	Graig Crider (G1)	Dominion VA Power	✓									
49.	Solomon Yirga (G1)	Dominion VA Power	✓									
50.	Nelson Burks (G1)	Dominion VA Power	✓									
51.	Ashwani Vaswani (G1)	Dominion VA Power	✓									
52.	Mehdi Shakibafar (G1)	Dominion VA Power	✓									
53.	Abdur Masood (G1)	Dominion VA Power	✓									
54.	Thanh Nguyen (G1)	Dominion VA Power	✓									
55.	Ed Broasdale (G1)	Dominion VA Power	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Al MacDonald (G1)	Dominion VA Power	✓									
57.	William Bigdely (G1)	Dominion VA Power	✓									
58.	Ronnie Bailey (G1)	Dominion VA Power	✓									
59.	Greg Rowland	Duke Energy	✓		✓							
60.	Anthony Williams (G12)	Duke Energy Carolinas										
61.	Brian D. Moss (G14)	Duke Energy Carolinas	✓									
62.	Keith Yocum	E ON US										
63.	Larry Rodriguez	Entegra Power					✓	✓				
64.	Sujit Mandal (G12)	Entergy										
65.	Charles Long (G11)	Entergy	✓									
66.	Kham Vongkhamchanh (G14)	Entergy	✓									
67.	Charles W. Long	Entergy Services, Inc.	✓		✓		✓					
68.	Doug Powell	Entergy Services, Inc.	✓		✓		✓					
69.	H. Steven Myers	ERCOT ISO		✓								
70.	Eric Mortenson	Exelon	✓		✓							
71.	Doug Hohlbaugh (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
72.	John Stephens (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
73.	Dave Folk (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
74.	Sam Ciccone (G5)	FirstEnergy Corporation	✓		✓		✓	✓				
75.	W. R. Schoneck (G7)	Florida Power & Light Company			✓							
76.	C. Martin Mennes (G7)	Florida Power & Light Company	✓									
77.	Robert A. Birch (G7)	Florida Power & Light Company					✓					
78.	John W. Shaffer (G7)	Florida Power & Light Company			✓							
79.	A. L. Barredo (G7)	Florida Power & Light Company			✓							
80.	Hector Sanchez (G6)	Florida Power and Light	✓		✓		✓					
81.	Marty Mennes (G6)	Florida Power and Light	✓		✓		✓					
82.	W. R. Schoneck (G6)	Florida Power and Light	✓		✓		✓					
83.	R. A. Birch (G6)	Florida Power and Light	✓		✓		✓					
84.	A. L. Barredo (G6)	Florida Power and Light	✓		✓		✓					
85.	C. Candelaria (G6)	Florida Power and Light	✓		✓		✓					
86.	J. W. Shaffer (G6)	Florida Power and Light	✓		✓		✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
87.	Fred McNeill (G7)	Florida Reliability Coordinating Council										✓
88.	Vicente Ordax (G7)	FRCC										✓
89.	Earl Fair (G7)	Gainesville Regional Utilities	✓									
90.	Angela Battle	Georgia Transmission Corp	✓									
91.	Ken Wofford (G14)	Georgia Transmission Corp.	✓									
92.	David Kiguel (G10)	Hydro One Networks										
93.	Roger Champagne (G10)	HydroQuebec TransEnergie										
94.	Sylvain Clermont (G10)	HydroQuebec TransEnergie										
95.	Roger Champagne	Hydro-Québec TransÉnergie	✓									
96.	Ron Falsetti	IESO		✓								
97.	Kathleen Goodman (G10)	ISO New England										
98.	Brian F. Thumm	ITC Holdings										
99.	Jim Cyrulewski (G8)	JDRJC Associates								✓		
100	Donald Gilbert (G7)	JEA					✓					
101	Ted E. Hobson (G7)	JEA	✓									
102	Gary Baker (G7)	JEA			✓							
103	Don Gilbert	JEA	✓		✓		✓					
104	Harold G. Wyble	Kansas City Power and Light	✓									
105	Tim Wu	LADWP	✓		✓		✓					
106	Scotty Touchette	Lafayette Utilities System	✓		✓		✓					
107	Paul Elwing (G7)	Lakeland Electric					✓					
108	Richard Gilbert (G7)	Lakeland Electric			✓							
109	Larry E. Watt (G7)	Lakeland Electric	✓									
110	Paul Shipps (G7)	Lakeland Electric						✓				
111	Sergio Garza	LCRA TSC	✓									
112	Eric Ruskamp (G9)	LES										
113	Donald Nelson (G10)	MA Dept of Public Utilities										
114	Joseph DePoorter (G8)	Madison Gas & Electric				✓						
115	Ron Mazur	Manitoba Hydro	✓		✓		✓	✓				
116	Jerry Tang (G14)	MEAG	✓									
117	David Weekley (G11)	MEAG Power	✓									

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
118	Robert Coish (G9)	MHEB										
119	David Jacobson (G9)	MHEB										
120	Ron Mazur (G9)	MHEB										
121	Allen McKee (G11)	Midwest ISO (MISO)		✓								
122	Allen McKee (G8)	Midwest ISO, Inc.		✓								
123	Carol Gerou (G9)	Minnesota Power										
124	Terry Bilke (G9)	MISO										
125	Tom Mielnik (G9)	MRO		✓								
126	Michael Brytowski (G9)	MRO										
127	Jerry Tang	Municipal Electric Authority of Georgia	✓									
128	Lewis Ross	Muscatine Power and Water	✓		✓		✓			✓		
129	Carol Sedewitz	National Grid	✓									
130	Denise Roeder (G14)	NC Municipal Power Agency #1			✓							
131	James R. Manning	NCEMC			✓	✓	✓					
132	Robert S. Beadle	NCEMC			✓	✓	✓					
133	Denise Roeder	NCMPA			✓							
134	Bob Cummings	NERC Transmission Issues Subc.										
135	Randy MacDonald (G10)	New Brunswick System Operator										
136	Kathleen Goodman	New England ISO		✓								
137	Walter A. Pfuntner	New York ISO		✓								
138	Greg Campoli (G10)	New York ISO										
139	Ralph Rufrano (G10)	New York Power Authority										
140	Al Adamson (G10)	New York State Reliability Council										
141	Michael Ranalli (G10)	Ngrid US										
142	Reza Rizvi (G10)	Northeast Power Coordinating Council										
143	Rick White	Northeast Utilities	✓									
144	Murale Gopinathan (G10)	Northeast Utilities										
145	John Leland	Northwestern Energy	✓									
146	Guy V. Zito (G10)	NPCC										✓
147	Gregory Sullivan	Nstar Electric and Gas Corp.	✓		✓							
148	John P. Mayhan	OPPD	✓		✓			✓				
149	Keith Mutters (G7)	Orlando Utilities Commission			✓							

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
150	Ganesh Velummylum (G17)	PJM (ISO/RTO)		✓								
151	John Collins	Platte River Power Authority	✓									
152	Mark Byrd	Progress Energy Carolinas	✓		✓		✓	✓				
153	John O'Connor (G12)	Progress Energy Carolinas										
154	Phil Creech (G14)	Progress Energy Carolinas	✓									
155	Lee Schuster (G7)	Progress Energy Florida			✓							
156	Bart White (G7)	Progress Energy Florida			✓							
157	Bart White	Progress Energy Florida, Inc.	✓		✓		✓	✓				
158	Jeffrey Mitchell	ReliabilityFirst Corp.										✓
159	Mark Kuras (G17)	RFC		✓								
160	Mahendra Patel (G17)	RFC		✓								
161	Paul McGlynn (G17)	RFC		✓								
162	Mohamed Osman (G17)	RFC		✓								
163	Chuck Liebold (G17)	RFC		✓								
164	Leanne Harrison (G17)	RFC		✓								
165	Susan McGill (G17)	RFC		✓								
166	Terry Blackwell (G13)	Santee Cooper	✓		✓		✓	✓				
167	James Peterson (G13)	Santee Cooper	✓									
168	Shawn T. Abrams (G13)	Santee Cooper	✓									
169	Vicky Budreau (G13)	Santee Cooper	✓									
170	Art Brown (G13)	Santee Cooper	✓									
171	William Gaither (G13)	Santee Cooper	✓									
172	Glenn Stephens (G13)	Santee Cooper	✓									
173	Rene' Free (G13)	Santee Cooper	✓									
174	Frank Caston (G13)	Santee Cooper	✓									
175	Rick Thornton (G13)	Santee Cooper	✓									
176	James M. Jackson (G13)	Santee Cooper	✓									
177	Wayne Guttormson	SASK Power	✓		✓		✓	✓				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
178	Al McMeekin (G14)	SC Electric & Gas Company	✓									
179	Clay Young (G14)	SC Electric & Gas Company			✓							
180	Phil Kleckley (G11)	SC Electric and Gas			✓							
181	Scott Inglebritson	Seattle City Light	✓		✓	✓	✓					
182	Sharma Kolluri (G12)	SERC EC DRS	✓									
183	Travis Sykes (G11)	SERC EC PSS	✓									
184	Pat Huntley (G11)	SERC Reliability Corp										✓
185	Carter Edge (G14)	SERC Reliability Corporation										✓
186	Maria Haney (G14)	SERC Reliability Corporation										✓
187	Jim Peterson (G14)	SERC RRS OPS	✓									
188	Philip R. Kleckley	South Carolina Electric & Gas	✓		✓		✓					
189	John Ciza (G15)	Southern Company - Generation	✓									
190	Tom Higgins (G15)	Southern Company - Generation					✓					
191	Terry Crawley (G15)	Southern Company - Generation					✓					
192	Roman Carter (G15)	Southern Company - Generation	✓									
193	Marc Butts (G15)	Southern Company - Transmission	✓									
194	J. T. Wood (G15)	Southern Company - Transmission	✓									
195	Jim Viikinsalo (G15)	Southern Company - Transmission	✓									
196	Keith Calhoun (G15)	Southern Company - Transmission	✓									
197	Shih-Min Hsu (G15)	Southern Company - Transmission	✓									
198	Tom Sims (G15)	Southern Company - Transmission	✓									
199	Gary Gorham (G15)	Southern Company - Transmission	✓									
200	Dave Slovensky (G15)	Southern Company - Transmission	✓									
201	Jeremy Bennett (G15)	Southern Company - Transmission	✓									
202	Bob Jones (G15)	Southern Company - Transmission	✓									
203	Bill Botters (G15)	Southern Company - Transmission	✓									
204	Mike Bartlett (G15)	Southern Company - Transmission	✓									
205	Maryanne Mujica (G15)	Southern Company - Transmission	✓									
206	Lee Taylor (G15)	Southern Company -	✓									

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
		Transmission										
207	Perry Stowe (G15)	Southern Company - Transmission	✓									
208	Rod Hardiman (G15)	Southern Company - Transmission	✓									
209	Doug McLaughlin (G15)	Southern Company - Transmission	✓									
210	Randy Castello (G15)	Southern Company - Transmission	✓									
211	Chuck Chakravarthi (G15)	Southern Company - Transmission	✓									
212	Roger Green (G15)	Southern Company - Transmission					✓					
213	Bob Jones (G11)	Southern Company Services	✓									
214	Jim Busbin (G15)	Southern Company Services, Inc.	✓									
215	Bob Jones (G12)	Southern Company Services, Inc. - Trans										
216	Lee Taylor (G12)	Southern Company Services, Inc. - Trans										
217	Rod Hardiman (G14)	Southern Company Services, Inc. - Trans	✓									
218	Doug McLaughlin (G14)	Southern Company Services, Inc. - Trans	✓									
219	Jonathan Sykes	SRP	✓									
220	Ronald L. Donahey	Tampa Electric Company			✓							
221	Thomas J. Szelistowski (G7)	Tampa Electric Company	✓									
222	Scott Helyer	Tenaska, Inc.					✓					
223	Tom Cain (G12)	Tennessee Valley Authority										
224	Ian Grant (G14)	Tennessee Valley Authority	✓									
225	Marjorie Parsons (G14)	Tennessee Valley Authority	✓									
226	Michael Clements (G14)	Tennessee Valley Authority	✓									
227	David Till	Tennessee Valley Authority	✓									
228	Biju Gopi (G10)	The IESO, Ontario										
229	Alex Boutsioulis	The United Illuminating Company	✓									
230	Mark Graham	Tri-State G&T										
231	Gary Trent	Tucson Electric Power Company	✓									
232	Jim Haigh (G9)	WAPA										
233	Steve Rueckert (G16)	WECC Committees and Subgroups										✓
234	Christopher Plante	Wisconsin Public Service Corp			✓	✓	✓					

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
235.	Neal Balu (G9)	WPS			✓		✓	✓				
236.	Pam Oreschnick (G9)	XCEL										

I – Indicates that individual comments were submitted in addition to comments submitted as part of a group
G1 – Dominion Virginia Power
G2 – American Electric Power
G3 – BPA Transmission
G4 – American Public Power Association
G5 – FirstEnergy Corporation
G6 – Florida Power & Light Company
G7 – FRCC
G8 – Midwest ISO, Inc. (MISO)
G9 – Midwest Reliability Organization (MRO)
G10 – NPCC RCG
G11 – SERC EC PSS
G12 – SERC EC DRS
G13 – Santee Cooper
G14 – SERC RRS OPS
G15 – Southern Company Services, Inc.
G16 – WECC Committees and Subgroups
G17 – PJM (ISO/RTO)

Index to Questions, Comments, and Responses

A) New Definitions

Many of the concerns about the existing TPL standards come from the fact that a number of generally understood concepts are embedded in undefined terms, tables, and footnotes. To clarify some of these concerns, the standard drafting team is proposing new definitions. Please indicate whether you agree with the following proposed definitions and provide proposed changes to the definitions if you disagree:

1) **Q1. Base Case: Computer representation of the projected initial or starting Transmission System conditions for a specific point in time. Each base case reflects the forecasted Load at each bus (or node) on the interconnected Transmission System, the transmission facilities which deliver the generation and reactive resources to the connected Load, and the generation dispatch including firm transaction obligations assumed to supply the connected Load. The models also reflect facility ratings in accordance with FAC-008 & FAC-009.**

Summary Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.

Organization	Q1. **Comment**	Agree.	Don't agree.
AECC	Neutral. This is a little wordy but I don't have a better answer.		
ABB	Agree but delete "or node". It is unnecessary.	X	
AEP	Consider replacing"computer" with "model".	X	
ATC	We agree with the definition given in the draft standard date Sep-12, 2007. The last sentence is not consistent with the definition given in the draft standard.		X
CenterPoint CPS Energy	Firm transaction obligations are not used throughout all regions in NERC. Change "including firm transaction obligations" to "including firm transaction obligations where applicable."		X
E ON US	Why define a term that is used only once in the document (R.2.1.2.1) and is, by definition, applicable to a[ny] specific point in time.		X
FPL & FRCC	"Computer" is not appropriate. Replace with "Data model" or "Database model". The last sentence is not clear as to what type of ratings (i.e., normal, short-term emergency, long-term emergency, etc.). Suggest removing sentence completely or rewording as follows: "... in accordance with the documented methodologies required by FAC-008 for each Transmission Owner and Generator Owner."		X
Georgia Transm. Corp	The base case is also a representation of firm transactions through a BES, generation resources, and models reactive components.		X
LADWP	A basecase is a representation of the interconnected power system network at a given instant of time which correctly models an expected network topology in sufficient details (transmission lines, shunt and series compensations, transformers, breakers, phase-shifting transformers, etc.) , the forecasted loads, and a dispatch of connected generations that would achieve load-generation balance to allow a numerical solution without violation of any reliability standards. The resultant flows on the transmission lines are dictated by the Kirchhoff's laws, not laws of commerce, and therefore, cannot		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	be interpreted as either firm or non-firm commercial transactions. A basecase is just a starting point from which transmission planners can make use of to further stress the portion of the systems that are of interests, to properly evaluate the robustness and reliability of the system and to determine line (non-thermal) ratings or network expansions, as needed.		
Northwestern Energy	NWE recommends the words "and may include non-firm transactions" after the words "firm transaction obligations".	X	
NERC TIS	The definition should differentiate between powerflow and dynamics base cases.	X	
LCRA	Should read "Computer model representation of…"	X	
PJM	Also FAC-010.	X	X
Santee Cooper	Delete the phrase "and reactive resources." It is redundant.	X	
SERC RRS OPS	Delete the phrase "and reactive resources."	X	
RFC	To add clarity, the terms "power flow" and "dyanamic" should be included in the definition above. It seems that the defintion may be more detailed than needed without these two terms.		X
Southern Transmission	As stated the definition does not appear to allow for equivalenced system representation since it refers to "each bus on the interconnected Transmission System". The words "as represented in the model" should be added after "interconnected Transmission System" or another sentence should be added stating that equivalenced system representation is acceptable. A definition of a dynamics base case should also be considered.		X
Response: Definition of "base case" has been deleted. Therefore concern is no longer applicable.			
City Water Light and Power	This should not be a defined term in the Glossary, instead there should be a Standard that provides the industry with the requirements for completing a Base Case Study.		X
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies.			
APPA	This should not be a defined term in the Glossary, instead there should be a Standard written that provides the industry with the requirements for completing a Base Case Study. This is the first step in completing the Transmission Studies required in TPL-001. There is no guarantee that the rules used by the transmission planners for the base case studies are done in a reliable manner. The Standard needs to be expanded to insure oversight by the compliance monitors to ensure that the base case is sound from a reliability perspective. Also, both reliability and transparency require that the results of the base case study along with the assumptions used to develop the study must be shared with responsible entities within contiguous areas of the BES, not just with contiguous Planning Coordinators and Transmission Planners. To insure consistent results, the Standard should require that a properly conducted Base Case Study be based on agreed rules for conducting such studies within each		X

Organization	Q1. **Comment**	Agree.	Don't agree.
	interconnection and use of consistent data/assumptions by other entities in the region; otherwise, the results of each PC's and TP's planning horizon studies and the operation planning studies will be brought into question.		
Response: Definition of "base case" has been deleted, as suggested. However, the SDT believes this standard contains requirements for planning reliable transmission systems, including performing appropriate studies. The remainder of APPA's comments is not responsive to Q1 and will be addressed in response to Q43.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	There are a few undefined terms in this definition: "Transmission System" and "interconnected Transmission System". The definition needs to specifically identify what should be modeled and in a manner consistent with other NERC definitions. The definition refers to Facility ratings rather than the general reference to FAC-008 & FAC-009		X
Response: Definition of "base case" has been deleted. However, "Transmission System" is not intended as a new term. "Transmission" and "System" are defined in the NERC Glossary of Terms.			
City Utilities/Springfield	The manner in which the forecasted bus load is determined needs to be defined with clear and consistent assumptions and methodologies such that the results of transmission studies are reasonably valid throughout the entire planning horizon.		X
Response: The SDT believes the additional requirements are too prescriptive for this standard but, if appropriate, may be further detailed in MOD standards, which could be further modified through submittal of a SAR if necessary.			
WECC BPA TSGT TEP	A Base Case can only represent the amount of transactions required to serve connected load modeled in the case (local load?). A Path Rating case (developed to represent maximum transfers on a path) would not be considered a base case under this definition. WECC develops base cases to study high power transfers under stressed conditions. Such high power transfers necessarily include both firm and non-firm transaction obligations. Therefore, a base case that represents firm transactions to support "connected load" only, cannot be used to support studies of maximum possible power transfer and is of limited value in WECC. We agree that the above definition is one definition of a base case, but we feel that it can not be the only definition or the limiting definition. We suggest that wording be included that reflects the concept of modeling forecasted or above forecasted load levels if desired, and both firm and non-firm transactions if necessary to model anticipated maximum transfers and represent stressed system conditions as well. The definition should refer to the base case as a Computer Simulation Model of the power system, not a Computer Representation of the transmission system, since it is used within a computer program and represents load and generation in addition to	X	X

Organization	Q1. **Comment**	Agree.	Don't agree.
	transmission. References to "the generation dispatch and firm transaction obligations to supply the connected load" should be removed. A base case is a starting case for any condition that needs to be studied, not just a firm transactions case. Firm obligations across the transmission system are many times independent of a specific load service obligation.		
Response: Definition of "base case" has been deleted. However, the SDT believes some of these issues, particularly relating to the need to study variations from base case conditions, are addressed by Requirement 2.1.3.			
Ameren	Yes, we agree that the "base case" is a power flow model and is the starting point of the analysis. What we are concerned with are the assumptions that go into the development of the "base case". The season, time of day, load level, generation dispatch assumptions, facilities in service, and interchange assumptions (all based on best available data) are just a small subset of the issues that need to be addressed in the development of the base case. We have concerns that so-called "stressed cases" proposed in the standard for compliance testing may in reality be contingency cases, from which additional compliance performance testing would be required.	X	
Response: Definition of "base case" has been deleted. Furthermore, the term "stressed cases" is no longer used in the revised draft.			
ITC	Firm obligations may possibly include obligations beyond "firm transactions" which most likely means grandfathered transactions and TSRs as you have written it. The planning base cases should have sufficient margins to cover uncertainties as well as "firm transactions". The ATCTDT has "drafts" in place which require that TRM and CBM be included in transmission planning studies for both the near-term and long-term planning horizons. While they are drafts at this stage, consideration should be given to including their requirements in your drafts.	X	
Response: Definition of "base case" has been deleted. The SDT appreciates your comments on TRM and CBM; however, these issues will be covered by a separate drafting team.			
Allegheny Power		X	
New York ISO		X	
NCEMC		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
MRO		X	
Muscatine P&W		X	

Organization	Q1. **Comment**	Agree.	Don't agree.
AECI	No comment.	X	
Brazos Electric	No comment.	X	
Dominion	No comment.	X	
ERCOT ISO	It is a fair description for an initial base case.	X	
IESO	The proposed definition fairly reflects the starting point system model used for planning and operations studies.	X	
Duke Energy		X	
KCPL		X	
LUS		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
Progress–Carolinas		X	
Progress–Florida		X	
SCANA		X	
Tenaska		X	
TVA		X	
BCTC		X	
CAISO	It is a fair description for an initial base case.	X	
WPSC		X	
Response:	Thank you. Please see the Summary Response.		

2) Q2. Consequential Load Loss: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation.

Summary Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. Also the SDT revised this definition as follows to eliminate confusion regarding references to concepts such as fault clearing action, mis-operation, or radial Load:

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Commenter	Q2. **Comment**	Agree.	Don't agree.
ABB	See Q6. Also, from your definition above, a better term would be "directly-connected load loss". This is clear and to the point.		X
Response: The SDT revised this definition to include Load that is no longer connected to a source as a result of the event being studied. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the Load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	My primary concern with TPL-001-1 is that the problems with footnote B of Table 1 in the current TPL standards have merely been given a different dress and makeup and are now being passed off in the definitions of Consequential Load Loss and Non-Consequential Load Loss. I hope this is not the intent and that my concern is a matter of education. None the less, my first impression leads me to the interpretation above. I will attempt to explain. My concern is based in the methodology used to conduct studies and as a result how the consequential and non-consequential definitions will apply. Specifically the use of a breaker to breaker (BtB) contingency methodology verses an element by element (EtE) methodology. By EtE an element is defined as any switchable device either manual or automatic.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	BtB may be useful and may have a place in some system analysis but it only gives a very limited view of the impacts and does not take into account the corresponding operational actions that will take place as a result of a fault event. BtB also does not provide for impacts that might occur during system reconfiguration due to maintenance. EtE provides a much more comprehensive evaluation of the impacts that might be seen on a system and in my opinion is a best practice as opposed to BtB. My concern was raised when during the drafting teams webex on October 11, I heard comments made by the drafting team that "the system should be studied as it is operated". If this comment was intended to mean that events should be studied beyond their initial response then fine otherwise the comment should be clarified. Without clarification, statements like this can be interrupted to mean and only reinforce the mentality that BtB or other inadequate study methods are adequate and can continue to be used. What has all this to do with consequential vs. non-consequesntial load loss? I am getting there. If BtB analysis is permissiable then I disagree with the definitions of consequential and non-consequential load loss. Here is why: It is understandable that a load being normally served (prior to an event) by a radial (meaning one source) will be lost if an event occurs that removes the source. This to me is consequential load. On the other hand, if a load is being served from a transmission line with sources and breakers at both ends (networked) and the line experiences a fault, how is the load on the faulted line classified? Before you jump to an answer, let me explain why I asked. If a fault occurs on a section of the line then obviously both breakers should operate to clear the fault and the load would be removed from the system. This is what is mimicked in breaker to breaker analysis. The problem is that breaker to breaker analysis stops there and some may argue that this is adequate and that the load lost is consequential. I beg to differ. In reality the transmission line will be sectionalized to restore service to the load and isolate the faulted portion of the line. A new steady state condition results one or two radials replacing the faulted transmission line. The impacts of which would be captured if EtE analysis occurs. Because the load is served after the event it should not be classified as consequential. The load being served by resulting radials would not be classified as consequential until the next fault event occurred. Because the system can be sectionalized by switchable devices to establish the new steady state is one reason why switchable devices need to be added to the definition of element.		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	It can be expected from the examples above that the resulting radial(s) serving the load may create greater impacts on the system than the original networked line. The load in this case is not consequential. This is what happens in actual operations, this is what needs to be studied, and the standard needs to ensure that the BES maintains the ability to adequately serve the load following such an event. Having the capability to serve load following the isolation of a faulted section of line is one of the reasons why the networked system was developed in the first place. Another example of radial configuration of networked lines occurs during maintenance. A section of line is taken out of service and ALL load is still served. In this case the load is not consequential because no fault has occurred and again the impacts may be greater than the original networked line. Again these impacts can only be determined by studying the system on an EtE basis. Today's world often forgets that serving load is the reason the BES exist. The BES therefore should be capable of adequately serving the load not only under normal operating conditions and the most common contingency conditions but also under the resulting steady state configuration following a contingency. The BES should be planned in a manner that addresses these contingencies and not in a manner that just seeks to do enough to be able to report compliance. In conclusion, I offer the following recommendations: #1: The definition of Element in the NERC Glossary should be modified to: 1. Include switchable devices either manual or automatic. 2. Clearly define what constitutes an element Suggested modification: Element = Any switchable electrical device (either automatic or manual) with terminals that may be connected to other electrical devices such as a generator, transformer, circuit breaker, bus section, or transmission line. An element may be comprised of one or more elements. The last sentence was struck because you can't define something using the term you are trying to define. #2: The definition of consequential load loss needs further clarification. Consider replacing "due to fault clearing action or misopertion" with "as a result of new steady state conditions following a Planning or Extreme Event."		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	#3: The definition of Planning Events should not be limited to the initial event such as breaker opening for a fault but should include any and all actions taken to sectionalize so that at the end of a Planning Event you have a system that is in steady state and serving as much load as possible. Suggestion: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible. #4: The standard should include the expectation that the BES will be studied at some level (at least n-1) using EtE methodology.		
Response: One of the drivers for developing the definitions for Consequential Load and the use of some entities of BtB methodology referred to in your comments were concerns expressed in interviews by NERC TIS and FERC.. The interviews revealed that some planners were running simulations of single contingency by removing "elements" modeled in the simulation, e.g. impedance data from one bus number to another. This removed "element" did not even necessarily represent a real life switchable system element and this is reflected in requirements R3.2 and R4.2 of the Standard. The concept of Consequential Load was needed to clarify that under certain circumstances the standard allows for load to be dropped following the first contingency. As you indicated the planner must consider how the system can be switched and reconfigured to the point that loadings can be returned to within acceptable limits. The SDT has revised the definition to provide more clarity.			
PJM	Need to tighten definition example- load that trips in sympathy with fault (motor trips as a direct result but not in protection zone)	X	X
Response: The SDT revised the definition to better clarify what constitutes Consequential Load Loss in response to various comments.			
ATC	Voltage sensitive load loss (not due to operator action or UVLS) in response to a disturbance should constitute consequential load loss. Loss (drop) of voltage sensitive load must be included in this definition --- it is not non-consequential loss of load.		X
Response: The SDT revised this definition to include Load that is lost as a result of the Load's response to the transient conditions of the event. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when			

Commenter	Q2. **Comment**	Agree.	Don't agree.
Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
E ON US	I agree with the definiton except for "or mis-operation". The requirements do not, and should not, include mis-operation of protection schemes. We would never finish a study of all potential mis-operations.		X
Response: The SDT revised this definition to exclude any information that could be confusing, including the mention of misoperations. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
BCTC	For the reasons discussed below, we do not agree with the proposed definition. To address our concerns and address the FERC staff concern regarding ambiguity, the proposed definition could be made acceptable to us by modifying it as follows: Load that is no longer served because it either (a) was supplied (wholly or partly) by an element(s) of a radial system or local network that was removed from service due to fault clearing action, was disconnected by controlled interruption to avoid overload of remaining elements of a radial system or local network, or protection or SPS/RAS mis-operation or (b) has dropped out or been tripped during a transient stability period, including an automatic reclosing period, due to a fault on the radial system or local network, including on branches not directly supplying the load. We also offer the following alternative: Resultant loss or controlled interruption of customers supplied by a radial system or local network, due to a fault on or loss of a facility in the radial system or local network. The definition proposed by the SDT removes the second sentence of footnote (b), as directed by FERC, and replaces the first sentence of footnote (b) with a new definition. We agree with the removal of the second sentence of footnote (b). However, we have a concern with this definition replacing the first sentence of footnote (b). We believe that the existing first sentence is a more appropriate definition of consequential load loss and that the proposed definition is more stringent and will have unacceptable impacts on reliability and/or add transmission costs that cannot be justified.		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	The coining of the term "Consequential Load Loss" has been a significant improvement in terminology compared to our reference to footnote (b). However, FERC only used this phase descriptively and did not order NERC to reconsider what would be acceptable consequential load loss (i.e. revise the first sentence of footnote (b)). The definition appears to be based on an interpretation of the new term rather than defining what this term was coined to describe. Order 693 requires that footnote (b) be clarified to not allow loss of firm load or firm transfers - i.e. delete the second sentence. Order 693 then refers to the remaining first sentence as consequential load loss. Order 693 does not address issues regarding whether this should further be restricted to only radial lines, not permitting load loss for outages on local networks. Nothing in the NOPR or the staff paper implies otherwise. The staff paper discusses potential ambiguity regarding which single contingencies load interruption is permitted for. The definition attempts to address this by referring to "directly connected" load. However, this is now ambiguous as "directly connected" might be interpreted to mean only the facility that the load is physically connected to and excluding any upstream facility. BCTC submits that the upstream facilities need to include both radial facilities and local networks. NERC has stated that looped configurations are key for reliable operation. We consider looped configurations and local networks to be the same thing. The proposed definition will make it more difficult to transition from a radial supply to a looped configuration. For radial loads connected by a single radial line, when the load exceeds the line capacity, the transmission owner has alternatives of upgrading the line, adding a second circuit, or converting to a local network by providing a loop from another supply. With the addition of a second circuit or conversion to local network, controlled load interruption may be necessary for loss of one circuit to avoid overload of the second line. Without the option of controlled load interruption, these alternatives will not provide N-1 capability for all loads they supply without addition of a third circuit. This will lead to a economic preference to upgrading of the existing circuit to meet criteria, thereby perpetuating the single radial line configuration. Other alternatives could include splitting the load between the lines or operating with one line out of service so that a single contingency does not overload the facilities remaining in service. However, the addition of a second circuit with controlled load interruption will provide a more reliable load serve than any of these		

Commenter	Q2. **Comment**	Agree.	Don't agree.
	alternatives, because under N-1 more load will remain continuously on line. We expect that the proposed definition will provide greater assurance that existing local networks with N-1 capability will continue to have N-1 capability. However, we have concluded that the definition will introduce an additional unacceptable barrier to transition from N-0 to N-1 supply and that this barrier is not acceptable. We believe that this barrier would be a more significant issue for improving the reliability of supply to all customers than the current situation of permitting some controlled load interruption on local networks. Another issue that arises if local networks are excluded is load response during transient periods. Customers can connect voltage sensitive loads, such as large motors, on long weak systems. During the transient stability period, voltages can dip to below the ride through capability of the load. The fault need not be on the circuit directly supplying the customer, but may be downstream or on another branch facility. Automatic reclosing is often employed to shorten restoration times, but with the consequence of worsening the transient period. Customers have options to install different types of motors, motor controls, local voltage support to mitigate impacts of transient voltage swings, or simply restart motors following the disturbance. If transmission systems are required to ensure no loss of load during transient stability periods for external faults, a first course of action may be to remove automatic reclosing, which will reduce reliability. Alternatively, customer load connections may be denied or additional transmission circuits may be required, which can be costly compared to the customer load options.		
City Water Light and Power	This could be load lost which is on a radial line or load served by facilites which do not have fault-interrupting breakers.	X	
Duke Energy	It is unclear what is meant by "mis-operation". The SDT also needs to address load lost during the transient time frame (e.g. load dropout due to low voltages as a result of a fault) that may not be directly connected to the element removed from service.		X
Entegra	Further examination is needed to determine how to correctly treat loads served downstream from the faulted element, but not directly connected.		X
Georgia Transm. Corp	This definition implies that load that is lost past the directly connected load is allowed. Therefore the definition should be changed to include radially connected load and load that is radialized as a result of a contingency or mis-operation.		X
LADWP	The existing standards do not allow load loss for N-1 contingency unless the load is a radial load of the outage element. This new definition appears an attempt to weaken the requirement by broadening it to anything "directly connected" to an element that is removed from service. While it may be argued that probably only radially connected loads fit this definition, this new definition will lead to more creative		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	interpretation of the word "consequential" and leads all of us down unintended consequence. A radial load is a very specific and clearly defined technical term and should not be changed to a new term that is less precise.		
MRO	The MRO could not agree on the correct definition.		X
Santee Cooper	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "direct load loss".		X
FirstEnergy	We suggest that the team remove "or misoperation" from the definition. This could suggest that an overtrip of protection equipment could result in consequential load loss.		X
NCEMC SERC EC PSS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads.		X
NERC TIS	MISOPERATION has to be qualified as being a misoperaiton on the system element that trips.	X	
RFC	Should the above definition contain a statement that the load is not intentionally lost, since non-consequential load loss is intentional?		X
SERC EC DRS	Add the following to the end of the definition: "or unintentional load lost as a direct result of the event (e.g. load dropout due to low voltages as a result of a fault)."		X
Southern Transmission	This definition only relates to load that is "directly connected" to the specific element being removed. It does not allow for any load that may be or becomes radially connected through another branch that is not part of the facility removed. It does not make sense to not allow the loss of load that is actually electrically radial to the facility being outaged. The definition may work better as "Load that is no longer served because it is directly connected to or radially served through an element(s) that is removed from service due to fault clearing action." The word "mis-operation" is not needed in this definition because none of the contingency events use this term.		X
BPA	Support comments submitted by WECC. The definition needs to consider loads that are tripped sympathetically that may not be directly connected to the element that is removed from service for fault clearing.	X	X
WECC TSGT TEP	Agree with the definition in concept. However, the wording makes the definition seem unrealistic. There are many examples where a certain amount of voltage sensitive load or motor drives sensitive to angle changes are dropped due to normally cleared electrical faults on the transmission system. These loads are not directly connected to the element being removed from service. This type of sympathetic loss of load is	X	X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	unique to the individual customer load. The design of these loads is not under the control of the utilities when it comes to ability to ride through normally cleared faults. We suggest that this definition be modified to include the loss of sensitive load that is not directly connected to the element being removed. We propose the following the definition : Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation, and because of sympathetic tripping associated with normal clearing or mis-operation. Load that is lost because it trips due to low voltages experienced during and immediately following the fault (4-6 cycles?) is also considered consequential load loss. We believe this additional recognition is needed because load lost due to low fault voltages is unavoidable and should not result in a standard violation.		

Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to event being studied.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**

Commenter	Q2. **Comment**	Agree.	Don't agree.
AEP	Consider replacing "Consequential" with better wording (no specific suggestion to offer at this time).	X	
Ameren	A better name for this would be "direct load loss". The definition should include load served by the faulted element but not directly connected to the faulted element.	X	
SERC RRS OPS	The term "mis-operation" introduces ambiguity into the definition, and should be deleted. The definition needs further clarification for consequential and non-consequential loads. For example, loads served downstream from the faulted element but not directly connected should also be considered to be consequential loads. A better name for this would be "Planned Load Loss."		X
Entergy	Delete "mis-operation". For purposes of planning, all consequential load loss should reflect intended fault clearing actions and not unintended fault clearing actions (i.e., mis-operations). Include load loss due to UVLS & SPS in consequential load loss category. Consider using the terms in the existing standard; "Planned Load Loss" and "Unplanned Load Loss" in lieu of Consequential and Non-consequential as they may be		X

Commenter	Q2. **Comment**	Agree.	Don't agree.
	easier to define with each Transmission Owner/Planning Authority responsible for defining the terms considering the impact on the Bulk Electric System. If the terms remain as proposed, the definition needs further clarification for consequential and non-consequential loads. For example, loads entirely dependent on the faulted element but not directly connected should also be defined to be consequential loads.		
HQTE	``directly-connected`` load loss would be more clear	X	X
ITC	Suggest a change in terminology to "direct".	X	
MEAG Power	MEAG believes that deleting the term "mis-operation" as some may have suggested, would significantly narrow the definition of Consequential Load Loss, which in turn would unreasonably increase the amount of load that is Non-Consequential. The Non-consequential load loss, which is not allowed in P1-P5. For example, if mis-operation is deleted from the definition and we consider a relay mis-operation where a breaker fails to clear a fault, then any additional load interrupted by the back-up to the failed breaker/relay is Non-Consequential Load (and the standard appears to be violated since only a single transmission circuit was faulted and Non-Consequential Load was lost).	X	
MISO	Midwest ISO suggests this definition be changed to "Direct Load Loss", as "Consequential Load Loss" may include elements that are not directly connected to the faulted element.		X
SCANA	"Consequential Load Loss" should be termed "Intentional or Planned Load Loss". Not only should direct connected load loss be included, but loads served by or downstream from the faulted element, that is not directly connected to the faulted element, should also be included.		X
Tenaska	Using consequential and non-consequential seem to be misleading. Perhaps using "direct" and "indirect". Also, mis-operation needs some more explanation and to why it should be included here.		X
TVA	We recommend that the terms consequential and non-consequential be changed to direct and indirect. Also, the term should be better defined. We recommend that the definition be "loads that have been de-energized by fault-clearing action or loads that are lost even though the system performance remains within acceptable limits."		X

Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. The SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's

Commenter	Q2. **Comment**	Agree.	Don't agree.
response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
FPL FRCC	Need to clarify what constitues an element (e.g., breaker-to-breaker, line segment to line segment, transformer or capacitor bank)		X
Response: "Element" has been removed.			
SaskPower	What is meant by directly connected? Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability.		X
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied.. Without knowing under what conditions network Load can be shed in Saskatchewan, the SDT does not know whether the proposed standard would cause a change in Saskatchewan's practices or reliability. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements**.**			
Manitoba Hydro	If load losses due to stuck breaker and back-up breaker operations (which would frequently result in the loss of two or more network transmission elements) are not going to be qualified as "Consequential", where should they be placed? MH cannot visualize them as "Non-Consequential", as defined in Q6. Either another "load" category must be developed for these loads, or they should remain as "Consequential". In addition, Consequential Load Loss should include the concept of local area load loss to cover a scenario of islanding with a UFLS in the island, or a small network served at the end of a radial line.Can the SDT comment on why this Local Area defined in the existing TPL stds has been removed?	X	
Response: The SDT reworded the definition to better clarify that Consequential Load Loss is Load loss that occurs when the source to that Load is lost or Load that is lost due to the Load's transient response to the event being studied. However, Load losses associated with a stuck breaker would be considered consequential if they were the result of the initiating event. UFLS activation should not occur on a single Contingency event and would not be considered consequential. A radial Load is directly connected since it has no other source post event and would be consequential. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due~~			

Commenter	Q2. **Comment**	Agree.	Don't agree.
~~to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
APPA	This definition will help define what cascading outage is. There is confusion in the industry and FERC as to "what is a cascading outage." The planning process needs to address this confusion and define exactly what a cascading outage consists. Some want a cascading outage to be when loads beyond the primary or secondary protection equipment are dropped.	X	
Response: The SDT agrees that additional clarification is needed regarding cascading outages. FERC is currently working on modifying this definition. However, the definition of cascading outages is a separate issue from the definition of Consequential Load Loss.			
ERCOT ISO	Agree with the definition.	X	
Northwestern Energy		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Allegheny Power		X	
Exelon		X	
Brazos Electric		X	
LCRA		X	
IESO	This is the same understanding of the IESO.	X	
KCPL		X	
LUS		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
New York ISO		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
Dominion		X	

Commenter	Q2. **Comment**	Agree.	Don't agree.
United Illuminating		X	
WPSC		X	
Response: Thank you. Please see the Summary Response.			

3) Q3. Extreme Events: Events which are more severe than Planning Events and have a low probability of occurrence.

Summary Response: Industry comments were mixed, with some commenters agreeing with the proposed definition and others disagreeing. Among the disagreeing commenters, several noted that a more accurate characterization of Extreme Events would be that Extreme Events have a "lower probability of occurrence than Planning Events" because even Planning Events have a low probability of occurrence. Based on the comments, the SDT revised this definition as follows:

Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.

Commenter	Q3. **Comment**	Agree.	Don't agree.
Ameren	Most planning events have a low probability of occurrence. It appears that the SDT is trying to make a distinction that these Extreme Events would have a lower probability of occurrence than planning events. Consideration should be given to adding the performance requirements with the definition.		X
ITC	R3.4 implies that "Extreme Events" will be studied as per the table. The definition seems functionally correct as applied to the standard but somewhat confusing. The existing wording implies that a mitigation plan should be developed if studies show that "Extreme Events" might cause cascading. If the mitigation plan is a true requirement, saying it is not a planning event can be confusing. "Extreme Events are more severe than Planning Events, have a low probability of occurrence and only require___?????______ in the event of cascade."	X	
WPSC	By definition, Extreme Events are not Planning Events. However, only the definition Planning Events has a requirement to meeting performance requirements. I believe Extreme Events also have performance requirements under R3.4 and its definition should reflect this.		X
Response: The SDT revised this definition in response to various comments. However, the SDT disagrees that performance requirements should be included in the definition as is proposed in the comment. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~.			
ATC Central Maine Power	Suggest "Events which are more severe and have a lower probability of occurrence than the Planning Events"		X
AECC	This is too vague. The old Table 1 did a better job of defining Extreme Events.		X
City Water Light and Power	More needs to be added here, especially to define the phrase "low probability of occurrence". Does this refer to N-1, N-2, N-3 etc.? We have a 300 foot long interconnection line between two substations. In this case even N-1 has a low probability of occurrence. This N-1 event has a much lower probability of occurrence than an N-2 event which involves generator outages. We also have an N-1 SPS event		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
	which hasn't occurred in 25 years.		
E ON US	I disagree with the phrase "and have a low probability of occurance". All the Planning Events, except possibly a generator outage (P1.1), have a low probability of occurance.		X
ERCOT ISO CAISO	Add specificity in this definition. Suggest the following wording: Outage of two or more elements from service with lower probability of occurrence than Planning Events.		X
BCTC	Alternative wording proposed: Events which have a low probability of occurrence and are typically more severe than Planning Events. Explanation: The primary consideration is the probability of occurrence. We do not exclude events simply because they are more severe.		X
Entegra	The statement would be clearer if "low" were changed to "lower".		X
MEAG Power NCEMC Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS TVA	A number of the non-Extreme Events also have a low probability. Recommend change the word to "lower." The definition for "Extreme Events" should reference Table 1.		X
MISO	Extreme Events are clearly described on Table 1. Change definition from "low probability of occurrence to "lower probability of occurrence".		X
MRO	Low probability of occurrence should be in reference to something to be more meaningful. The MRO suggests that the definition be changed to state "lower probability of occurrence than Planning Events."		X
Entergy	Revise to, "Events which are beyond the normal scope of Planning Events and have a lower probability of occurrence."		X
KCPL	Suggest changing "low" to "lower".	X	
LCRA	Define "low probability of occurrence"	X	
National Grid New England ISO Sask Power United Illuminating	Modify to "Events which are more severe,but have a lower probability of occurrence, than Planning Events".		X
FPL FRCC HQTE IESO	Suggest reword as follows: "Events which are more severe and have a lower probability of occurrence than planning events."		X

Commenter	Q3. **Comment**	Agree.	Don't agree.
Manitoba Hydro NYISO NU NPCC RCWS NSTAR			
PJM	Agree with concept but need better definition	X	X
Southern Transmission	Recommend modifying the definition to read: "Events which are more severe than Planning events that are evaluated as required by TPL-001-1 Tables 1 and 2, in part, to identify potential Cascading Outages.		X
Tenaska	I think most people understand, but in this new world we need to put some more specificity around the words "low probability".		X
Response: The SDT revised this definition in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
APPA	The definition is needed; however, this term is dependent on a clear definition of Planning Events, which does not exist.		X
Response: The SDT revised the definition of Planning Events in response to comments received for Q8 with the intent of adding more clarity to this definition. **Planning Events:** Events ~~which~~ that require Transmission system performance requirements to be met.			
Georgia Transm. Corp	All events on the BES have a low probability of occurrence. Extreme Events are those events that have a high consequence to the BES if they were to occur.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. However, the consequence is determined by simulating these lower probability events. Therefore, the SDT believes it would be inappropriate to define the consequence. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
LADWP	Extreme Events for transmission planning should be defined as anything more than N-2. The proposed definition is subjective and not precise. There are examples in this standard as to how this definition can be mis-construed, e.g., cyber attack, wild-fire, hurricanes, etc. These are Extreme Events that belong in emergency planning, not transmission planning.		X
Response: The SDT revised this definition in response to various comments. Specifically, in response to the recommendation of several commenters, the SDT revised the definition of Extreme Events to indicate these events have a lower probability of occurrence than Planning Events. The SDT also modified the standard to clarify Extreme Events.			

Commenter	Q3. **Comment**	Agree.	Don't agree.
Extreme Events: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
NERC TIS	The use of the term Extreme should be limited to those events that are truly extreme. A single line-to-ground fault with delayed clearing (for whatever reason) may require remote clearing of the fault, and trips multiple system elements, without time between elements being outaged. Such events are far too common occurrences to call them extreme.		X
Response: The SDT revised this definition in response to various comments. The SDT also modified the performance tables in response to various comments. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
WECC BPA TSGT TEP	Please add the phrase "two or more elements out of service" to the definition from the previous definition in Table I.	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT believes the suggested phrase would be imprecise for the standard as currently drafted because some Extreme Events do not necessarily involve "two or more elements out of service". For example, one type of "extreme event" is loss of a large Load or major Load center, which might possibly occur without two or more elements out of service. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
Dominion	To make this "crisp", it is suggested that this definition be extended as "Events which …..occurrence. The Transmission system performance requirements do not apply to Extreme Events".	X	
Response: The SDT revised this definition in response to various comments. However, the SDT is concerned that the language proposed in this comment may cause confusion because requirement R3.4 applies to Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability of occurrence~~			
FirstEnergy	The definition is OK, but we question its use in the standard. Many of the items listed as Extreme Events are not considered events. For example, high river temperature is not really an event, it is a condition. The resulting event might be the shut-down of multiple generators.	X	
Response: The SDT revised this definition in response to various comments. The SDT also modified the standard to clarify Extreme Events. **Extreme Events**: Events which are more severe and have a lower probability of occurrence than Planning Events ~~and have a low probability~~			

Commenter	Q3. **Comment**	Agree.	Don't agree.
~~of occurrence~~			
ABB		X	
Allegheny Power		X	
AEP		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Exelon		X	
Duke Energy		X	
LUS		X	
Muscatine P&W		X	
Northwestern Energy		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SCANA		X	
Seattle City Light		X	
AECI	However this could be very subjective.	X	
Response: Thank you. Please see the Summary Response.			

4) Q4. Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond.

Summary Response: Most commenters agreed with the proposed definition, but a few commenters raised issues about the use of the term "beyond". Therefore, the SDT revised the definition as follows to clarify when the horizon may extend beyond ten years:

Long-Term Transmission Planning Horizon: Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.

Commenter	Q4. **Comment**	Agree.	Don't agree.
Central Maine Power NU NSTAR United Illuminating	"A Planning Assessment period that covers years six through ten", is sufficient for the standard." Suggest changing the name to Long-Term Planning Assessment.		X
Response: The SDT believes the term "or beyond" after "years Six through Ten" is necessary for the proposed standard as currently drafted to agree with Requirement R2.2.1, which requires a planning horizon beyond ten years if necessary. Moreover, the use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
FRCC	The definition does not have a reference year when the counting starts. Add the following to the end of the sentence: "... from the current study year."		X
Response: The SDT concurs that a reference year when the counting starts is necessary. The SDT proposed Year One as the reference year when the counting starts.			
AECC	With the time it takes to get transmission planned, approved and built the 10 year time frame is too short. Six to ten year studies are fine but longer term studies need to be performed occasionally. If the requirement remains vague and says 6 to 10 years then what will happen is only 6 year studies. Coupled with the 1 to 5 years in the Near Term Horizon then you potentially set up a situation where you could have a 5 and a 6 year study done. This defeats the purpose of what the intent of the defintion should be. I suggest that 1, 2, 5, 10, 15 year studies be required.		X
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition was revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
LADWP	The objection is not so much about the definition as about what comes after the definition. This standard proposed to include operating and market studies (calling them sensitivities) in the "near-term" planning studies. It appears that the SDT believes this would be easier to justify if the sensitivities is limited to near-term and		X

Commenter	Q4. **Comment**	Agree.	Don't agree.
	not long-term, hence the motivation for breaking the planning horizon. But this is misguided; operating studies belongs in operating standards. They should be addressed appropriately in the TOP for operating scenarios and Market related studies should be addressed in MOD, for example. There are no benefits to include these in transmission planning studies and therefore no need to break up the planning horizon.		
Response: The SDT disagrees and believes sensitivity studies should be performed in the planning horizon. Furthermore, the requirement for sensitivity studies is responsive to FERC Order 693.			
National Grid New England ISO	"Transmission planning period that covers years six through ten", is sufficient for the standard."		X
SRP	Reword to: Transmission planning period that covers years six or beyond.	X	
Response: The SDT believes the definition should clarify the intent that assessments will cover ten years and may extend beyond ten years if necessary (see Requirement R2.2.1). This definition has been revised for additional clarity. **Long-Term Transmission Planning Horizon:** Transmission planning period that covers years six through ten or beyond when required to accommodate any known longer lead time projects that may take longer than ten years to complete.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO		X	
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	

Commenter	Q4. **Comment**	Agree.	Don't agree.
FirstEnergy		X	
FPL		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Consistent with the IESO's understanding.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
Santee Cooper		X	
SaskPower		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SERC RRS OPS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

5) Q5. Near-Term Transmission Planning Horizon: Transmission planning period that covers years one through five.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q5. **Comment**	Agree.	Don't agree.
AECC	I agree with the definition but I don't think studies should necessarily be required for all of the years 1 through 5. Years 1 and 2 probably need to be required because of they are sometimes used as the basis for the development of seasonal models and studies used in the opertional horizon in many Open Access Tariffs.	X	
Response: The minimum requirements for the near term are identified under Requirement R2.1. Past studies can also be included as identified in Requirement R2.6.			
Ameren Santee Cooper SERC RRS OPS	It is suggested that another definition be added for "operations planning horizon".		
Response: The reference to Operations Planning in Q11 was erroneous. The term "operations planning horizon" is not defined because it is not used in the standard.			
LADWP	See my comment above; the only part about the definition that I would retain is to require each of the first five years in a typical ten-year plan be studied instead of just picking one or two years out of the first five years.		X
Response: LADWP's comment does not appear to be directed solely at Q5. In addition, the SDT disagrees with the proposed modification of the requirement.			
Central Maine Power	Suggest changing the name to Near-Term Planning Assessment, and introduce the description the same was as above.	X	
New England ISO NU NSTAR United Illuminating	Suggest changing the name to Near-Term Planning Assessment.	X	
Response: The use of the phrase "planning horizon" in this definition is intended to indicate the period of time applicable to the assessment.			
ABB		X	
ATC		X	
Brazos Electric		X	
City Water Light and Power		X	
Dominion		X	
E ON US		X	
ERCOT ISO	Agree with definition.	X	
Northwestern Energy		X	
AECI		X	
AESO		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Allegheny Power		X	
AEP		X	
APPA	This definition is needed to eliminate the confusion that exists in the industry.	X	
BPA		X	
BCTC		X	
CAISO	Agree with the definition	X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
FirstEnergy		X	
FPL		X	
FRCC		X	
Georgia Transm. Corp		X	
HQTE		X	
IESO	Same as above.	X	
ITC		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
NERC TIS		X	
New York ISO		X	
NCEMC		X	
NPCC RCWS		X	
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	

Commenter	Q5. **Comment**	Agree.	Don't agree.
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

6) **Q6. Non-Consequential Load Loss: Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.**

Summary Response: Based on comments, the SDT revised this definition to specify that this is non-interruptible load as follows to add further clarity:

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

Commenter	Q6. **Comment**	Agree.	Don't agree.
AECC	See my comments on Consequential Load Loss. The definition is too vague to just say "load loss other than Consequential Load Loss". The defintion should be clear and examples should not be used to make the definition. This is a bad habit that NERC has which leads the industry to establish status quo based on the examples and not the definition itself. It sounds like Consequential Load Loss is being tied to short circuit fault events and Non-Consequential Load Loss is being tied to events other than short circuit fault events. Remember that undervoltage, underfrequency and SPS are still triggered by "faults". If that is the intent then say it. Don't put forth a vague definition and then try to justify its meaning by an example.		X
IESO	Suggest to either stop at "automatic operations" or to include other examples since the list is not exhaustive, for example: load that drops out due to unacceptable voltage levels (not tripped intentionally by UVLS.		X
New York ISO	Suggest that examples not be listed or a more exhaustive list be developed.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, the SDT believes that the examples add clarity, even if not exhaustive. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
PJM	Non-Consequential Load Loss should not include load loss due to manual, UVLS and UFLS.	X	X
Response: The SDT believes that Load loss that occurs from manual action, UVLS, or UFLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. The SDT believes that Consequential Load Loss is Load loss that			

Commenter	Q6. **Comment**	Agree.	Don't agree.
occurs when the source to that Load is lost or Load that is lost due to the Load's response to a transient condition of the event being studied. All other Load that is lost is non-consequential.			
ABB	Most people will think of inconsequential, which often means irrelevant, unimportant, or insignificant. But what you are trying to define is the opposite: load loss that is significant, important, and needs to be prevented. Also, whatever you call it, your examples (UVLS, UFLS, SPS) should be expanded to include unintentional and uncontrolled load loss due to low voltage, high current, impedance relays, etc.		X
Ameren Santee Cooper	A better name for this would be "indirect load loss".		
Georgia Transm. Corp HQTE	Suggest a change in title to Indirect Load Loss		X
MISO	Midwest ISO suggests this definition be changed to "Indirect Load Loss", as "Non-Consequential Load Loss" may be confusing regarding the cause-and-effect relationship between a faulted element and subsequent loss of load.		X
SERC RRS OPS	A better name for this would be "Unplanned Load Loss". Load loss that occurs from UFLS, UVLS, load shedding or SPS should be moved to Planned Load Loss. Unplanned load loss would be all other load loss other than planned.		X
TVA	See comment for Q2. We recommend that this term is defined as "load loss other than consequential load loss".		X
ITC	May want to change the terminology as some may interpret this to mean load that is not important and can routinely be shed for any contingency. Suggest 'direct load loss' and 'indirect load loss'. Potential Definition: Load that is not intended to be lost for normal fault clearing or during mis-operation but could be lost either by design, such as under frequency relaying, SPS or backup breaker clearing, or thru manual operator action.	X	
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. Moreover, in response to SERC's comment, the SDT believes that Load loss that occurs from UFLS, UVLS, Load shedding or SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
ATC	Reference to SPS must be excluded from this definition. We recommend that the SDT address what System Elements and/or Load may be tripped by an SPS for each Planning Event in the performance table after N-1-1 scenarios for P3-P5 events.		X

Commenter	Q6. **Comment**	Agree.	Don't agree.
FirstEnergy	We suggest eliminating the reference to Special Protection Systems (SPS). Some SPSs could result in tripping of load in association with a fault. By specifically listing SPSs here, it could imply that if that situation occurs, it would not be considered consequential load drop.		X
Response: The SDT believes that Load loss that occurs from an SPS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss.			
City Water Light and Power APPA	This definition should go beyond just saying "Load loss other than Consequential Load Loss." Recommend adding the following: " . . . including Load Loss that occurs through planned manual (Transmission Operator, Distribution Provider, and so-on) operation or planned automatic operation of load shedding equipment such as under-frequency Load shedding devices or Special Protection Systems."		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
CAISO	Add Remedial Action Schemes (RAS) after "Systems"		X
ERCOT ISO	Add Remedial Action Schemes (RAS) after "Systems" Amend sentence beginning "For example, Load loss that "directly" occurs…		X
Response: The NERC Glossary of Terms clarifies that the terms "Special Protection System" and "Remedial Action Scheme" can be used interchangeably.			
BCTC	See comments on Consequential Load Loss. Propose the following definition to clarify situations for which NCLL is acceptable: Load loss other than Consequential Load Loss to avoid cascading, voltage stability, or blackout of the BES. For example, load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage load shedding, under-frequency load shedding, or SPS/RAS.		X
SCANA	This term is not needed. See comments on "Consequential Load Loss/Intentional Load Loss".		X
Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Among other things, the terms used in the proposed standard are consistent with terms used by FERC. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual~~			

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~(operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Entergy	We recommend to treat load losses due to UVLS & SPS as examples of consequential load loss (refer to question 2).		X
Response: The SDT believes that Load loss that occurs from an SPS or UVLS is not a direct consequence of the event being studied and is in fact the type of distinction the SDT intended to make. FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load Loss			
FPL FRCC	Reword as follows: "Firm load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, excluding curtailments, DSM, and voltage reduction."		X
Response: The SDT revised this definition in response to various comments. However, the SDT ddisagrees with curtailments, DSM, and voltage reduction as these are real-time operating actions that must be taken pre-Contingency and are unrelated to Consequential Load Loss and Non-Consequential Load Loss. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
LADWP	See my comment on the Consequential load loss. Why introduce two new and less precise definitions to replace one existing clearly defined definition? Radial load is precise and clearly defined to transmission planners.		X
Response: See responses to Q2. The SDT revised the definitions of Consequential Load Loss and Non-Consequential Load Loss in response to various comments. However, radial Load is not sufficiently precise and is itself confusing if left as the sole explanation. **Non-Consequential Load Loss:** ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
Tenaska	See Q2 answer.		X
Response: Please refer to the SDT reply to Q2 comments.			
TSGT	same as WECC group comments		X
BPA	Support comments submitted by WECC.		X
WECC	Please add "or Remedial Action schemes" to the end of the definition. FERC Order		X

<table>
<tr><th>Commenter</th><th>Q6. Comment</th><th>Agree.</th><th>Don’t agree.</th></tr>
<tr><td>TEP</td><td>693, paragraph 1773 states (6)“clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.” There needs to be a distinction made between Interruptible Load and Firm Demand.</td><td></td><td></td></tr>
<tr><td colspan="4">Response: The SDT revised this definition in response to various comments. However, the NERC Glossary of Terms clarifies that the terms “Special Protection System” and “Remedial Action Scheme” can be used interchangeably.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.</td></tr>
<tr><td>SaskPower</td><td></td><td></td><td>X</td></tr>
<tr><td colspan="4">Response: The SDT revised this definition in response to various comments.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.</td></tr>
<tr><td>Northwestern Energy</td><td>Include the words "not directly connected" before period of first sentence; and what does "load loss" mean?</td><td>X</td><td>X</td></tr>
<tr><td colspan="4">Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing. Moreover, the SDT believes the term “Load loss” is largely self-explanatory and is further clarified by the examples provided in the definition.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.</td></tr>
<tr><td>AEP</td><td>Consider replacing "Non-Consequential" with better wording (no specific suggestion to offer at this time).</td><td>X</td><td></td></tr>
<tr><td>RFC</td><td>Recommend adding that this load loss is "intentional".</td><td>X</td><td></td></tr>
<tr><td colspan="4">Response: See responses to Q2. The SDT revised this definition in response to various comments. However, the SDT is concerned that the use of alternative terms might be confusing.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection~~</td></tr>
</table>

Commenter	Q6. **Comment**	Agree.	Don't agree.
~~Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.			
AECI		X	
Allegheny Power		X	
Brazos Electric		X	
CenterPoint		X	
Central Maine Power		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Exelon		X	
Dominion		X	
E ON US		X	
KCPL		X	
LUS		X	
LCRA		X	
Manitoba Hydro		X	
MEAG Power		X	
MRO		X	
Muscatine P&W		X	
National Grid		X	
New England ISO		X	
NCEMC		X	
NCMPA		X	
NU		X	
NPCC RCWS		X	
Nstar		X	
Progress–Carolinas		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SERC EC PSS		X	
Southern Transmission	Agree assuming the change in Q2 is made.	X	
United Illuminating		X	
WPSC		X	

Commenter	Q6. **Comment**	Agree.	Don't agree.
Response: Thank you. Please see the Summary Response.			

7) **Q7. Planning Assessment: Documented evaluation of future Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.**

Summary Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~

Commenter	Q7. **Comment**	Agree.	Don't agree.
AECC	Planning assessments shouldn't be limited to the future. Sometimes an assessment needs to be made to benchmark and validate models. Strike: future		X
Response: The SDT revised this definition in response to various comments. However, the purpose of the standard is to assess future transmission needs. Other standards are related to benchmarking and validating models. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
City Water Light and Power	This definition is too vague. A Planning Assessment should cover the Near-Term or Long-Term Planning Horizon and include Base Case and Contingency Analysis according to NERC Standards.		X
Response: Based on the comments, the SDT revised this definition to be more succinct. Other requirements explain the horizon and conditions required to be studied and should not be included in the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
APPA	This is too general. Just about any kind of review will qualify as a Planning Assessment. Suggested definition: "Documented evaluation of future Bulk Electric System needs by the use of performance studies such as NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards."		X
BCTC	Need to insert the word "supported", as below, and further refine, to clarify that the Planning Assessment is not just studies, but includes evaluation of contingencies to be run, sensitivities to consider, etc.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	Documented evaluation of future BES needs, measures to mitigate adverse reliability impacts, and assessments of residual impacts, supported by the use of performance studies ….		
City Utilities/Springfield	Definition should be more clearly defined. Documented evaluation of future Bulk Electric System needs based on the performance requirements as defined for NERC Steady State Transmission Studies or Plant Stability Studies conducted in accordance with the NERC Reliability Standards or more restrictive local area criteria.		
Tenaska	May be best to stop the definition after the word assumptions and cover the details as part of the requirements in the standard itself.		X
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	Eliminate "capital" from the definition. It is not defined or consistently applicable to the standard. Reference to vague "other factors, such as asset conditions and age" should be removed from this standard; there are no consistent definitions or industry standards on which to base this requirement, nor does it appear to be a necessary addition to the standard.		X
Entergy	Remove "and other factors, such as asset conditions and age" from definition. The terms "age" and "condition" are subjective and the age of equipment, if it is well maintained, has little impact on reliability.		X
Exelon	'Other factors' such as condition and age should not be required, but may be utilized if these factors are an integral component of the study.		X
FPL FRCC	Last part of the last sentence should be removed "… and other factors, such as asset conditions and age" does not make sense for planning studies. Equipment condition and age are maintenance issues not transmission planning issues.		X
Georgia Transm. Corp	Asset conditions and age should not be included in the definition. Equipment replacement, in general, is dependent on performance, not age.		X
LADWP	The assessment of asset conditions and age of equipment belongs in maintenance practices, not a transmission planning issue. Similarly, Operating procedures is an operating matter, not planning studies. They have their own standards that could and		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
	should address any issue the SDT may have in mind. Using transmission planning as a catch-all is a wrong headed approach.		
MEAG Power	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. This is a preventive maintenace issue. The age of equipment, if it is well maintained, has little impact on reliability.		X
NCEMC	Generally, we agree but would request NERC to clarify accounting for asset conditions and age within planning assessments. Wouldn't these already be taken into account in the FAC-008 & FAC-009 ratings?	X	
Progress–Carolinas	Planning assessments should not include asset conditions and age.	X	X
Santee Cooper SERC EC PSS SERC RRS OPS	Bulk Electric System deficiencies rather than needs should be evaluated. We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. The term "and other factors" should be better defined or deleted.		X
SaskPower	What is the intent "and other factors, such as asset condition and age"? Seems to broad and outside the scope of NERC. Remove it.		X
SERC EC DRS	Delete the word "needs" and the phrase "such as asset conditions and age." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
Southern Transmission	The term "needs" should be replaced by a term that more aptly describes what is being evaluated. The definition should be ended after the word "assumptions." We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability.		X
TVA	Use of the word "deficiencies" instead of "needs" provides better consistency throughout the standard. We do not agree that the planning assessment should directly include asset conditions and age. Asset condition should be part of the ratings process. The age of equipment, if it is well maintained, has little impact on reliability.		X
Ameren	We do not agree that the planning assessment should include asset conditions and age. The age of equipment, if it is well maintained, has little impact on reliability. If NERC wants a standard to deal with age and maintenance of equipment, then it should develop a separate standard for asset management and not overburden TPL-001-1 with such issues.		X
ATC	We do not agree that "asset conditions and age" belongs in this definition. Furthermore, these factors are not addressed in any requirement.		X
E ON US	I agree that Asset Managers need to consider asset condition and age in their spare equipment and replacement strategies but the impact of these factors is beyond the scope of a deterministic Planning Assessment.		X
Entegra	Should also include validation of reactive power supplies.		X

Commenter	Q7. **Comment**	Agree.	Don't agree.
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
FirstEnergy	We suggest replacing "performance studies" with "past or present studies or information".		X
Response: The requirements define the studies that qualify for use in assessments and are not part of the definition.			
LCRA	"Documented evaluation of future Bulk Electric System performance conducted through performance studies…"		
Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
MRO	This definition is too general. It could be interpreted that the performance studies include resource planning rather than transmission system planning, as well as, asset management. Asset management issues should be beyond the scope of this transmission planning standard. Asset management is an engineering discipline that would require a separate standard or standards and is still a developing activity, for example, there is no industry-wide practice for studying aging issues of transmission equipment while there are industry-wide practices for steady-state, stability, and short circuit modeling and planning of transmission systems. The MRO suggests that the word transmission be added to the definition when referring to needs, performance, and reinforcements and that references to asset management be deleted. Here is a proposed definition "Documented evalution of future Bulk Electric System TRANSMISSION needs by the use of TRANSMISSION SYSTEM performance studies that cover a range of assumptions regarding TRANSMISSION system conditions, time frames, future plans including TRANSMISSION IMPROVEMENTS and operating procedures and other factors." The words in all caps were added or inserted to replace the Drafting Team's original words.		X
Dominion	Suggest to change "…by the use of performance studies that cover……" to "…by the use of past or current performance studies that cover……".	X	X
Northwestern Energy	Insert before performance studies the words "current or past that is known to be	X	X

<table>
<tr><th>Commenter</th><th>Q7. Comment</th><th>Agree.</th><th>Don't agree.</th></tr>
<tr><td></td><td>valid".</td><td></td><td></td></tr>
<tr><td>WECC
BPA
TEP
TSGT</td><td>As identified by the modifications above, we believe the definition should be changed to read, "Documented evaluation of future Bulk Electric System needs by the use of performance studies (steady state and dynamic) that cover a range of reasonable or expected assumptions regarding system conditions, applicable time frames, and future plans; including capital reinforcements and operating procedures, SPS/RAS, and other factors (such as asset conditions and age)."</td><td>X</td><td>X</td></tr>
<tr><td colspan="4">Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in assessments and are not part of the definition.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~</td></tr>
<tr><td>New York ISO</td><td>The word "Documented" is unnecessary. Suggest simplifying the definition to:
Evaluation of future BPS needs to meet forecast demand under the assumed system conditions for the time frame studied.</td><td></td><td>X</td></tr>
<tr><td colspan="4">Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation.</td></tr>
<tr><td>RFC</td><td>Recommend adding power flow and dynamic analyses to this definition. Short circuit analyses should not be included.</td><td></td><td></td></tr>
<tr><td colspan="4">Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. Requirements define the studies that must be performed.

Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~</td></tr>
<tr><td>SCANA</td><td>Bulk Electric System deficiencies rather than needs should be evaluated.</td><td></td><td>X</td></tr>
<tr><td colspan="4">Response: The definition was modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies.</td></tr>
<tr><td>IESO</td><td>The definition covers too much detail on the "how" part, and the "documented" qualifier doesn't seem to be required. Suggest to change it to: Evaluation of future Bulk Electric System needs to meet forecast demand under the assumed system conditions for the time frame studied.</td><td>X</td><td>X</td></tr>
<tr><td colspan="4">Response: Based on the comments, the SDT revised this definition to be more succinct and eliminate the description of the possible range of assumptions. The definition was also modified to clarify that the assessment is an evaluation of Transmission System performance (not needs) and Corrective Action Plans associated with identified deficiencies. The requirements define the studies that qualify for use in</td></tr>
</table>

Commenter	Q7. **Comment**	Agree.	Don't agree.
assessments and are not part of the definition. Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
Brazos Electric	Some discussion of what 'documented' means is needed each time it is mentioned. Is this some form of written report at all times or are 'saved' cases with contingency analysis sufficient at certain times or is it just a means to show that an 'assessment' was performed in some fashion.	X	
Response: Documentation is required as proof that evaluation was performed and guidance is provided as to the content of the documentation. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets.			
Duke Energy	We have a concern with what will be considered acceptable documentation, particularly as it relates to asset conditions and age. Delete the word "needs" and the phrase "such as asset conditions and age". When measures are developed it should be made clear what will constitute an acceptable Planning Assessment.	X	
Response: The SDT revised this definition in response to various comments. Documentation requirements are contained in the standard itself. For example, Requirement R2.7.3 requires documentation of the criteria for determining committed and proposed projects. More clarity may be provided through the subsequent development of compliance measures and auditor worksheets. **Planning Assessment:** Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies. ~~Bulk Electric System needs by the use of performance studies that cover a range of assumptions regarding system conditions, time frames, future plans including capital reinforcements and operating procedures and other factors, such as asset conditions and age.~~			
ABB		X	
AECI		X	
Allegheny Power		X	
AEP		X	
CenterPoint		X	
CPS Energy		X	
ERCOT ISO CAISO	Agree with the definition.	X	
ITC		X	
KCPL		X	
LUS		X	
Manitoba Hydro	A planning assessment should include performance studies.	X	

Commenter	Q7. **Comment**	Agree.	Don't agree.
MISO		X	
Muscatine P&W		X	
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
Response: Thank you. Please see the Summary Response.			

8) Q8. Planning Events: Events which require Transmission system performance requirements to be met.

Summary Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.

Commenter	Q8. **Comment**	Agree.	Don't agree.
AECC	The definition is too vague and does not go far enough to distinguish it from something like and operational event, which only addresses the intial system response and does carry through to the resulting system following the event and subsequent steps that may be taken. Suggest: Planning Events = Events which remove one or more Elements and require Transmission system performance requirements to be met. This definition includes the initial event and any after event actions that result in the system returning to a steady state condition and preventing as serving as much Consequential load as possible.		
Ameren	Consideration should be given to adding the performance requirements in the definition.		X
ATC			X
APPA	What are "performance requirements?" This is too general a statement to be of value for writing specific standards.		X
City Water Light and Power	This statement is too general. Performance Requirements are not defined.		X
City Utilities/Springfield	Minimum performance requirements need to be clearly defined.		X
Georgia Transm. Corp	Performance requirements should be added to the definition.		X
E ON US	Recommend: Events to be simulated is studies (listed in Tables 1 and 2 of TPL-001) which must be documented with Corrective Action Plans when performance requirements of TPL-001 are not met.		X
ERCOT ISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance.		X
CAISO	Needs clarity. Suggest the following wording: Outage of power system elements such as shown in Tables 1 and 2 that need to be considered and simulated to assess Transmission System Performance		X
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Propose, "Events for which Transmission performance requirements must be met".		X

Commenter	Q8. **Comment**	Agree.	Don't agree.
LADWP	The term Event has such a broad connotation that it can be misused by layperson. In fact, it is already misused in this standard as evidenced by including events such as cyber attacks, hurricans, tonados, etc as transmission planning events. These events belongs in "emergency" planning, not transmission planning.		X
Southern Transmission	Change to, "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met as defined in TPL-001-1 Tables 1 and 2."		X
MEAG Power NCEMC Santee Cooper SERC EC PSS SERC RRS OPS	Change to: "Events that are simulated or assessed to test the transmission system to ensure that performance requirements are met."		X
SCANA	Prefer alternate language, "Events for which Transmission system performance requirements must be met."		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition.			
FirstEnergy	We ask that the SDT reword the definition to include reference to the planning events in Table 1 and 2 of this standard. This definition should be specific to this standard and not be included in the NERC glossary.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the SDT believes the definition should be included in the NERC Glossary of Terms to provide common industry terminology.			
IESO NYISO	Linking it to Transmission system performance requirements presents "loop around" argument. Suggest to change it to: Events which need to be considered and simulated in planning assessments to evaluate Transmission system performance.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. Moreover, the proposed revision would not suffice because Extreme Events must also be considered and simulated in planning assessments.			
Manitoba Hydro	The definition of a planned event should relate to the probablity of occurance. Table shows single contingency planned events and multiple contingency planned events. Why has the SDT gone away from the existing categories of events which sorted the events into categories with different levels probability.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. In response to this specific comment, Planning events were considered to have sufficiently high probability of occurrence as to require planned corrective actions - hence the term Planning Event. However, Planning Events have still been sorted into categories with different performance requirements corresponding to different levels of probability and consequence.			
RFC	I don't believe that this is really the definition of "planning events". This defintion should describe generally what the planning events are, not that they must meet performance requirements.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes that a general description of what the planning events are includes the fact that these are the types of events for which performance			

Commenter	Q8. **Comment**	Agree.	Don't agree.
requirements must be met.			
Seattle City Light	List specific types of failures or direct us to a specific table which describes planning events.		X
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. The SDT believes a definition should be established that does not reference a particular part of the standard.			
ABB	Agree but adjust language. You are saying "require requirements to be met". Duh. Even if you took out one of them and said "requirements must be met", this is also redundant. The definition of "requirement" is that it is required. How about "Events for which there are strict transmission performance standards that must be met." This may also be slightly redundant, but not as much as the original.	X	
Response: The majority of the commenters agreed with the proposed definition; therefore, the SDT did not modify the definition. We believe the language, with respect to the use of require and requirements, is correct, and the suggested language does not offer substantive improvement.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Exelon		X	
CPS Energy		X	
FPL		X	
FRCC		X	
Dominion		X	
ITC		X	
KCPL		X	
LCRA		X	
LUS		X	
MISO		X	
MRO		X	
Muscatine P&W		X	

Commenter	Q8. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Carolinas		X	
Progress–Florida		X	
SaskPower		X	
SERC EC DRS		X	
Tenaska		X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you.			

9) **Q9. Plant Stability Study: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**

Summary Response: Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. The SDT revised this definition as follows to further clarify intent:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

Commenter	Q9. **Comment**	Agree.	Don't agree.
ABB	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.		X
Ameren	It seems that the SDT is trying to divide the stability issues between plant (local) and system. As the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. The focus of the studies may be only slightly different, depending on the location, type, and duration of the fault conditions assumed.		X
Central Maine Power NPCC RCWS	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X
FirstEnergy	We believe that this definition is not needed. The Plant Stability Study is similar to the System Stability Study.		X
FPL FRCC	There should be no distinction between Plant Stability and System Stability. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction would be warranted.		X
HQTE National Grid New England ISO NU	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
NSTAR United Illuminating			
BPA	Support comments submitted by WECC. Plant Stability is a subset of System Stability.		X
WECC	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Tenaska	Not convinced that this study needs to be differentiated from a System Stability Study.		X
TEP	Plant Stability seems to be a subset of System Stability. Introducing a new term can cause confusion.		X

Response: The SDT revised this definition in response to various comments. The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~Plant Stability Study~~~~**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.**~~

ATC	Suggest eliminating the sentence after the semi-colon -- the defined term Stability implies what is addressed in the second sentence and is also noted as a performance requirement in footnote 1.a.i to the Stability Performance Table. We also suggest that reference to "in the vicinity" be replaced by "that affect the plant Stability".		X
Santee Cooper SERC RRS OPS	The definition should end at the semi-colon. The remaining part of the definition should be moved to the definition of "System Stability Study."		X

Response: The SDT revised this definition in response to various comments, although much of the sentence after the semi-colon has been retained for clarity regarding generating unit performance. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

Commenter	Q9. **Comment**	Agree.	Don't agree.
~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
City Water Light and Power	Insert "Generating" prior to "Plant" for clarity.		X
APPA	Insert "electric generating" prior to "plant" for clarity. It is unclear as to the intent of this statement. The Standard should require the Transmission Planner to consider contingencies in the vicinity of a particular electric generation plant. However, the ultimate goal of the "Stability Study" is to determine the stability of the BES and not just the "electric generation plant." It is recommended that this be rewritten to make clear the intent of this statement.		X
WPSC	This definition mixes the use of the word "plant" and "generator" which have two different meanings. Suggest re-naming as Generator Stability Study and allow the study of multiple generators at a single site as a plant. The use of "generator" vs. "plant" should also be consistent throughout the standard.		X
Response: The term "plant" has been deleted and the term "generating unit" is being used in the description of the type of study required. The new definition is for a "Generating Unit Stability Study". The SDT made these changes in response to various comments. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
ERCOT ISO CAISO	Definition is not clear. Suggest the following wording: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillations for various contingencies in the vicinity of the plant.		X
IESO	Suggest to replace "Contingencies" with "Planning events", and change the definition as follows: Study of an individual generating plant's capability to remain in synchronism and exhibit damping of the generating units' power oscillation for various Planning events. Note that "in the vicinity of the plant" is removed to not restrict simulations of events only in the vicinity of the plants as experience has shown that an event remote from the plant could also subject the plant to lose synchronism and/or oscillate without		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	acceptable damping.		
New York ISO	"Contingencies" should be replaced with "Planning Events". "in the vicinity of the plant" is too restrictive. Suggest: Study of an individual generating plant's capability to remain in synchronism with damping power oscillation for various Planning Events.		X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Northwestern Energy	System stability studies covers this definition.		X
Response: The SDT believes that it is important to maintain the distinction between Plant and System Stability studies. The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Duke Energy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study.		X
Entergy	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study." Section R4.6 should identify the Generator Owner as the applicable party for doing the Plant Stability Studies.		X
Response: The reference to the "system" has been deleted from the new definition. SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. However, the SDT disagrees			

Commenter	Q9. **Comment**	Agree.	Don't agree.
that the Generator Owner is the applicable party responsible for performing Generating Unit Stability Studies for the purpose of assessing and planning the transmission system, as contemplated by this standard. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
Exelon	Wording should be changed to allow for engineering judgment to determine which contingencies are applied. There may be instances where contingencies outside of the immediate vicinity of the plant may be significant to its stability. Suggest replacing the word 'System' with 'Transmission System'.		X
NERC TIS	Should not be limited to contingencies in the vicinity of the plant. Remove the terms "in the vicinity of the plant." Engineering judgement can then be used without having to define "vicinity." Plant instability can be caused by system events many (sometimes hundreds of) miles away. Plants were shaken off line in British Columbia due to the tripping of units in Arizona in June 2004.		X
Seattle City Light	"…in the vicinity of the plant…" needs to be more specific. How far away must we study?	X	X
Response: The SDT revised this definition in response to various comments. The new definition further clarifies the SDT's intent regarding the "vicinity" that must be considered, although additional buses further away can be studied if desired. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
LADWP	When performing transient stablity studies using either PSSE or PSLF, loss of synchronism and oscillation damping are automatically part of the performance evaluation; it is not a separate study and should not be classifed as a separate study. In the context of transmission planning, unless someone on the SDT use programs		X

Commenter	Q9. **Comment**	Agree.	Don't agree.
	that do not have transient stability package similar to PSSE and PSLF, or has a completely different understanding on the meaning of loss of synchronism and/or damping, there is no need to introduce two new terms to explain a very well understood and established single term known as "transient stability" .		
Response: The SDT believes that it is important to retain the terms to maintain clarity. The SDT revised this definition in response to various comments. However, few if any other commenters expressed concerns about verbiage relating to loss of synchronism and damping of power oscillations. Therefore, this verbiage remained relatively unchanged. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
SERC EC DRS	Delete the term "the effect on the System of." The reference to "System" causes confusion with the term "System Stability Study."		X
Response: The SDT revised the definition in response to various comments to eliminate the reference to the "system". Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
TSGT	Plant stability should be called Station stability. The term "plant" is reserved for aggregates such as total coal plant or total peaking plant, meaning all generating units in that category.		X
Response: The SDT revised the definition to be more general with respect to closely-coupled generating units. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power			

Commenter	Q9. **Comment**	Agree.	Don't agree.
oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before "System".		X
MEAG Power SERC EC PSS	Change " the System" to "local area of the Bulk Electric System." It also need a definition for "plant."	X	
Response: The SDT revised the definition in response to various comments and clarified that the study focuses on an individual generating unit's or electrically closely-coupled generating units' Stability. Please refer to responses to Q32 and the revised definition for additional clarification. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study:** Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~			
AECI		X	
Allegheny Power		X	
AEP		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Entegra		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	
Progress–Florida		X	

Commenter	Q9. **Comment**	Agree.	Don't agree.
SCANA		X	
Southern Transmission	No Additional Comments.	X	
TVA		X	
Response: Thank you. Please see the Summary Response.			

10) Q10. System Stability Study: Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Summary Response: Based on the comments, the SDT revised this definition as follows to add further clarity:

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

Commenter	Q10. **Comment**	Agree.	Don't agree.
Ameren	See comments above in the response to Q9. Specific inclusion of voltage (load) stability seems to be missing from the definition. Also, angular stability is mentioned only as part of the definition for System Stability Study and not Plant Stability Study. It would seem that this item would be part of both types of study.		X
PJM	Does "inter-area oscillations are damped" imply that you also have to do frequency domain analysis? (Because some industry experts would claim that without small signal analysis you cannot ensure that inter-area oscillations are damped.)	X	X
Response: The SDT revised this definition in response to various comments. Based on the responses to Q32 the SDT believes the majority of comments have been addressed. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
ABB	See Q9.		X
Santee Cooper	see Q9 above.		X
SERC RRS OPS	see Q9 above.		X
Response: See response for Q9.			
ATC	Truncate the definition to "……ensure that Stability is maintained." Note that we suggest that "angular" be deleted so that the definition is comprehensive and it includes both voltage and angular stability. Suggest moving the performance attributes in the definition (after the comma) as footnotes to the Stability Performance Table.		X
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
ERCOT ISO	This definition is for a stable system. Study is performed to determine whether system		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
CAISO IESO	is stable or not. Suggest the following wording: Study of the system or portions of the system to assess the system's performance in terms of angular stability, power oscillations and voltage limits during dynamic simulation.		
New York ISO	The study is an assessment. Suggest: Study of the System or portions of the System to assess the System's performance in the domain of angular stability, inter-area oscillations and voltage profile during dynamic simulation.		X
Response: The SDT revised this definition to reflect that the study is for portions of the system. The applicable portions of the System still must be studied and the wording was modified to describe that the study determines whether the System remains stable, not that it ensures stability is maintained. Please refer to responses to Q32 and the revised definition for additional clarification. **System Stability Study:** ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	See comment on Q9; proposed modification, "Study of the System or portions of the System to determine whether plant and system angular Stability is maintained, power oscillations are damped, and voltages during the dynamic simulation stay within acceptable perfomance limits.		X
Progress–Carolinas	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.		X
Response: The SDT believes that it is important to maintain the distinction between Generating Unit (formerly Plant) and System Stability studies. Please refer to responses to Q32 and the revised definition for additional clarification.			
FPL FRCC	Dynamic voltage ratings do not add value and are only an approximation for modeling limitations. The definition should not address performance and should only seek to define the term. Reword as follows: "Study of the System or portions of the System to assess angular Stability and inter-area power oscillations."		X
Response: The SDT believes that it is important to retain the information explaining the purpose of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
LADWP	This comment should be taken together with the comment on Plant stability and I would recommend not to create new terms and go back to use well established engineering terms like Transient Stability Study which covers synchronism, damping,		X

Commenter	Q10. **Comment**	Agree.	Don't agree.
	voltage limits, angular stability, etc. There are many text books that could be used to support this.		
Response: The SDT believes that it is important to retain the terms to maintain clarity. Please refer to responses to Q32 and the revised definition for additional clarification.			
Exelon	Suggest replacing 'System' with 'Transmission System'.	X	
KCPL	Suggest adding "Bulk Electric" before "System".	X	
Manitoba Hydro MISO MRO	The words "Bulk Electric" should be added before both occurances of "System".		X
SERC EC PSS	Change "System" to "Bulk Electric System."	X	
MEAG Power	Change "System or portions of the system" to "Bulk Electric System's components associated with the Transmission Planer."	X	
Response: The SDT believes the reference to the "System" correctly describes the scope of the study. Please refer to responses to Q32 and the revised definition for additional clarification.			
APPA	This is a very clear definition that can be used in Standards. The author did a good job of using defined terms in this definition.		
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
BPA		X	
BCTC		X	
Brazos Electric		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Duke Energy		X	
Entegra		X	
Entergy		X	
Dominion		X	
FirstEnergy		X	
Georgia Transm. Corp		X	
ITC		X	
LCRA		X	
LUS		X	
Muscatine P&W		X	
NCEMC		X	

Commenter	Q10. **Comment**	Agree.	Don't agree.
NERC TIS		X	
Progress–Florida		X	
Seattle City Light		X	
SERC EC DRS		X	
SCANA		X	
Southern Transmission	No Additional Comments.	X	
Tenaska	A generator's loss of synchronism and oscillation issues will be seen in this study.	X	
TVA		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you. Please see the Summary Response.			

11) Q11. Year One: The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner submits their annual studies. Analysis conducted for time horizons within the calendar year from the study publication are assumed to be conducted under the auspices of Operations Planning.

Summary Response: Based on the comments, the SDT modified the definition to clarify that Year One is the first year that requires assessment, not study; and that the planning window begins 12 to 18 months from the completion of the previous assessment. The change reflects the variability in the timing of assessments among different Transmission Planners.

Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.

Commenter	Q11. **Comment**	Agree.	Don't agree.
ABB	Agree but delete "annual". Unnecessarily restrictive. Aren't there non-annual studies for which the definition of "year one" is important?	X	
E ON US	"studies" should be replaced with "Planning Assessment", the Planning Assessment is the documentation (of past and current studies) submitted for review. Note: the definition in Q11 does not match TPL-001.		X
WPSC	Suggest replacing the words "annual studies" with "Planning Assessment".		X
ATC	The definition here is not consistent with what is in the posted standard (the last sentence is extra) -- we agree with the definition in the posted standard.		X
Entergy	The last sentence in the above definition was not included in the definition listed in the draft standard. Consider deleting the last sentence or providing additional examples.		X
FPL	The last sentence of this definition is not included in the Standard. Reword as follows: "The first year that a Transmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner performs their annual studies and submits the results to the RRO."		X
FRCC	The last sentence of this definition is not included in the Standard and should be deleted.		X
MEAG Power Santee Cooper SERC EC PSS SERC RRS OPS Southern Transmission TVA	The last sentence in the above definition was not included in the definition listed in the draft standard, nor should it be.	X	
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Q11 of the comment form. The SDT revised this definition in response to various comments.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
AECC	Year One should be the first year following the current year. The first sentence defines year one just fine. Lose the last two sentences. Completely disagree with the last sentence. Studies are not necessarily conducted on calender year basis and the study publication is irrelevant. This is a planning standard and not an opertions standard. Operational vs planning are driven by the horizon time frame and not a study publication date.		X
ERCOT ISO CAISO	Suggest a shorter definition: Planning window beginning next calendar year.		X
Central Maine Power	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes its annual studies."		X
Duke Energy	Need to provide an example to clarify what this means.		X
FirstEnergy	Although we agree with the concept, the definition is confusing. We suggest simplifying the definition to "The first 12 month period that begins one year and one day from the completion of the study."		X
Georgia Transm. Corp	The first sentence in not necessary. A Planner may use the base case to further assess a problem in the current year. The definition should begin with "The next planning year following current annual studies".		X
HQTE National Grid New England ISO NU NPCC RCWS NSTAR United Illuminating	Modify to, "The first year that a Tranmission Planner is responsible for studying. This is further defined as the planning window that begins the next calendar year from the time the Transmission Planner completes and communicates its annual studies."	X	X
NCEMC	This definition could use further clarification to eliminate inconsistencies in how it may be interpreted. Operations planning horizons may typically be 13 to 18 months from the current date due to the reality that transmission upgrades to address operational performance issues may not be able to be implemented inside this period. Some may assume a 24-36 month operations planning window. Based on this assumption, Year 1 could start anywhere from 13 months from the current date to as much as 37 months from the current date.		X
Brazos Electric	Planners do not 'submit' their studies to ERCOT for evaluation or other. Certain projects are submitted to the group for review and comment but not all studies are	X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
	submitted as normal pratice in all cases. It may be better to use 'create their base cases' or simply 'performs their annual studies' instead of 'submit their annual studies'		
Response: The SDT revised this definition in response to various comments. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
APPA	There is a term in the Glossary that is "Operation Plan;" however, there is not a term defining Operations Planning. It is recommended that the SDT drop the last sentence and define the term Operations Planning for the Glossary. Change "their" to "its."		X
BCTC	One problem with this definition is that it assumes that the Transmission Planner submits annual studies. We need definitions for Operating Horizon and Planning Horizon. Then: Year One: The first year of the Planning Horizon.		X
IESO	Not sure why we need this definition. The standard can simply be worded such that a Transmission Planner is responsible for assessing system needs for time frame beyond the current year. Introducing Operations Planning creates confusion as it is unclear whether this term describes a function or an entity in the context of the proposed definition. Further, the sentence "Analysis conducted for time horizon within the current year from the study publication are assumed to be conducted under the auspices of Operations Planning" is (a) confusing time frame wise, (b) invites debates on the role and responsibility for a term that is not defined in NERC standard or the Functional Model, and (c) is perceived to be prescriptive in organizational setup/responsibility allocation (e.g. why can't a transmission planner conduct operational planning studies?).		X
Response: In the course of reviewing comments, the SDT realized that the definition of Year One in the draft standard varied from the definition of Year One in Question 11 of the comment form. The term "Operations Planning" was used in Q11 but not in the draft standard. Therefore, the SDT revised the definition of Year One in response to various comments but will not introduce a definition for Operations Planning. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
ITC	Adding a statement specifying that this is at least ??? number of months into the future may be prudent.		
Response: The SDT revised this definition in response to various comments. However, in the course of considering this definition and reviewing comments, the SDT believes that the start of Year One will not be a fixed point in time for all Transmission Planners. For example, see NCEMC's comment.			

Commenter	Q11. **Comment**	Agree.	Don't agree.
Year One: The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Seattle City Light	Base cases are developed and studied for seasons, not calendar years. Can the Year One reference be changed to "the year beginning at the next Winter season" instead of the specific "…next calendar year"?	X	X
Response: The SDT revised this definition in response to various comments. However, the SDT has members from a wide variety of NERC regions. In the course of discussing how to define Year One, the team found that practices vary across different regions. For example, many southern regions concentrate on summer peak seasons while others, such as Seattle City Light, may concentrate on winter seasons. The modified definition is intended to accommodate such regional variation. **Year One:** The first year that a Transmission Planner is responsible for ~~studying~~ assessing. This is further defined as the planning window that begins ~~the next calendar year from the time the Transmission Planner submits their annual studies~~ 12-18 months from the completion of the previous annual Planning Assessment.			
Northwestern Energy		X	
AECI		X	
Allegheny Power		X	
AEP		X	
Ameren		X	
BPA		X	
CenterPoint		X	
City Utilities/Springfield		X	
CPS Energy		X	
Dominion		X	
Entegra		X	
Exelon		X	
KCPL		X	
LUS		X	
LADWP	very good clarification!	X	
LCRA		X	
Manitoba Hydro		X	
MISO		X	
MRO		X	
Muscatine P&W		X	
NERC TIS		X	
New York ISO		X	

Commenter	Q11. **Comment**	Agree.	Don't agree.
Progress–Carolinas		X	
Progress–Florida		X	
RFC		X	
SaskPower		X	
SERC EC DRS		X	
SCANA		X	
Tenaska		X	
TSGT		X	
TEP		X	
WECC		X	
Response: Thank you**.** Please see the Summary Response.			

B) Sensitivity Studies

The draft planning standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions" FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed.

In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed system conditions. The standard drafting team has included several parameters that can be varied to create the requisite sensitivity case(s). The draft standards specify that the sensitivities reflect one or more of the following conditions and that documentation be provided explaining the rationale for selecting the sensitivity(ies) employed. The parameters that should be varied include:

- Higher or lower Load forecasts from the Base Case with variability of Load/demand and Load power factors due to season, weather, or time of day.
- Modification of expected transfers.
- Unavailability of long lead time facilities.
- Variability and outages of Reactive Resources.
- Generation additions, retirements, or other dispatch scenarios.
- Decreased effectiveness of controllable Loads and Demand Side Management.
- Modification of planned Transmission outages

To help focus industry discussion, please respond to the questions below:

12) Q12. Should the standard provide more specific direction regarding the number of sensitivity cases that need to be developed?

Summary Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

Question 12			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. However, as long as we're talking about it, NERC should set a standard for the definition of the "peak load" to be planned for. Some utilities use the 50% probability peak load. Some use 90%. A big difference that will result in a big difference in how they are prepared for the peak load days. The sensitivity section is not sufficient to address this. Also, outages of reactive resources should be (and are) in the list of contingencies, not sensitivities.
Response: The standard does not prescribe what percentage of Load needs to be studied. The peak Load to be planned for is defined by the individual entity. The consideration of a higher or lower probability of peak Load is only one of the sensitivity conditions listed in R2.1.3.			

Question 12			
Commenter	Yes	No	Comment
R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:			
Ameren		☑	For the purposes of compliance, we believe that the existing requirement R1 in Standard TPL-001-0 adequately defines the sensitivities that need to be covered in a valid assessment, and no additional clarification is necessary. Deterministic tests of a limited number of system conditions require the application of engineering judgment to evaluate the complex multi-variable problems involved in planning analyses. We all agree that performing contingency analyses on a single snapshot of expected system conditions is not adequate to plan the transmission system, but planning is not a cookbook exercise, and neither is an engineering assessment of planning activities demonstrating required system performance. Further, we believe that a test of incremental transfer capability determined from some of the sensitivity cases needs to be added to the standard and would go a long way to address how much margin exists in the transmission system to handle the unknown or previously undefined variables.
Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. Further the standard is not intended to address how much margin exists in the Transmission System to handle the unknown or previously undefined variables, but to provide base line performance requirements. The entity can provide as much margin as it feels is appropriate. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
AEP	☑		Consider requiring a minimum of two sensitivity cases.
Allegheny Power		☑	Scenario analysis should be based on the unique aspect of the particular Transmission zone. Transmission Planners should work to select the best scenarios related to the specific system and adequately describe the selection process.

Question 12			
Commenter	**Yes**	**No**	**Comment**
APPA		☑	The term Base Case should not be used in this manner. The conditions of the Base Case Study should not be in a Standard to insure that all instability cases are covered.
City Water Light and Power	☑		The term Base Case should not be used in this manner. The conditions of the Base Case Study should be in a Standard to insure that all sensitivity cases are covered.
BCTC	☑	☑	The number of sensitivity cases should be tied to the number of resource plans and range of possible load growth forecast.
Brazos Electric		☑	More descretion should be allowed by the TO or planner in deciding the number of cases.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners. Having too many prescriptive requirements results in concentrating on meeting the requirements rather than on formulating the most effective and efficient improvements.
CPS Energy		☑	The number of sensitivity studies should be at the discretion of Transmission Planners.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
Duke Energy		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated. When Measures are developed, they should provide planners with the flexibility to perform appropriate sensitivity studies.
Entergy		☑	The appropriate studies that should be done by each applicable entity is highly dependent on the transmission system being studied. Being too prescriptive may cause irrelevant studies to be completed while diverting resources and attention from sensitivity studes that the entity most familiar with the transmission system believes could result in more meaningful analysis. The Committee should not lose sight of the importance of good engineering judgment exercised by those most familiar with the characteristics of the particular system. While appropriate sensitivity analyses are beneficial in evaluating system performance, it should be clearly stated that projects and/or mitigation plans are left to the discretion of the Transmission Planners.
ERCOT ISO CAISO		☑	The TP or PA is the best to determine the number and type of sensitivities that are more applicable to their system.
FirstEnergy		☑	We suggest that the SDT reword the standard to allow the Transmission Owner additional latitude as to which stress conditions to study. We suggest modifying R2.4.3 to indicate sensitivities "such as those listed below" be studied. That way the standard would be providing examples but would not dictate specific sensitivity studies that should be performed.
FPL		☑	Not all Regions' sensitivity concerns are the same.
FRCC		☑	Not all Regions' concerns are the same and therefore each Region should determine which sensitivities are appropriate.
Georgia Transm.		☑	Sensitivity analyses should not be prescribed. In one system there may be various sensitivites based on region, generation location, number of long range projects, etc. The Planner should provide a summary of the critical sensitivities and documentation supporting their definitionis.

Question 12			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	We do not support introducing sensitivity testing as requirements in the standard, let alone specifying the number of sensitivity cases that need to be developed. In general, there are two interpretations of sensitivity testing - the type to assist in scoping out planning studies and the type to test the stretched capability of the proposed plans. In the first case, sensitivity testing is conducted to assist in identifying restricting parameters/phenomena, critical faults, and scoping out the conditions that need to be assessed, etc. As such, the scenarios to be included in sensitivity testing vary from one Transmission Planner to another depending on local needs and system characteristics, and even from one study to another for the same area to be assessed. The scope of sensitivity testing is therefore difficult to pin down. In the second case, while variations such as percentage of forecast peak demand can be picked as a common parameter for sensitivity testing, the follow-on actions, or inactions, after obtaining the test results would be at the sole discretion of the Transmission Planner unless they are specifically addressed by reliability standards. Requiring a Transmission Planner to conduct sensitivity testing, and even to require it to study a specific number of cases case may put a Transmission Planner in a quandary. For example, if sensitivity testing for a case with 5% higher than forecast peak load shows that the system needs a new 500 kV line in a certain area, should the Transmission Planner propose the new line? If so, what are the reliability and economic justifications when it is clearly demonstrated that the line is needed only if the load for that studied time frame turns out to be 5% higher than forecast? If the answer is yes (to propose adding the line), then why don't we simply require that all planning studies assume a condition that is more conservative than that forecast, and stipulate these conditions in the standard accordingly? If not, will the Transmission Planner be criticized for not taking proactive action to manage the potential risk? Similarly, a Transmission Planner is faced with a much wider study scope if it is required to study the condition assuming one or more major transmission facility is unavailable due to forced outages. These scenarios are more aptly addressed in operations planning or near operations time frame when transmission facility and other system conditions become more predictable. Studies conducted well in advance of real time already rely on many enabling assumptions. Introducing a requirement for sensitivity testing and with specific number of test cases would render the study task difficult to manage, and may put the Transmission Planner in a quandary dealing with the test results. If the standard should require a Transmission Planner to study up to one transmission facility out of service, then this requirement should be clearly stipulated.
ITC	☑		The standard should provide a minimum number of sensitivity cases that should be developed and should include at least a higher load forecast (90/10 vs. 50/50) and a higher generator unavailiablity (LOLE - 1 in 10).
KCPL		☑	N-1 and N-2 analyses should identify any additional sensitivity cases that need to be studied. This

Question 12			
Commenter	**Yes**	**No**	**Comment**
			standard should not specify the number and type of sensitivities to be studied.
LADWP		☑	the FERC orders are market focused, not reliability focused; to the extent that these orders require sensitivity studies as outlined in this proposed standards, they belongs in operating studies and real time market studies, not transmission planning studies which are to meet reliability based criteria.
Manitoba Hydro		☑	Sensitivity analysis that could be considered will vary from region to region or subregion to subregion.
MEAG Power		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated. Different utilities have different input assumptions, therefore the selection of sensitivities to study are different. For example, some utility needs to study the water availability for its hydro units, while other utility needs to evalauate the sensitivity of gas availability.
MISO		☑	Requirements 2.1.3 and 2.4.3 call for sensitivity cases that stress the system, with documentation as to the rationale for why a particular sensitivity was selected. Midwest ISO believes that the standard must balance clarity and specificity with flexibility and discretion. If the standard is too prescriptive in the system conditions to be evaluated, sensitivity studies that reflect critical system conditions that experience dictates are appropriate for a given system could be construed as being outside of the standards. Such a determination could make the regulatory approvals of facilties needed for reliability purposes difficult or impossible to obtain. Midwest ISO believes hat the language in the existing standard TPL-001-0, R1.3.2, which states that "PA and TP assessments shall cover critical system conditions and study years as deemed appropriate by the responsible entity" provides the proper balance of these issues.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
New York ISO		☑	NYISO does not support the introduction of sensitivity testing in the Planning Standards as a requirement. Sensitivity testing should be dictated by the local needs and system characteristics. The nature of planning studies incorporates assumptions that would make sensitivity analysis difficult to interpret.
NCEMC		☑	There should be a stakeholder process for all entities (all Load-Serving Entities and Transmission Customers) involved or impacted within the defined area to provide input to determine which sensitivity cases are to be performed and the appropriate number of cases that need to be evaluated. Not every sensitivity case should be required for every system.
Northwestern Energy		☑	The current list is too prescriptive as many may not apply to a specific TP, yet they would be required to study it.
Progress–Carolinas		☑	This should be system specific.
ReliabilityFirst	☑		A minimum of at least one or two that contain certain scenarios chosen from the list should be required.

Question 12			
Commenter	**Yes**	**No**	**Comment**
Santee Cooper		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to select the appropriate sensitivities that needs to be evaluated.
SERC EC PSS		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
SERC RRS OPS		☑	These factors vary between areas and regions. In addition the TP should be allowed to assess an alternate sensitivity if they can document that it is more appropriate,
SCE&G		☑	The standard may offer guidance but the entity performing the sensitivity studies should be able to determine the number of cases required.
Southern Transm.		☑	This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.
Tenaska	☑		The question may be misleading as number of sensitivity cases is not the issue. Enough studies should be conducted to appropriately define the boundaries of how the system will perform. The standard identifies various issues that may be used as sensitivity cases, but the list may or may not be all inclusive. The team should ask the industry whether any other sensitivities should be included in the standard.
TVA		☑	The entity performing the studies should be allowed to determine the appropriate number of cases that need to be evaluated.
TEP		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.
WPS			Sensitivity cases do not consider/mention new transmission facilities additions. Although the Transmission Planner should have the ability to determine appropriate sensitivities, system performance based on the delay of new transmission facilities should be considered (may be covered under R2.1.3.3 but could be more explicit).

Response: The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission

Question 12			
Commenter	**Yes**	**No**	**Comment**
Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
E ON US	☑		The proposed requirements P2, P3 and P4 significantly increase system performance. I agree with the requirements but I do not think it is appropropriate to layer extreme load, extreme transfers and other sensitivities on top of these. The analsysis of any Senistivities should be under the umbrella of Extreme Events or limited to meeting the P1 requirements.
HQTE NPCC RCS		☑	The standard is unclear whether or not it mandates the requirement to develop action plans in accordance with consequences of problems highlighted as a result of one of the sensitivity case study. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:"
JEA		☑	Transmission Planners when developing system improvement options should identify their system specific sensitivity cases that best assesses the robustness of the options under consideration. Project evaluation is not addressed in the NERC standards and performing sensitivity assessments that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.
PJM	☑	☑	At the least, it should provide a measure that indicates that you meet the requirement. Need to modify 2.4.3 to specify what if any performance requirement needs to be met.
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating		☑	The standard is unclear whether or not it mandates the requirement to develop action plans for problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System shall be considered, and documentation with the rationale for the sensitivity testing shall be supplied. The sensitivity case(s) may include one or more of the following conditions:" 2.1.3.3 should refer only to planned facilities that may be delayed. 2.1.3.4 - "variability" is too vague for a standard; the standard needs to be more specific as to the intent. 2.1.3.7 should be consistent with 1.4. These comments also apply to 2.4.3.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective			

Question 12			
Commenter	**Yes**	**No**	**Comment**
Actions Plan while leaving it to the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. Requirement R2.7.2 has been modified to make it clear that the entity must explain changes, if any, to the Corrective Action Plans as a result of considering the sensitivity studies. In addition, the SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
MRO		☑	The Drafting Team has provided the appropriate level of detail by indicating that one or more of the following conditions are to be used. However, the MRO notes that R.2.1.3.1 should be changed to match R.2.4.3.1, that is, R.2.1.3. 1 should be changed to state "Variations in Load model assumptions."
Response: The SDT disagrees. The wording in Requirement R.2.4.3.1 is stability related and refers to device characteristics such as motor load as mentioned in Requirement R2.4.1. The wording in Requirement R.2.1.3. 1 refers to "demand" load for steady statae studies.			
Seattle City		☑	Sensitivity studies should be performed at a level higher than LSE or BA. It seems more appropriate for a RC or RRO to determine regional contingencies.
Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC.			
WECC BPA		☑	The TP or PA is the most familiar with the system and so would be the best to determine the sensitivities that are more applicable to their particular system. The Standard should not be overly

Question 12			
Commenter	**Yes**	**No**	**Comment**
TSGT			prescriptive. The Standard can make suggestions or list potential sensitivities but let the TP or PA determine those variables to study and the reasonable range of the sensitivities.

Response: Requirement R2 in the standard states that Planning Assessments, including the sensitivity studies, should be performed by the TP or PC. The SDT believes that there is a need to perform sensitivity studies and to set a minimum level of sensitivities to be considered. To achieve that, the SDT is providing some guidance on what could be included in the sensitivity studies without being too prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

AECC		☑	
AECI		☑	
Exelon		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
SaskPower		☑	
ATC	☑		
City Utilities/Springfield	☑		

Response: Thank you. Please see the Summary Response.

13) Q13. Should the standard specify the required changes, such as changes in expected transfers, load forecasts, generation patterns, etc., from the study case to be considered a "reasonably stressed" case?

Summary Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.

The following requirements were changed due to industry comments:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

Question 13			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	There is no need to build a multitude of sensitivity cases to assess the reliability of the system. The sensitivity issues should be handled on an individual system basis by the local transmission planners as applicable to the study system. Conditions that are considered as "stressed" for one area may require all facilities to be in service in another area. Power flow cases utilizing a number of the

Question 13			
Commenter	**Yes**	**No**	**Comment**
			items listed under R2.1.3 or R2.4.3 could be produced for in-house study work, but such work should not be required as part of standards compliance. The standard should not be dictating what types of sensitivities should be investigated or considered for all parts of the transmission system.
AEP		☑	Consider requiring that the most severe sensitivity cases be included in the studies as determined by the entities conducting the studies.
Brazos Electric		☑	Again, descretion should be allowed by the TO when selecting the criteria.
CenterPoint		☑	See comment to Q12.
Dominion		☑	Transmission Planning engineers have good engineering judgment and need to have some flexibility in selecting the variables that need to be studied.
CPS Energy		☑	The type of sensitivty studies should be at the discretion of Transmission Planners.
Duke Energy		☑	The sensitivities are best selected by those most familiar with the specific system.
Entergy		☑	Should be left to Transmission Planners discretion and good engineering judgement. (see response to Q12)
Exelon		☑	The required changes should not be specified because they may not impact a particular transmission system based upon its geographic location within the interconnection. Required changes should be determined by the entity performing the study.
ERCOT ISO CAISO		☑	Let the TP or PA decide the type of stressing needed for a particular case.
FPL FRCC		☑	The Transmission Planner needs the flexibility to define what are considered "reasonably stressed" cases for their respective systems. This would not a be a proper application of a one size fits all definition.
Georgia Transm.		☑	See comment to Q12.
IESO		☑	See comments above. Also, the term "reasonably stressed" is not measurable.
KCPL		☑	Transmission Planner has best knowledge of conditions that create greatest stress on local transmission system.
LADWP		☑	A "reasnably stressed" case in transmission planning is whether or not the transmission system is stressed. To stress a transmission system, the key parameter to monitor are the line flows. Line flows are dictated by network topology and physics of electricity and very much depends on the objectives of each study, i.e., it is case by case. Standard should focus on what criteria shall be complied, not how to comply. This proposed standard is so prescriptive on how to comply that it reads like a tutorial.
MEAG Power		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case will vary from Transmission Planner to Transmission Planner. Therefore, it should be left to the discretion of the entity performing the study.

Question 13			
Commenter	**Yes**	**No**	**Comment**
MISO		☑	This appears to be a case of expecting that "one size fits all" in requiring that certain scenarios be evaluated. Since the goal here is to improve reliability, it makes more sense to have transmission planners identify appropriate sentivities for area under study. The appropriate sensitivity is likely to vary depending on the portion of system being studied.
Muscatine P&W			Leave it open so it can be driven by local issues including those not in the standards. i.e. Running near term criteria on the long term horizon, additional contingencies beyond currently required, etc. as appropriate for the area.
NCEMC		☑	The standard should offer guidance but what constitutes a "reasonably stressed" case should be left to a stakeholder process as noted in Q12 with some discretion of the entity performing the study.
Northwestern Energy		☑	Each TP's stressed conditions vary, making a list that is applicable to all will not achieve the desired purpose.
Progress–Carolinas		☑	This should be system specific.
Santee Cooper		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SERC EC DRS		☑	The entity performing the studies has the best system specific knowledge to determine what constitutes a reasonable stressed case.
SERC EC PSS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
SERC RRS OPS		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study, since they are the best judge of what stresses the system.
SCE&G		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Southern Transm.		☑	See comment above. [This should not be a "one shoe fits all" exercise. It appears that at least one of these items listed is required even though they may not be the most appropriate ones for all entities. There should be the ability to perform other sensitivity analysis instead of these as long as the "rationale" is provided for the choice. The entity should be allowed to determine the appropriate sensitivity cases.]
TEP		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.
TVA		☑	The standard may offer guidance but what constitutes a "reasonably stressed" case should be left to the discretion of the entity performing the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own			

Question 13			
Commenter	**Yes**	**No**	**Comment**
system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. .			
Allegheny Power		☑	Providing examples would be helpful but specifically stating the required thresholds are transmission system dependent. Providing some methodologies to follow may be prudent such as forecast levels like 90/10; 80/20; or 50/50.
BCTC		☑	Should be tied to the data provided under R1.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~			

<table>
<tr><th colspan="4">Question 13</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
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R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.</td></tr>
<tr><td>Central Maine Power
HQTE
National Grid
New England ISO
NU
NPCC RCS
NSTAR
United Illuminating</td><td></td><td>☑</td><td>The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities.

Reasonably stressed conditions are dependent upon the study area under review and the standard is not likely to be able to be crafted to provide sufficent and consistent direction. However, it might be helpful if the standard clarified whether the base case should include any unplanned generator outages or whether, aside from potential sensitivities, unplanned generator outages are considered only through P1, P3 or P4 Contingencies. If the standard addresses unplanned generator outages only through P1, P3 and P4, then it is recommended that a mandatory sensitivity analysis, with required mitigation, include various potential combinations of a reasonable amount of unplanned outages. The combinations should be based on the part of the system that is under study.</td></tr>
<tr><td colspan="4">**Response:** A new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Requirement R1.4 of the standard requires that long term planned outages are part of the base studies. The performance table provides for specific contingency conditions. The entity may elect to run additional sensitivity studies for even more unplanned outages as stated in Requirement R2.1.4 and document its rationale for doing so.

Note: The words “reasonably stressed” are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.</td></tr>
<tr><td>JEA</td><td></td><td>☑</td><td>Transmission Planners when developing system improvement options should identify their system specific "reasonable stressed" cases including opportunities for additional economic margins that best assesses the economic benefits of the options under consideration. Project evaluation is not addressed in the NERC standards and performing assessments on "reasonable stressed" cases that only lead to operational remedies consistent with the standards, are best performed within the operational horizon where information and assumptions are more certain than within the planning horizon.</td></tr>
</table>

Question 13			
Commenter	**Yes**	**No**	**Comment**
Response: Reliability Standards set the minimum performance requirements and any margins can be set /established and implemented by the entity. The standard covers reliability performance issues and not market or economic performance issues. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
ITC	☑		"Modification of expected transfers" should include unexpected loopflow caused by 3rd parties where applicable. In addition to the obvious impacts on system margins, loopflows have been identified as a major reason that FTR feasibility is hard to predict. Also, see answer to Q12 above. Some level of flexibility for some of the stressed cases should be left to the individual Planning areas as they would know typical load/stresses seen by their systems that should be studied and solutions identified for problems.
MRO		☑	This is unnecessary micro-management of the planning process. The MRO recommends that the Drafting Team proceed with the high-level requirement as provided with the minor changes recommended by the MRO in other parts of this comment form.
ReliabilityFirst		☑	A list of suggestions is sufficient. The flexibility to use different stresses on different systems is

Question 13

Commenter	Yes	No	Comment
			needed.
SaskPower		☑	Unnecessary micro-management of the planning process in the Saskatchewan Regulatory Jurisdiction.
WECC BPA TSGT		☑	No, as in the response for Question #12. The TP is the best to determine the type of stressing needed for a particular case. This is very evident in the type of cases used for studies in the different parts of the NERC regions.

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a corrective action but the entity must explain how the sensitivities affected the Corrective Action Plan.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

Commenter	Yes	No	Comment
New York ISO		☑	See comment to Q12. Additionally, what is the definition of "reasonably stressed"?

Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

Question 13			
Commenter	**Yes**	**No**	**Comment**
Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
WPS		☑	The Transmission Planner should have the ability to determine appropriate sensitivities based on changes to the assumptions within the study. However, those sensitivities should be developed in an open transmission planning process consistent with the transmission planning principles within FERC Order 890.
Response: The SDT agrees. Nothing in the standard precludes an open process. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:			

Question 13			
Commenter	**Yes**	**No**	**Comment**
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. R2.**7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ABB		☑	
AECC		☑	
AECI		☑	
E ON US		☑	
FirstEnergy		☑	
LCRA		☑	
NERC TIS		☑	
Progress–Florida		☑	
Response: Thank you.			
PJM	☑	☑	Again, 'reasonable' is a very subjective term. Refer to comments on question 12
Tenaska	☑		However, what is meant by "reasonably stressed".
Response: Note: The words "reasonably stressed" are only used in the question and do not reference any particular requirement in the standard; therefore, no definition is required.			
APPA	☑		The Standard should indicate a list that says "the list will include but not be limited to:" and then list the minimum necessary to adequately cover the changes in the study.
City Water Power and Light	☑		The Standard should indicate a list which says "the list will include but not be limited to:" then list the minimum changes necessary to adequately cover the changes in the study.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

Question 13			
Commenter	**Yes**	**No**	**Comment**
additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected. **R2.1.3.** For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.1.4.** In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: **R2.4.4.** In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.			
Manitoba Hydro	☑		R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers? Should this encompass simultaneous non-firm transfers? Planning for non-firm falls into an economic study of cost/benefit and not a relibility requirement. R2.1.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.1.3.4: This requirement should be removed and outages of reactive resources should be included in the Table 1 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.1.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s). R.2.1.3.6: This requirement should be removed as this is covered by requirement R2.1.3.1. There is no need to list "decreased effectiveness of controllable loads or DSM" as this is already covered by sensitivity to forecast load and power factor - this will cause confusion. R.2.1.3.7: Modification of planned Transmission outages should be deleted. The need to assess outages in the planning horizon is questionable, so assessing sensitivity to timing of these outages is of very little value. Furthermore, this standard already covers prior outages in its other requirements.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 and Requirement R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 and Requirement R2.4.4 have been added to specifically state that the entity may consider			

Question 13			
Commenter	Yes	No	Comment

additional sensitivities that are appropriate for its own system. In either case the entity must document the technical rationale for why each was selected.

In addition a new requirement, now numbered as Requirement R2.7.2, has been added to clarify that the sensitivity studies do not in themselves establish the need for a Corrective Action but the entity must explain how the sensitivities affected the Corrective Action Plan.

It is the planning entity's decision to establish and document which transfers under Requirement R2.1.3.2 are more significant to study system responses.

The intent of Requirement R2.1.3.3 is for the planning entity to determine the need for alternative plans in the event that previously planned facilities are not installed on time.

Requirement R2.1.3.4 (variability and outages of reactive resources) provides for more unusual or unexpected combination of situations. The contingencies listed in Table 1 usually consider more specific conditions in that the reactive resources are typically connected to circuits or bus sections which are included in Table 1.

Requirement R2.1.3.5 (generation additions, retirements, or other dispatch scenarios) covers future conditions that might exist (such as location, size, numger of facilities) after known connections are made. The FAC standards only consider the initial conditions for known facilities when an entity is requesting connection to the system. Requirement R2.1.3.5 covers the on-going conditions that exist after that connection is made. In addition the requirement covers dispatch scenarios which are not part of the FAC standards.

Requirement R2.1.3.1 is intended to cover all load before any adjustments. This can vary on its own. Requirement R2.1.3.6 covers only a portion of that load and can vary independent of the load forecast. The standard is not just addressing the "net" load but its components.

Requirement R2.1.3.7 parallels Requirement R2.1.3.3 in that "planned" outage durations may vary. It is the entity's responsibility to determene the actions necessaruy to handle extended outages.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:
R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for

Question 13			
Commenter	**Yes**	**No**	**Comment**
why each was selected shall be supplied. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.			
ATC	☑		
City Utilities/Springfield	☑		
Seattle City	☑		
Response: Thank you. Please see the Summary Response.			

14) Q14. The SDT proposes to require the use of sensitivity studies for Near-Term Transmission System Planning Horizon stability analysis. Do you concur with the use of sensitivity analysis in dynamic studies?

Summary Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The commenters generally agree with the concept of considering sensitivities for near-term Stability analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in Load on the entity(ies) System should best be studied. Requirement R2.4.3 has been modified to require documentation of the rationale for why each of the listed sensitivities was or was not selected for running studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are deemed appropriate for its own System and document the rationale for selecting each of them.

R2.1.3.1. Higher or lower Load than forecast~~s~~ed ~~from the Base Case~~ with variability of Load/demand and Load power factors due to season, weather, or time of day.
R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:
R2.4.3.2. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers**.**
R2.4.3.4. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.
R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

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Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The biggest problem with performing stability analysis is getting the stability cases to match up with the power flow cases, and only a limited number of stability cases are developed each year. Further, for those systems that are planned in excess of the NERC Standards regarding stability (3-L-G or 2-L-G vs. 1-L-G as in the Standard), there are no benefits to performing additional sensitivity studies to demonstrate compliance with this standard.
City Water Power and Light		☑	The requirement for sensitivity studies multiplies the study efforts. It will be burdensome especially when interregional studies are performed. It is better to have quality than quantity.
Dominion		☑	Not all the items listed under "B. Sensitivity Studies" may be applicable to stability analysis and also depends on type of stability analysis (Plant/System; angular/voltage). For instance, in some locations stability margins are wide. In such cases, practical experience has shown that such sensitivity analysis is unnecessary. Therefore, this should be applied as applicable, at the engineering judgment of the planning engineers rather than be required by the Standards. In summary, R2.4.3 should be eliminated entirely.
E ON US		☑	Stability studies are a labor intensive task. Off-peak studies (with max plant gen) is severe enough.
SCE&G		☑	Stability studies examine generator and system responses to specific conditions. Because the exact system conditions can not be determined in advance, the sensitivity analysis may not be very

Question 14			
Commenter	**Yes**	**No**	**Comment**
			useful. In addition, stability studies are more time consuming than conventional power flow studies. A preferred approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency.
TSGT		☑	Sensitivity studies are most often used to determine operating relationships of a system - sensitivity to generation patterns is deliverability analysis; sensitivity to load growth is margin analysis. Sensitivity analysis should not be required explicitly. The criteria should be stated in terms of load margins, deliverability, and capability to withstand generator or transaction forced outages. The TP can use sensitivity studies or other reasonable methods to assess reliability
TVA	☑		Consideration should be given to the fact that stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
FirstEnergy	☑		Although we concur with the use of sensitivity analysis in dynamic studies, the standard should not dictate the specific sensitivities studies to be performed.
LADWP	☑		This standard is mixing operational studies with planning studies. The suggested sensitivities in this proposed standards are what operating studies would and should address. It adds no value to the transmission planning by requiring sensitivities in transmission planning just for the sake of it. In addition, performing operating studies more than one year ahead, generally, is quite useless as a general requirement.
Manitoba Hydro	☑		R2.4.3.1: This requirement should include variation in load power factor, as this has a significant impact on transient performance. R2.4.3.3: There is little value in identifying the impact of unavailability of planned facilities. From a reliability perspective, these facilities are required to meet performance requirements. Near term SOLs and IROLs will insure reliability if the facility is late. R.2.4.3.4: This requirement should be removed and dispatch of reactive power devices should be included in the Table 2 contingencies (assuming the intent is to investigate robustness to voltage instability). R.2.4.3.5: This requirement should be removed as this is covered, or should be, by the facility connection standard(s).

Response: The need to conduct sensitivity analysis was a directive in FERC Order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive than steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

Question 14			
Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
AEP			We concur with the use of sensitivity studies, but object to the requirement on what sensitivities to include. The flexibility to determine if sensitivity studies are appropriate, and the flexibility to choose what parameters are appropriate to study for sensitivity should be left open. R2.4.3 as written is restrictive to certain sensitivities and should not be.
CenterPoint		☑	The number and type of sensitivity studies should be left to the judgement of Transmission Planners.
CPS Energy		☑	The number and type of sensitivity studies should be at the discretion of Transmission Planners.
Duke Energy	☑	☑	Sensitivity studies can be useful, but they should only be requried for System Stability Studies. Due to the intensive nature of the studies, the planning engineer should have flexibility to determine appropriate sensitivities to analyze.
ERCOT ISO CAISO		☑	Although we concur with the sensitivity analysis,the TP should determine what sensitivities are more appropriate for their system. Sensitivities should not be scripted in the Standard.
ITC	☑		Both peak and off-peak models have been historically used for stability analysis and should continue to be used. The need for additional sensitivity studies should be left to the discreton of the Transmission Planner.
MEAG Power	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
MISO		☑	Use of sensitivities should not be required for Stability analysis, but the Standard should rather allow sensitivities at the discretion of the planning engineer. Due to the computationally intensive nature of these studies, a study rotation would be appropriate. For example, one year would be peak base case, next year off-peak case, and following year a sensitivity case. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
NCEMC	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated with a stakeholder process for those impacted by these studies as noted above. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.

Question 14			
Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑	☑	The TP should have the ability to determine the sensitivity to use.
Santee Cooper	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
SERC EC PSS SERC RRS OPS	☑		The entity performing the studies should be allowed to determine the appropriate sensitivity studies that need to be evaluated. An alternate approach is to include pre-existing system conditions that additionally stress the system during the contingencies under study so as to verify that stability is preserved under conditions that go beyond those envisioned for the contingency. Stability studies are more time consuming than conventional power flow studies. A single 20 second stability simulation is computationally equivalent to running 80 steady-state powerflow cases and has significantly larger pre-analysis preparation effort.
AECI		☑	We believe that only the worst case would need to be addressed for stability purposes.
WECC BPA TEP	☑	☑	We concur with the use of sensitivities as long as the TPs are allowed to determine the sensitivities that are the more appropriate for their systems and not have the sensitivities scripted in the Standard.
Muscatine P&W	☑		If reasonable and appropriate and allow for local issues including those not in the standards..
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
Entergy		☑	The new requirements for stability studies, including but not limited to the sensitivity studies, will result in a tremendous increase in workload. Because stability studies are so much more time intensive that steady state analysis and because they require personnel with a highly specialized skill set, the number of stability studies required should be increaed only as determined necesssary to evaluate worst-case contingencies. It would seem that the sensitivity analyses as well as many of the multiple contingency analyses could be done for steady state and only worst cases analyzed again by dynamic studies.
FPL FRCC		☑	The standards require near term base case cases to be studied for a broad range of planning and Extreme Events. The sensitivity analysis requirements contained R.2.4.3. will essentially require every dynamic simulation to be run at least twice regardless of whether or not there is any

Question 14			
Commenter	**Yes**	**No**	**Comment**
			engineering insight to be gained. While improved understanding may result from sensitivity analysis of certain key event scenarios, the overall benefits of the sensitivity study requirements contained in section R.2.4.3 do not justify the huge increase in engineering effort to conduct and document these simulations.
Response: The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
KCPL		☑	Dynamic studies should be performed when new generation or transformers are added to the system. Should be performed on a periodic basis, not annually.
Response: The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirement R2.4.3 to stipulate that the entity shall provide the rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard allows that the Planning Assessment can be supported by current or past studies. While an assessment is to be done annually, there is no intent to rerun the same studies "annually" unless the standard specifically requires such. Studies you mentioned can be used to support the assessment and be retained as "past" studies as appropriate. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
MRO		☑	The MRO is okay with requiring the sensitivity studies but is concerned with the R.2.4.3.2 requirement as written in that it unnecessarily requires that the sensitivity studies to "simultaneous transfer" to include "non-firm transfers". The MRO recommends that this be changed to match R.2.1.3.2 "Modification of expected TRANSFERS." The MRO also questions the wording of R.2.4.3.4 which provides a more limiting description of the sensitivity to reactive. The MRO recommends that the wording of this requirement be changed to match R.2.1.3.4, "Variability and outages of reactive resources."
Response: Requirements R2.4.3.2 and R2.4.3.4 have both been revised to match with R2.1.3.2 and R2.1.3.4 respectively. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers. **R2.4.3.4**. ~~Reactive dispatch of generators and other reactive power devices~~ Variability and outages of reactive resources.			
LCRA		☑	

Question 14			
Commenter	**Yes**	**No**	**Comment**
IESO		☑	For similar reasons stated in Q13, above.
New York ISO		☑	See comments to Q12 & Q13.
Response: Thank you.			
PJM	☑	☑	Yes, however, clear direction is needed. Specific wording that defines if you have done enough, and met the compliance requirements.
Response: The need to conduct sensitivity analysis was a directive in FERC order 693 paragraphs 1694,1704, and 1706. The SDT agrees with you that dynamic analysis is generally more labor intensive then steady state analysis. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT have modified Requirement R2.4.3 to stipulate that the entity shall provide rationale for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own System. The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at the entity 's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.4.3.** For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The standard is unclear whether or not it mandates the requirement to mitigate consequences of problems highlighted as a result of one of the sensitivities. Suggest modification to, "…sensitivity testing that stresses the System should be considered. Sensitivity case(s) might include among the following conditions:" 2.4.3 shold mimic 2.1.3 except in regard to load models.
Response: The standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plan while leaving at entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. The SDT has modified wording of Requirement R2.4.3 to be consistent with Requirement R2.1.3 as you suggested. **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied**:**			
SERC EC DRS	☑		Use of sensitivity studies is appropriate only for System Stability Studies.
Response: Thank you.			

Question 14			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		Some sensitivity analysis is reasonable. Other comments: 1. The wording regarding transfer sensitivity for stability analysis should be the same as the wording used in steady state analysis "modification of expected transfers". 2. The list of sensitivities may not be the most appropriate for all entities. There should be the ability to perform other sensitivity analsysis instead of these as long as the "rationale" is provided for the choice.
Response: The SDT has modified the standard so that R2.1.3.2 and R2.4.3.2 are worded consistently. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified requirement R2.4.3 to stipulate that the entity shall provide rational for why sensitivity on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. **R2.4.3.2**. ~~Expected simultaneous transfers including non-firm~~ Modification of expected transfers.			
ABB	☑		Absolutely.
Allegheny Power	☑		
APPA	☑		This is absolutely necessary; it will help with the operational planning that will be needed next. In addition, it will help to determine the amount of study uncertainty that the Transmission Planner believes will be in the plan. This is very important for the Year One.
ATC	☑		
BCTC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
Entegra	☑		Planners should use appropriate sensitivity cases.
Exelon	☑		
Georgia Transm.	☑		
JEA	☑		
NERC TIS	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		

Question 14			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		
Tenaska	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

15) Q15. The draft TPL standard does not require the use of sensitivity studies for the Long-Term Transmission System Planning Horizon (year six and beyond) studies. Do you concur with this approach or should there be some level of sensitivity analysis required for the long-term period?

Summary Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Sensitivities of uncertain models could result in even more uncertain and probably unrealistic conditions, the use of which may cloud the actual trends. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	In the long range the confidence in some variables such as load growth may become fuzzy. Sensitivity analysis let you gauge the impacts that variences in a particular variable may have. I don't think it should be performed for every study but occasional study to maintain sanity is appropiate.
Response: Because the assumptions for the longer term are fuzzy, the SDT did not feel that it was appropriate to require prescriptive sensitivities since such studies could result in an even more distorted model. The SDT felt that the entity should determine if such sensitivities are appropriate knowing their own unique circumstances			
Northwestern Energy		☑	However, the TP should have the ability to determine the sensitivity to use.
Response: The TP can always perform and use sensitivities in addition to those required in the standard.			
AEP		☑	Consider requiring the same sensitivity analysis that is conducted under the near-term studies.
NERC TIS		☑	Since the long-term planning is completely couched in uncertainty, at least some generalized sensitivities should be required.
NCEMC		☑	Some sensitivity analysis in the long term years should be done (90/10 load with higher than expected transfers and/or delayed baseload generation) so that higher voltage issues are adequately tested to identify long lead time upgrades, in a similar manner as was done to justify the backbone projects that have been identified in the PJM Interconnection. A stakeholder process should be used by the entity performing the study to compile input on impacted LSEs and other Transmission Customers.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
BCTC	☑	☑	Long term needs to address sensitivities since it usually takes more than five years to contruct new transmission lines.
ITC	☑		We believe that both near-term and long-term studies should include sensitivity studies. Near-term studies may produce either operating solutions and more limited transmission solutions. It is just as or more important in a standard like this one to also do sensitivity analysis for the 6-10 year and

Question 15			
Commenter	**Yes**	**No**	**Comment**
			beyond period. This is necessary to provide the needed advance notice for long-lead time alternatives to problems which are uncovered. Focusing on the next 5 years limits alternatives that can be implemented. In fact, it makes sense to perform more sensitivity analysis on the longer term as assumptions become less probable the further out into the future you get. If a problem is identified in one snapshot 10 years out it may be less relevant than if it shows up in several varying snapshots 10 years out into the future. The use of sensitivity studies for the 6-10+ year horizon will hopefully have the effect of minimizing the use of band-aid type approaches to identified problems.
Tenaska		☑	Any analysis that is performed needs to include some sort of sensitivity analysis. In fact, the sensitivity analysis may yield more information that is helpful in making decisions today than sensitivities performed on a near term study. A way of conducting a sensitivity analysis for long term studies may be to require long term studies to be performed for several years instead of only the one year that is required in the 6-10 year horizon.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
TSGT		☑	It is just as important for long range plans of service to provide acceptable operation as it is for near-term facility plans. To specify different criteria for different time periods seems unreasonable.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. This is not the same for the near-term. The SDT feels that the level of uncertainty for the two time period justifies a different approach. In any case, the standard does not preclude entities from performing long term sensitivity studies.			
ERCOT ISO CAISO WECC	☑		Agree. The Standard should state that sensitivity studies are not required but the TP or PA could use sensitivities if desired.
TEP	☑		We agree with this conclusion. The Standard language should state that sensitivities are not required in Long-Term Transmission System Planning Horizon but the TP could use sensitivities if desired.
Response: The SDT feels the standard reflects your comment. The standard does not preclude the entity from using sesitivities if more critical trends are detected.			
Georgia Transm.	☑		The sensitivities should be determined by the Planner. As part of the development of long range projects, sensitivity analyses should be performed.
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired. Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties.			
Ameren	☑		There are more unknowns in the longer-term studies than in the near-term studies, which would

Question 15			
Commenter	**Yes**	**No**	**Comment**
			indicate that more sensitivity studies would need to be performed and not less. However, it is more reasonable to suggest that if near-term sensitivity studies show a problem in a particular part of the system, then similar sensitivity studies need to be performed in the longer-term analyses.
IESO	☑		We agree, but this raised a question on why did the SDT introduce a requirement for sensitivity testing for year one to year 5 studies but not the year 6 and beyond studies. Wouldn't the degree of uncertainty be higher in the longer time frame?
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability. The standard does not preclude entities from performing long term sensitivity studies which may even provide some basis for the base models used for analysis.			
LADWP	☑		This applies to both long- and near- term, the type of sensitivities proposed here do not belong in transmission planning studies.
Response: The SDT felt that it is necessary for planners to consider certain factors that clearly could impact system responses to contingencies. The standard, sub requirements for R2.1 and R2.4, has been modified to require that the planner document why or why not the listed factors were used in the assessment. In addition the standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Muscatine P&W	☑		Local issues may drive a different approach
Response: The SDT feels the standard reflects your comment in that even though the standard does not require sensitivities, it does not preclude the entity from using sesitivities if desired, such as local issues as you suggest.			
New York ISO	☑		NYISO does not agree with the requirement of sensitivity studies in the near-term or long-term.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. Closer in years tend to be more certain and applying sensitivities is necessary to ensure that unexpected conditions would not significantly affect reliability.			
WPS	☑		The standard should require long-term sensitivity studies to the extent that the open transmission planning process within FERC Order 890 identifies the need for the sensitivities.
Response: Commenters generally agreed that sensitivities are not needed in long-term planning horizon studies since the studies are typically based on a number of assumptions regarding future conditions and uncertainties. In addition the SDT feels that such sensitivities were not required by the Order. The standard does not preclude entities from performing long term sensitivity studies which may provide some basis for the base models used for analysis nor does it preclude studying multiple years if more critical trends are detected.			
Brazos Electric	☑		Longer term studies should be performed in the broadest sense, the cases are difficult to create accurately and a greater range of sensitivities do not improve the results.
City Water Power and Light	☑		
Dominion	☑		We concur that no sensitivity studies should be required for the LT planning horizon.
E ON US			I agree with the approach.

Question 15			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		
Allegheny Power	☑		No sensistivity needed for long term assessment.
APPA	☑		The sensitivity study of year 6 and beyond is of little value. The uncertainty (standard deviations) in the input assumptions used to complete the studies for 6 years and longer are so large it would not provide useful answers to make sound decisions regarding the need to build, remove, or improve BES facilities.
ATC	☑		
BPA	☑		
CenterPoint	☑		
Central Maine Power	☑		There is no need for sensitivity analysis.
City Utilities/Springfield	☑		
CPS Energy	☑	☑	We concur with not requiring sensitivity studies for the Long Term Assessment.
Duke Energy	☑		Agreed, sensitivity studies should not be required for the Long-Term.
Entergy	☑		
Exelon	☑		
FirstEnergy	☑		Yes, we concur with this approach and sensitivity analysis should not be required.
FPL	☑		There should be no sensitivity studies/analyses for the Long-Term Transmission System Planning Horizon.
FRCC	☑		
HQTE	☑		There is no need for sensitivity analysis.
JEA	☑		
KCPL	☑		Long term planning horizon has significantly greater uncertainty in future conditions and sensitivity studies are unlikely to contribute to reliability because of this.
LCRA	☑		There are two questions asked and the response is yes to both. In the ERCOT region, load flow cases are not currently availbale for years 6-10 and this limits the long-term study activity that Transmsion Owners and Transmission Planners can acarry out. As currently proposed (R2.2) is appropriate.
Manitoba Hydro	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainty that the base planning is a sensitivity study itself. Sensitivity studies in these years would be a waste of time. The long term analysis should be used to indicate trends such as a reduction in transfer capability, reduction in damping, etc, but not necessarily seek mitigation of such trends.

Question 15			
Commenter	**Yes**	**No**	**Comment**
MEAG Power	☑		We concur with the current approach.
MISO	☑		Long-term planning horizon studies are typically based on a number of assumptions regarding future conditions and uncertainties. While testing various load conditions, generator operation assumptions, and power interchange variables may be useful for modeling expected economic value, such analysis does not contribute to reliability.
MRO	☑		The models for Long-Term Transmission System Planning Horizon typically contain such uncertainy that the base planning is a sensitivity study iteself. The MRO believes that sensitivity studies in these years would be a waste of time.
National Grid	☑		There is no need for sensitivity analysis.
New England ISO	☑		There is no need for sensitivity analysis.
NCMPA			
NU	☑		There is no need for sensitivity analysis.
NPCC RCS	☑		There is no need for sensitivity analysis.
Nstar	☑		There is no need for sensitivity analysis.
PJM	☑	☑	PJM agrees that no sensitivity analysis is required for long term period
Progress–Carolinas	☑		Sensitivities should not be required for Long-Term
Progress–Florida	☑		PEF concurs with the draft standard's approach with regard to Q15 that sensitivities should not be required for years six through ten.
ReliabilityFirst	☑		
Santee Cooper	☑		We concur with the current approach.
SaskPower	☑		
Seattle City	☑		Conditions six years or more in the future are unpredictable and sensitivity studies would provide results of limited usefulness.
SERC EC DRS	☑		We agree that sensitivity studies should not be required for the Long-Term..
SERC EC PSS	☑		We concur with the current approach.
SERC RRS OPS	☑		We concur with the current approach.
SCE&G	☑		
Southern Transm.	☑		Yes, we concur with this approach.
TVA	☑		

Question 15			
Commenter	**Yes**	**No**	**Comment**
United Illuminating	☑		There is no need for sensitivity analysis.
Response: Thank you.			

C) Corrective Action Plans

Requirement R2.7 of the standard states that when analysis shows that the performance requirements in Table 1 and Table 2 are not fully met, a Corrective Action Plan that utilizes all or some of the Transmission System enhancements, generation additions, DSM, new technologies and Operating Procedures shall be included in the Planning Assessment. This Corrective Action Plan should ensure that upon its implementation the identified system deficiencies will be corrected so that the performance requirements in Table 1 and Table 2 will be met. Furthermore, studies included in the Planning Assessment should demonstrate that this is indeed the case.

16) Q16. Requirement R2.7.1: Such Corrective Action Plans shall "Identify System deficiencies and the associated actions needed to achieve required System performance including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of Interim Operating Procedures". System deficiencies may be corrected using an integrated plan, i.e., an optimal mix of Transmission, generation, DSM and Operating Procedures. Should DSM be considered in conjunction with other measures in developing Corrective Action Plans? If yes, please comment on how the impact of DSM should be included.

Summary Response: DSM refers to reduction in the net Load that could be used to mitigate generation deficiency or Transmission overload. DSM could be invoked pre-Contingency or as a part of automatic or manual System adjustment post-Contingency. The use of DSM is optional and entities do not have to include DSM in the Corrective Action Plan. However, if DSM is included in the Corrective Action Plan, the entity that included it must justify the DSM amount and associated uncertainties. If an entity can show that DSM is effective, the standard does not bar them from using it.

The following requirement was changed due to industry comments:

R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

Q16			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	Yes - DSM impact should be included if it is known and can be treated the same a generation as far a dependibility, capability, and its known impacts. No - most DSM on our system is already figured into the load.
Response: The SDT provided DSM as a possible action. The entity may choose to use this option or provide additional actions to improve System response.			
Ameren	☑	☑	If DSM can be implemented in the required operating time, we have no objections to using DSM as the planned mitigation to relieve overloads or low system voltages for multiple contingency conditions, but not as a long-term solution for single contingency conditions. However, from our experience, we believe that developing enough DSM in the required time at specific locations in the

Q16			
Commenter	**Yes**	**No**	**Comment**
			system will be difficult, and that plain load-shedding would be required to supplement the DSM to achieve the desired performance.
BPA	☑	☑	Support comments submitted by WECC. There is a concern with using DSM as a corrective action if it is not directly controlled by the utility and the benefits do not materialize as planned.
Brazos Electric		☑	If DSM is not viable due to market failings, then its inclusion in any CAPs provides an inaccurate soltion to achieve the required system performance.
City Water Power and Light		☑	DSM is not always available and is usually not available without operator action. Therefore, asuming it is alwasys available could give a false sense of security. The system could collapse before DSM is able to be implemented.
Georgia Transm.		☑	DSM should not be a requirement in considering Corrective Action Plans. Because DSM cannot be counted on or controlled, its use as a Corrective Action Plan should not be assumed.
MISO	☑	☑	Yes, DSM should be considered in transmission studies, but should be limited to firmly contracted DSM resources that are demonstrably applicable for transmission capacity mitigation. DSM is better compared to supply-side resources as they are evaluated for reserve margin contribution. No, the challenge in considering DSM, is that Transmission Planners are not aware of DSM potential on the system and it must be communicated to them for consideration.
WECC TEP		☑	It is unclear whether "DSM" in this question refers to reduction in load or increases in distributed resources, or if the resources are directly controllable by the transmission operator. DSM could be used in the mix of solutions that are used to determine the optimal solution for a transmission issue. However, we have concerns about the use of DSM, that is not under the direct control of the Transmission Operator as a stand alone transmission system solution. Please remember the overstated returns from DSM in the last decade that did not materialize. If these overstated values had been used as a transmission system enhancement, then the system would have been compromised with emergency operating solution until the effective transmission enhancements could be realized.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
E ON US		☑	DSM and generation improvements should be excluded. What is a "generation improvement"? New technologies could apply to anything, does the SDT mean "new Transmission technologies"?
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it. The term "generation improvements" means any change or modification to a generator which results in an increase in generation output and/or reactive support. New technologies include any technology that is not currently in use on the electric power System that helps improve efficiency (i.e., energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Northwestern Energy		☑	The word "including" should be "may include", mandating what should be studied is not appropriate.

Q16			
Commenter	**Yes**	**No**	**Comment**
			Also, including DSM in the list presumes the balancing area is deficient in generation, which may not always be the case.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use “may include” instead of “including”. DSM typically has been used to compensate for generation deficiency but it can also be used to reduce transmission loading for special conditions and may provide a justifiable corrective action. The standard does allow for the use of DSM but other factors may disallow the use of DSM as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
CenterPoint		☑	CenterPoint Energy is not aware of DSM ever being identified as an effective option to correct a transmission system deficiency. If such an application of DSM was identified and implemented, load growth would quickly negate the DSM impact, and other measures would have to be taken.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		DSM should be included to the extent that its performance is sufficiently and consistently understood. The standard does not use the term "optimal" Therefore, the Drafting Team appears to be interpreting the Standard to require a vertically-integrated Planner to produce a so-called optimal-mix of resources plan. This would be an incorrect assumption and is not required. In areas with independent planners and competitive wholesale markets, it is sufficent to identify system needs and produce a plan that identifies regulated transmission solutions in the event that market-based resources (such as DSM) do not address those identified needs. Therefore, while DSM can be as effective a resource as generation, per Commission Orders, in areas with ISOs/RTOs and a competitive wholesale market, the NERC Standard cannot prescribe the development so-called optimized (as is suggesgted by the Drafting Team) resource-mix plans, as identified by a central planner.
NERC TIS	☑	☑	Yes, if it can be counted on for relieving transmission constraints. Some DSM contracts do not allow for interruption for anything other than resource adequacy events, or have time-based or economics-based implementation limitations.
New York ISO	☑		NYISO suggests that the impact included in studies should consider past performance of DSM participants.
Response: The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
CPS Energy		☑	Performance of the DSM is not necessarily controlled by the Transmission Owner and cannot be considered "firm". Therefore, use of DSM should be optional, but not mandated.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use “may include” instead of “including”. If an entity can show that DSM is effective, the standard should not bar them from using it.			

Q16			
Commenter	**Yes**	**No**	**Comment**
R2.7.1 - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
FirstEnergy		☑	We do not feel that the standard should specify, limit, or suggest methods for mitigating system performance deficiencies. We suggest rewording R2.7.1 by ending the first sentence after the words "System performance". The items currently described could be moved to a reference document which could include DSM and other mitigation methods.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use “may include” instead of “including”. The SDT feels it is more useful to include examples of what the Corrective Action Plan may include. The list of examples should help minimize questions regarding what is valid as a corrective action. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
IESO		☑	No, the amount DSM is, in some established markets, a market-arranged quantity that depends on both the offered price and the discretion of the LSE or load customer at the time such a price signal presents itself. The resultant amount of DSM that can actually be realized when needed is unpredictable. This requirement also brings up a broader issue. Requirement 2 generally applies to Planning Coordinator and Transmission Planner, there is no distinction made as to which sub-requirements apply to which entity. In some markets, the Transmission Planner is responsible for assessing future needs for transmission facility only. It does not have the authority to even suggest a corrective plan that involves generation improvement or DSM. The way R2 and its sub-requirements is written is more suited for an integrated planning process, which may not exist in some places/developed markets.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use “may include” instead of “including”. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Correction Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including~~			

Q16			
Commenter	**Yes**	**No**	**Comment**
~~Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
LADWP		☑	We should be very careful about using DSM as Corrective Action for transmission problem. What this would lead to is to have a "built-in" transmission problem which would require DSM as the de facto rolling brown-outs or black-outs. DSM should be part of the resource and load forecasting consideration; transmission planning should design tranmission that can properly serve the forecasted loads with the expected resources; not to "live with" or include transmission contraints that rely on DSM as a solution. If the industry truly wants to use DSM as mitigation for transmission deficiencies, let's do it as a deliberate action, not an unintended consequence. "System deficiencies" may be corrected with an integrated approach as suggested, but "transmission deficiencies" are solved by transmission improvement. The classic example is Path 15 in WSCC/WECC. The transmssion deficiency of PAth15 was well known for many years (like since '80s) and in the "pre-deregulated" dates, the deficiency was indeed managed by an integrated approach when the utility can operate its assets integrally. Then de-regulation happened and the integrated approach became unbundled and impossible resulted in numerous brown-outs and black-outs in California in 2000-01 until a third transmission line is added. Transmission deficiencies, if not mitigated, will significantly affect the accessibility to transmission services, a key concern of ferc 890. As for new technology, just how the SDT proposes to define what constitutes a new technology? And how to measure for compliance against such a requirement? Hopefully, this is just another case of overly prescriptive standard.
Response: DSM refers to reduction in net Load. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their correction action plan. New technologies include any technology that is not currently in general use, or is in the development stages, on the electric power system that helps improve efficiency (i.e. energy storage/production technologies, low sag conductors, solid state interrupters, etc.)			
Manitoba Hydro		☑	DSM and generation improvements should be removed from Requirement R2.7.1, as they should not be mandated by a NERC standard are not in the tool box of the transmission planner. DSM may already be in the load forecast and sensitivities to load forecast variations are included in near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of transmission planners mitigation plan. If the corrective plan is too expensive the load serving entity could consider DSM and revise their forecast in the next planning cycle.
MRO		☑	DSM should already be in the load forecast and sensitivities to the load forecast variations are included in the near term planning horizon sensitivity analysis. Additional DSM shouldn't be part of the transmission planner's corrective plan. Additional DSM can be considered in the next planning

Q16			
Commenter	**Yes**	**No**	**Comment**
			cycle.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
Southern Transm.		☑	It should not be a requirement that DSM be considered but DSM should be one of the allowable alternatives. The way the present standard is written, it is unclear whether "all" of the named items (except operating procedures with the "or" statement) are required to be considered or whether only one or more of the items need to be included. It is suggested that the following statement replace the word "including" in line two of R2.7.1: "that may include one or more of the following:". This should clarify that all of the items are not required to be in the action plan for compliance. It also is not clear what the phrase "including the duration of interim Operating Procedure" means. Does this mean how many years you would anticipate using the Operating Procedure or does it mean how long it takes to "repair" the cause of the outage that necessitated the use of the Operating Procedure? Assuming that the meaning is the second one, the requirement to document the "mean time to repair" is new and there does not seem to be a very useful purpose for this requirement. As long as the system performance standards are met and the system is prepared for the next outage, what is the purpose of recording and documenting the length of time that you anticpate it to take to fix the problem? This is variable at best and does not provide useful information.
Response: The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. If an entity can show that DSM is effective, the standard should not bar them from using it. Your first interpretaion is correct (how many years you expect to use the procedure). **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
TSGT		☑	DSM should not be considered except as a load forecast variable. Rather, the load forecast probability index should be prescribed (specific probability of exceedance)

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The use of DSM is optional. Requirement R2.7.1 has been modified based on your comments to use "may include" instead of "including". DSM refers to reduction in net load that could be used to compensate for a generation deficiency or to reduce transmission overloads. **R2.7.1** - ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			
AECI		☑	
LCRA		☑	
SaskPower		☑	
Seattle City		☑	
Response: Thank you for your response.			
AEP	☑		Consider requiring that problem contingencies be simulated on base case that models the lower load level that would result with the DSM implemented.
Response: The standard does allow for consideration of DSM which is effectively the situation you are describing.			
APPA	☑		This is a conditional Yes. The Resource Planner or Transmission Planner must provide assurance that the specific "Demand" reduction that is incorporated into the scenario analyses will actually be reduced through either customer action or direct load shedding by the Balancing Authority. This type of controllable "Demand" does exist, but it is rare that planners and operators actually have such resources in their portfolios to help with System Deficiencies.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
ITC	☑		DSM alternatives should focus on existing contractual relationships only. DSM is an alternative to "capacity solutions" and you have to give weight to how well you can count on it during capacity emergencies. Will the load be there to cut? How certain are you (contractually) that the load will be shed voluntarily when called upon to do so?
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			
KCPL	☑		Only for DSM that is contractually "firm" and which can demonstrate mitigation performance (comparable to generation resource) as related to the transmission system.
MEAG Power	☑		DSM should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is available for curtailment by the System Operator and without the option to buy through and remain in service.

Q16			
Commenter	**Yes**	**No**	**Comment**
Response: The use of DSM is optional. The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. If an entity can show that DSM is effective, the standard does not bar them from using it.			
NCEMC	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
Santee Cooper	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered controllable and quantifiable resource.
SERC EC PSS SERC RRS OPS SCE&G	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm.
TVA	☑		It should be included if it is a tool made available to the TP for this purpose, but only to the extent that it is considered firm. However, the standards should not determine which type of fix a utility should use to meet system requirements.
Response: The use of DSM is optional. If an entity can show that DSM is effective, the standard should not bar them from using it.			
ABB	☑		First of all, you are not exactly requiring that DSM be considered or analyzed. You have simply listed it as one of the possible solutions. And you should mention the possibility of "integrated plan" in the standard itself. Since DSM is simply optional, let the planners figure out themselves how to consider DSM.
Allegheny Power	☑		It should be included if there are specific mandated or approved DSM programs in place during the study period.
ATC	☑		
BCTC	☑		DSM should be a load reduction.
CAISO	☑		We agree to include DSM among a mix of solutions to a system problem. However, the difficulty is that DSM is unpredictable when needed. Another issue is how much DSM is actually under the control of the Transmission Operator.
City Utilities/Springfield	☑		Controllable demand that will be available to both the planner and operator must be well defined and readily available when called upon including operating procedures.
Dominion	☑		An appropriate level of DSM should be included in studies.
Duke Energy	☑		DSM should be carefully included based upon consideration of the particular DSM measures available and the uncertainty associated with each.
Entegra	☑		
Entergy	☑		DSM should be considered, but it should be done prudently and in accordance with the contracts that govern the specific DSM program and only in cases where the Transmission Owner has direct load control. Transmission Owners should be allowed to include UVLS and SPS systems as a part of their Corrective Action Plans.
ERCOT ISO	☑		

Q16			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		DSM should be directly controllable with accurate information as the the magnitude and location. System stability should not be dependent on the operation of DSM.
FPL FRCC	☑		If DSM is included as part of an integrated Corrective Action plan, then the impact of DSM should be included by specifying the location and expected quantity of DSM that will mitigate a system deficiency. The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Muscatine P&W	☑		We do not have DSM but I could see where it could be used to relieve overloads or low voltage.
PJM	☑	☑	Yes- DSM should be modeled consistent with how it is expected to be operated based on contractual/operating relationships.
Progress–Carolinas	☑		State regulatory requirements mandate that we consider DSM alternatives. The DSM contracts would have to adequately support the intended use.
Progress–Florida	☑		The use of DSM, whether exclusively or in conjunction with other measures, is an acceptable operating procedure for use in a Corrective Action Plan, as long as the Transmission Owner demonstrates availability and accuracy of DSM data and its viability as an operating procedure for each applicable scenario.
Tenaska	☑		While DSM may, or may not, be manually operated, it is critical to understand the impacts of DSM and whether different ways of implementing DSM are of value.
WPS	☑		The effect of DSM should be considered in corrective action plans to the extent that DSM can reduce overall load growth and change the timing of new transmission facilities.
Response: Thank you. DSM refers to reduction in net Load. The use of DSM is optional. If an entity can show that DSM is effective, the standard does not bar them from using it. The standard does allow for consideration of DSM but other factors may disallow the use of DSM as a corrective action. The amount and uncertainty of DSM needs to be justified by the entity when it is included in their Corrective Action Plan.			

17) Q17. Requirement R2.7.2: Such Corrective Action Plans shall "Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables". Should new studies, including the facilities comprising the Corrective Action Plan, be performed to assess System normal performance and Contingency response for conditions that previously resulted in the System deficiencies (without the planned additions) and also demonstrate that the changes would not result in inadvertent negative impacts on the System. If you "agree", please comment on how a study area should be determined.

Summary Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current, and/or past as appropriate, as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements.

The following requirement was deleted due to industry comments:

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~

Q17			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	A new study should not be required. The impact of "fix" should be evaluated as part of determining it as a viable solution.
Response: The SDT agrees with your comment and has revised the requirements to agree with your comment. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Ameren		☑	This proposed requirement is unnecessary and a waste of time. Keep in mind this is a planning assessment and not a facilities study. Further, such a requirement implies a distrust of the transmission planners to develop valid corrective action plans to meet the requirements of the TPL standard. For more complex system facility additions, it would be inconceivable that a Transmission Planner or Owner or Planning Coordinator would proceed without performing power flow simulations to determine the efficacy of the system addition. But these studies would be performed over time considering the best available information and latest standards performance requirements. The majority of transmission projects consist of the upgrading of terminal equipment or conductor on one or more branches. The only significant change that such upgrade work would produce in a power flow model would be that the branch ratings would change. It is not necessary to rerun power flow simulations for such cases, as it can be determined by inspection whether the upgrade

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Commenter	**Yes**	**No**	**Comment**
			work would be sufficient to move the facility rating above the expected normal or contingency flow.
Response: The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies are performed to support compliance and demonstrate that the requirements are met. The specific requirement to re-test has been removed. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ The SDT has removed the Requirement R2.7.2 but kept the orignal R2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).			
Dominion		☑	In the normal course of business, a planner out of necessity will need to check to see if the proposed improvements will actually fix the problem. The prospect of making a multi-million dollar mistake is sufficient incentive to insure this study occurs without the additional burden of creating an audit trail to meet a NERC standard. Requirements for what study area should be used and documentation of the process are not necessary. If, per chance, a study is not performed immediately, the next set of studies will show the deficiencies, if any.
Response: The intent is to ensure that for a specific problem the Corrective Action Plan is checked to the extent that the Corrective Action Plan does not cause any additional problems. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
E ON US		☑	Re-testing is part of the normal study process of developing the Corrective Action Plan (CAP). Most CAP should be developed in the Long-Term horizon. The next annual study and all subsequent studies provide sufficient review without developing another set of cases and additional testing in the initial assessment.
Response: The intent of the standard is to develop a Corrective Action Plan that will create a system capable of meeting system performance requirements. The intent of the standard is to provide verification at the time the Corrective Action Plan is developed and not wait a year to perform the verification. This is critical to ensure that plans are coordinated between entities. The SDT has removed the Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
Brazos Electric	☑		It is difficult to understand what is meant by 'retested'. The evaluation of a CAP includes testing the recommended option to see how it performs and to insure that it does not create other problems. We assume this is what is meant by retested. In our evaluation we insure that it does not negatively impact all other facilities in the BES and if so what extent and if it is managable. We do not always create a separate 'study area' each time for each system improvement.

Q17			
Commenter	**Yes**	**No**	**Comment**
CenterPoint	☑	☑	Many problems identified in future studies and associated transmission improvements are fictitious due to the speculative nature of predicting load and generation growth. Requiring exhaustive studies to determine the full impact of fictitious transmission projects is unnecessarily prescriptive and burdensome, and provides little, if any, value in identifying and solving real transmission problems.
CPS Energy		☑	Should be conducted for Near Term Planning Assessment only with the study area determined at the discretion of the Transmission Planners.
FPL FRCC		☑	Incremental benefits do not justify the magnitude of additional studies. Corrective Action plans should be tested, but not as a new study with all of the Corrective Action Plans included simultaneously. The proposed language is inferior to the existing language (TPL-002-0 R2) and suggest replacing with language from TPL-002-0 R2.
Georgia Transm.		☑	This is the essence of planning. All entities should ensure that Corrective Action Plans address the identified constraints and work within the BES infrastructure. It is not clear what the intent of "new" studies is. Since the evaluation of Corrective Action Plans is part of the planning process, what new studies is this requirement referring to. The determination of the study area should be by the Planner.
LADWP		☑	This is a redundant and unnecessary requirement. How can one come up with a corrective action plan if it has not been demonstrated the plan can mitigate the problem? And if the corrective plan has been able to demonstrate that it can mitigate the problem, why repeat the study again.
Manitoba Hydro	☑		At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan. Furthermore, corrective action plans should not be requierd to address issues raised by sensitivity studies. Corrective action plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the corrective action plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations.
MISO		☑	Sufficient analysis, including re-testing, must have been performed in creating the Corrective Action Plans. Requiring demonstration by the transmission planner that this is the basis of the Plans is superfluous.

Q17			
Commenter	**Yes**	**No**	**Comment**
MRO		☑	The MRO is concerned with this requirement particularly since the standard indicates that System Assessment shall be conducted each year while studies are not required each year. MRO members typically conduct this exercise at the time that studies are originally conducted with regard to improvements. By requiring a new study with improvements (some of which were justified in past studies) demonstrating that these improvements work essentially results in the Transmission Owner needing to clear a new unfair hurdle for improvements. This results in a requirement which will result in wide-spread non-compliance. The SDT should clarify that this requirement can be met by past studies. The MRO recommends that R2.7.2 be removed because it is redundant since development of the corrective action plan will have included these studies. At some point the corrective action plan should be tested to verify the plan meets the performance requirements. The way the standard is written is that the transmission plan should be perfect for the entire planning horizon for all sensitivities tested. Any issues should be immediately addressed. The standard does not allow any time to develop the corrective plan through an open and transparent process. Based on the Nerc definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. Standard R2.7 seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
PJM	☑	☑	Yes – At a minimum the system conditions and / or contingency that identified the system deficiency should be evaluated to determine that it has corrected the issue. The extent of the study area needs to be consistent with the size / complexity of the corrective action plan.
Progress–Florida		☑	Each Corrective Action Plan as stated in the original assessments should be trusted as effective, provided the Transmission Owner can demonstrate with its own internal assessments the effectiveness of each Corrective Action Plan.
Santee Cooper		☑	Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes. The majority of transmission projects consist of the upgrading of terminal equipement or conductor on one or more branches. The only significant change that such upgrade work would change in a powerflow model would be that of the branch (facility) ratings would change. It is not necessary to rerun powerflow simulations for such cases, as it can be determined by inspections whether the upgrade work would be sufficient to move the facility rating above the expected normal or contingency flow. We agree that the Planning process should ensure that corrective actions for a particular defeciency do not lead to other deficiencies. However, the process for ensuring this is not necessarly The

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Commenter	**Yes**	**No**	**Comment**
			development of new study cases which include facilities comprising the corrective action plan and the suscetesting is not needed.
Southern Transm.	☑	☑	A properly conducted study should determine that the recommended Corrective Action Plan actually solves the problem and does not cause other problems. If not, it is not a Corrective Action Plan. What appears to be intended here is whether the combination of Corrective Action Plans interact with each other and create additional problems. In the conference call Mr. Odom stated that it was not the intent for "all" the corrective plans be put back into the cases and all of the simulations be redone but only look at local area analysis. If that is the case, what is necessary to be in compliance with R2.7.2 and what type of documentation is required? This is very unclear. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes
WECC BPA TSGT TEP		☑	No, this is too onerous. We recognize that, when planning the system and developing a Corrective Action Plan, the transmission planner would have added the potential projects individually (or in small groups) into a case to re-test the system performance. Hoever, R2.7.2 seems to require that all potential projects be added back into the case simultaneously for retesting. There could be many different alternative solutions for each potential problem identified in the different study years without having the base solution first determined for a nearer term case. There can be many combinations of potential solutions for cases further into the future that satisfy the condition being studied. For example, a voltage problem can be solved by the addition of capacitors, completing a bus tie, adding a short line, operating procedure, changing generation dispatch, etc. Even assuming that one set of solutions are picked so the verification study can be performed, logistically this demonstration may be too close to the assessment in the following year. Instead of retesting the potential projects in the Corrective Action Plan on the original base case, it may be better to test them in the base cases prepared for following year's study. Any potential problem that is unresolved will show up again in the following year's assessment. Therefore, a separate demonstration using an "older" case may not be an efficient use of the TPs' and PAs' time and resources.
WPS	☑	☑	It is difficult to fully prescribe a methodology to define a "study area". It is most appropriate for the Transmission Planning to develop study areas based on and consistent with the transmission planning principles within Order 890.

Response: The intent of the standard is to develop a corrective action plan that will create a system capable of meeting system performance requirements. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. The SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans).

R2.7.2 ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
ABB	☑	☑	Any area where there might possibly be an impact. I.e., engineering judgement.
Muscatine P&W		☑	Large enough to ensure negative impacts will not occur. This could best be covered in regional studies. (See Q43 Comment #3)
Response: The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
AECI		☑	
SaskPower		☑	
Response: Thank you for your response.			
Alcoa	☑		NERC is revising the Transmission Planning Standards beginning with TPL-001. Alcoa agrees with NERC's approach to revising TPL-001 wherein NERC is consolidating duplicative Standards to promote consistent requirements of the planning process and thus improving reliability. Also, Alcoa agrees that new studies should not result in inadvertent negative impacts on the system especially when such studies have not taken into account the negative impact on an adjacent system. However, Alcoa believes that the current draft of the TPL fails to address FERC Order 890's requirements of an open and transparent Planning Process. Such a process provides Market Participants an equal opportunity for consideration in the Planning Assessments for contingency impact on transmission availability. (See FERC Order 890 ¶¶ 140, 207, 212, 323, 327, 337). Alcoa also believes that the current draft of the TPL fails to address and incorporate FERC Order 890's new requirement that transmission providers coordinate "…ATC calculations with their neighboring systems." For example, while Planning Assessments may indicate no NERC Compliance violations where the Table 1 and Table 2 Requirements are met, Market Participants are harmed and not provided protection from unequal treatment of their circumstance. This problem occurs when an analysis of a contingency event results in no IROL or SOL (all facilities remain within established ratings), but resultant transmission constraints cause reductions of ATC and subsequent market impact. As part of the System Planning Process, this is unacceptable, and, as a minimum, this type of situation must be included as a scenario reviewed in the required sensitivity analysis under the NERC TPL-001-1 Standard. The impact of such practices by large transmission providers on the ATC of smaller transmission

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Commenter	**Yes**	**No**	**Comment**
			providers can be significant. For instance, small transmission providers similar to Alcoa that operate non base-load resources such as hydropower, peaking units or wind power can easily see their ATC's reduced when sensitivity analyses are not performed under TPL-001-1. Alcoa believes that such sensitivity analyses should be a requirement. Alcoa believes that for consistency with the provisions of Order 890, NERC must re-visit not only the Planning Assessment implications on transmission availability but also couple this review with the revision of the NERC Modeling Data and Assessment Standards (MOD). Alcoa recommends that the MOD and TPL Standards be addressed in similar fashion to: 1) Incorporate the intent of Order 890 requirements of an "Open and transparent Regional Planning Process to provide non-discriminatory planning" for ALL Market Participants 2) Assure that the revised MOD and TPL Standards fully address implications of burdens on the Bulk Electric System (BES) related to transmission availability for contingencies in the Planning Process. FERC Order 890 ¶ 523 - Coordinate planning with interconnected systems. In addition to preparing a system plan for its own control area on an open and nondiscriminatory basis, each Transmission Provider will be required to coordinate with interconnected systems to (1) share system plans to ensure that they are simultaneously feasible and otherwise use consistent assumptions and data and (2) identify system enhancements that could relieve congestion or integrate new resources. (Emphasis added). 3) Sensitivity Analysis should include the potential impact on transmission availability and/or reductions in ATC on adjacent systems. Where ATC on an interface is reduced for a single contingency (N-1 planning, mitigation options must be provided). (This may require a threshold level of ATC reduction where a percentage reduction would be specified as acceptable on the N-1 basis, and a greater reduction than that threshold would be considered a Standard's Violation).
Response: The purpose of this standard is to develop corrective actions that can eliminate system performance deficiencies. The standard does not judge if the action listed is the only or the best action to be taken on an economic or market basis. It is the responsibility of the entity to resolve such issues and conform to FERC Order 890.			
AEP	☑		Consider limiting study area to immediately adjacent systems.
Allegheny Power	☑		Study area should be at least two buses beyond deficiency and plan elements.
BCTC	☑		The Assessment should state how the study area was determined, including input from adjacent Planning Coordinators. WECC has processes for coordination of planning information so that Planning Coordinators are informed of plans in other areas.

Q17			
Commenter	**Yes**	**No**	**Comment**
Entergy	☑		Study area should be determined on a case by case basis by the Transmission Planner. SEAMS agreements and other regional planning coordination activities should provide for adequate cooperation.
Exelon	☑		The study area should be at least the size of the original study area. Some engineering judgment is required to determine the subset of studies. Next year's study would include the full set of screenings for the future additions.
IESO	☑		We feel that having the requirement to retest the conditions which show a performance deficiency, but now with the proposed corrective measures, would suffice. To illustrate or require "how a study area should be determined" would be micro-managing, and the term "a study area" is not defined anywhere in the standard and is subject to different interpretation. For example, does it mean the physical area of study or does it mean the various areas in the study that need to be explored. We are therefore unable to offer any view as to "how a study area should be determined".
ITC	☑		Without further study once a “solution” has been proposed how can one be sure it will work and not create “other” issues? The area of study should be developed using good engineering judgment with input from any neighboring parties that might be impacted.
KCPL	☑		Corrective Action Plans taken by a transmission operator should not burden any of its' directly interconnected transmission operators. Study area should include at least all transmission operators directly interconnected to the transmission operator who took the initial corrective action. It may be appropriate to use the entire RTO/ISO/RRO as study area.
LCRA	☑		The question is not clear regarding "study area"; however, re-testing with corrective action / system improvement(s) in place is a must. The re-test must consider the same simulations that identified the initial deficiency. In addition, in the re-test, the action/ system improvement must be considered as a Planning Event itself (i.e., if the initial test showed a specific contingency causing a deficiency, then a physical connection of the system improvement to the identified contingency should be avoided or minimized - minimize the creation of Extreme Events.). In other words, planning solutions should be long-term and a system "fix" for the present should not result in a system problem in the foreseeable future.
MEAG Power	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes and should be allowed to choose the study area based on the prudent utility practice.
NCEMC	☑		Re-testing should be required particularly where the correction may impact network flows. The study area should be discussed within a stakeholder process to the TP may compile input from network customers or LSEs that might be affected by the analysis.
Northwestern Energy	☑		R2.7.2 does not refer to "how a study area should be determined". This added statement should be eliminated.
Progress–Carolinas	☑		There are separate regional processes for coordination with neighboring utilities.

Q17			
Commenter	**Yes**	**No**	**Comment**
ReliabilityFirst	☑		The study area should be determined by the Transmission Planner and Planning Coordinator.
Seattle City	☑		Sensitivity studies should be adequate to determine the study area. Starting at the corrective facility, work out bus by bus, determining sensitivity to the facility's loss. Boundaries of the study area would be defined at buses where loss sesitivity is (for example) 1% or less.
SERC EC PSS SERC RRS OPS SCE&G TVA	☑		Re-testing should be required only where the correction may impact network flows. The study area should be determined by the TP. The TP has the most knowledge of how the system responds to changes.
Tenaska	☑		The study area should be the same as in the original study unless the Corrective Action Plans require changes/additions outside of the original study area. If chagnes/additions are made outisde the original area, then the study area must be expanded to include, at a minimum, the area that includes the new changes/additions.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		The study area should be based upon planning expertise and knowledge of the system, giving due consideration to external impacts.
City Water Power and Light	☑		The system should be retested with new facilities in place to ensure that no new problems arise with the addition of new facilities.
Response: Based on industry comment, the SDT has removed Requirement R2.7.2 but kept the orignal 2.7.5 requirement, which was re-numbered as Requirement R2.7.3, (subsequent annual assessments report on the status of Corrective Action Plans). **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~			
FirstEnergy	☑		Although we agree with the concept of retesting, the standard should reference that a re-study is only required in the vicinity or portion of the system affected by new facility additions. Determination of the study area should be left to the Transmission Planner's judgment.
Response: The SDT has removed the specific requirement to perform re-testing with the understanding that the purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met. The standard assumes that the actions were developed and verified using the current and past studies that were used to uncover deficiencies and confirm adherence to the performance requirements. **R2.7.2** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance~~			

Q17			
Commenter	**Yes**	**No**	**Comment**
~~requirements in the tables~~			
NERC TIS	☑		All Corrective Action Plans should be tested on an interconnection-wide basis to screen for potential adverse impacts throughout the interconnection, not just the TOs area.
Response: Please see Requirement R8 for the coordination and peer review requirements.			
APPA	☑		This is necessary to insure the planners did not accidentally take the system and the future operation of the system from the frying pan into the fire.
ATC	☑		
City Utilities/Springfield	☑		Corrective action plans must be appropriately modeled in order to verify that implementing the plans results in a BES that will perform based on the applicable NERC Reliability Standards or more restrictive local area criteria.
Duke Energy	☑		New studies should be performed, but the study conditions should be determined based upon the judgment of the planner.
ERCOT ISO CAISO	☑		We agree that the system should be retested with the corrective measures to ensure that the defficiency has been cured and that there are no inadvertant negative impacts. Regarding Study Area, it is not a defined term, and it could vary depending on the size of the project or nature of the disturbance being evaluated.
New York ISO	☑		NYISO Agrees
Response: Thank you but due to the preponderance of industry response to this question, this requirement has been deleted.			

18) Q18. Requirement R2.7.3: The standard calls for a differentiation between committed and proposed projects. Do you agree that they should be treated separately? If not, please state why not.

Summary Response: Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4. A new Requirement R2.7.2 has been added. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q18			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand that there are differences between committed and proposed projects in an RTO environment where there is cost sharing for facility upgrades. From a NERC Standards compliance perspective, however, we do not see a need to differentiate between proposed and committed projects in the corrective action plan, as long as either properly addresses the required performance issue. We are not sure why there is a need to develop or maintain information on committed projects. This tracking is not needed to meet the existing TPL standards. Compliance requirements should be kept separate from administrative data requests. What is the perceived need to track committed projects that has not been presented here? Is this another example of distrust for transmission owners to build the proper facilities to create a more robust system?
Brazos Electric		☑	What is the difference? We assume committed means you have begun work on the project and can no longer stop. It would seem this would need to be defined more clearly and it is probably different for each project or entity. Why is this differentiation even needed?
Response: The SDT agrees with your comment that from a planning perspective, there is no benefit in trying to distinguish between "committed" and "proposed". Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and			

Q18			
Commenter	**Yes**	**No**	**Comment**
proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
AECI	☑		However, the question as to what is considered committed versus proposed. There are variuos step in the approval process for our company and we are not sure which approval would be considered committed.
AEP		☑	Consider adding clear definition of "proposed" and "committed" projects (definition may impact response to this question).
Allegheny Power	☑		There needs to be a clear definition developed for committed and proposed projects and those definitions need to be included in the definition section of the standard.
APPA	☑		While it is good to know the difference, it should be made clear in the Standard that if a project is listed as committed, it may be changed the next year to proposed project. Definitions for "committed" and "proposed" are needed to ensure consistent data/assumptions within each region.
BPA		☑	Support comments submitted by WECC. Also, one reason not to differentiate between committed and proposed projects is that regardless of whether a project is committed or not in a future case, the committment to implement a Corrective Action Plan becomes mandatory as time moves closer to the need date due to required system performance.
WECC TSGT TEP		☑	The definition of these terms can be vastly different across all TPs. How would this be effectively monitored for compliance with such different definitions? Also, each TO's criteria to go from a proposed project to a committed project can change over time due to other needs and requirements.
Central Maine Power National Grid New England ISO NU NPCC RCS NSTAR	☑		They should be viewed differently in the Near-Term. However, these should be defined terms.

Q18			
Commenter	**Yes**	**No**	**Comment**
United Illuminating			
City Utilities/Springfield	☑		Definitions of both “committed” and “proposed” are needed.
City Water Power and Light	☑		"Committed" and "proposed" projects need to be defined.
CPS Energy		☑	The treatment of each project should be at the dscretion of the Transmission Planners.
Duke Energy		☑	Even committed projects may not be built due to a variety of circumstances. Either type of project can be deferred or cancelled for a variety of reasons, including circumstances beyond the transmission planner's control.
Entergy	☑		Committed projects should be tested for effectiveness, however, the effectiveness of Proposed projects, as they are subject to change, should not require the same level of documentation as committed projects.
Georgia Transm.	☑		They are inherently treated differently. "Committed" projects are a part of the base assumptions in the base case, while "proposed" projects are evaluated until a point where corporate commitment has been made.
HQTE	☑		They should be viewed differently in the Near-Term.
E ON US		☑	MISO has spent years on trying to make a distinction. If this remains, then "Committed Project" must be defined.
ERCOT ISO CAISO		☑	The definition of "committed" projects varies from TP to TP. Also projects that are proposed today become committed in the planning horizon. Similarly, committed projects drop out due to variety of reasons. In terms of system studies, both committed and proposed projects are modeled and evaluated in the same system. How do we distinguish between the two?
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
FPL FRCC		☑	All projects should be called "Planned" projects. There is no distinction in a model between committed and proposed projects that would treat them differently. They are either in the model or not in the model. This sub-requirement does not follow the major requirement wording in R2.7 ".....Such plans shall:" The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the addtional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. Suggested wording for R2.7.1.1. “Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided (to whom?), and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements.”
IESO	☑	☑	Yes, the distinction should be made as committed projects have a higher degree of certainty to be available for the period under study, whereas a proposed project is one that is supported by the

Q18			
Commenter	**Yes**	**No**	**Comment**
			assessment but the commitment to proceed is not yet secured. However, we do not see the need (a) to establish criteria for committed projects and proposed projects, and (b) to distinguish between the criteria between them. If the standard should require a TP to assess both scenarios - with and without proposed projects, then this should be clearly stipulated.
ITC		☑	All projects should naturally become committed projects at some point prior to the need date. The time frame should be dependant on the scale and voltage class of the project.
LADWP		☑	Seems like every company would have its own definition of committed vs propsoed project.
Manitoba Hydro	☑		However, since each planner is allowed to define the criteria, there will be no consistency as to what is included in the base case models.
NCEMC	☑		Projects that are underway (i.e. being built) and are not subject to be potentially delayed and are absolutely needed for reliability should be differentiated between those that are not. Perhaps definitions for each of these terms should be considered for clarification.
NERC TIS	☑	☑	No concensus in TIS after extensive disucussion, but it will be discussed further.
Northwestern Energy		☑	No, there are no clear guidelines on how to make this distinction.
PJM	☑	☑	We agree that there needs to be a differentiation between committed and proposed projects. Proposed projects, particularly generation interconnections and their associated network upgrades need to be identified as a group so that they can be removed from cases if the proposed generation interconnection does not move forward.
Progress–Carolinas		☑	Are projects are proposed until they are completed.
Progress–Florida		☑	This differentiation is meaningless when modeling projects in cases for planning analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability.
Seattle City		☑	Since compliance with performance guidelines is mandated, aren't all projects defined in the corrective action plans "committed" projects? Proposed projects in the context of Requirement 2.7 should only exist in the studies to determine which remedial solution(s) comprise the Corrective Action Plan.
Southern Transm.		☑	This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".
WPS	☑	☑	If the standard makes a differentiation between "committed" and "proposed" projects, definitions for

Q18			
Commenter	**Yes**	**No**	**Comment**
			each, within the standard itself, are necessary. Within the context of R2.7, it is not clear what impact the differentiation between "committed" and "proposed" has on the requirement itself. R2.7 requires Corrective Action Plans to address deficiencies within the performance analysis of the events in Table 1 and Table 2. A fundamental underpinning of R2.7 should be that Corrective Action Plans are developed consistent with the transmission planning principles of Order 890.
Response: The SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
MEAG Power		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is not relevant.
Santee Cooper SERC EC PSS SERC RRS OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.3 should be deleted.
Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.			

Q18			
Commenter	**Yes**	**No**	**Comment**
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4**. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		Yes, it helps when considering other issues in the same area. You would know whether or not you can count on a project going in.
AECC	☑		not only should a distinction be made but committed projects should be further classified as committed and under construction. There is a difference between a project be committed and actually being built. This difference can be many years. It would also be nice to know projects that are in the conceptual stage. This allow other stakeholders to share their thoughts and collaborate on projects of mutual interest before a project reaches the committed stage. Once a project is committed it is very difficult to make modifications.
ATC	☑		
BCTC	☑		
Dominion	☑		
Entegra	☑		
Exelon	☑		
KCPL	☑		
LCRA	☑		
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
ReliabilityFirst	☑		
SaskPower	☑		
Tenaska	☑		
TVA	☑		

Q18			
Commenter	Yes	No	Comment
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed as indicated in the summary.			

19) Q19. Requirement R2.7.4: For such Corrective Action Plans "Committed projects shall not be removed without documentation to show that the revised plan meets the performance requirements". Do you agree or disagree with this requirement? If you disagree, please explain why.

Summary Response: Commenters generally agreed that "committed" plans are difficult to define and may have a different meaning for many entities. In addition, even considering the generally accepted understanding of what "committed" plans means would still lead to the fact that such plans could change up until the plan is actually implemented. Therefore the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and goes on to state what is intended by the word "actions".

The following requirements were changed due to industry comments:

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.
R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.
R2.7.3. ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~
R2.7.4. ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~

Q19			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	As stated above, we are not sure why there is a need to develop or maintain information on committed projects. This tracking is not required in the existing TPL standards. As long as the revised corrective action plan meets the reliability performance requirements, what difference does it make if a committed project is cancelled or changed to a proposed project from a compliance perspective? We need to keep compliance requirements separate from administrative data requests or survey responses.

Response: The SDT agrees with your comment and has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating~~

Q19			
Commenter	**Yes**	**No**	**Comment**
~~Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
Brazos Electric		☑	This seems like more documention is needed however if the new CAP analysis will suffice for documentation regarding removal of the 'committed project' then this is acceptable. However, that kind of makes having such a thing as a 'committed project' fairly useless if you can change it. This appears to just be more unnecessary documention.
Dominion		☑	We are of the opinion that committed projects could be removed without documentation. Once a project is removed, the next set of studies will show the deficiencies, if any.
Response: The SDT agrees with your comment that "committed" plans can change. The SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
E ON US		☑	Our planning process includes documentation of the need, acceleration, delay, or elimination of all projects. As worded, I do not need to document the delay of a Committed project.
Northwestern Energy		☑	Same problem as Q18; but it isn't clear what level of documentation is needed.
BPA		☑	See response to Q18.

Q19			
Commenter	**Yes**	**No**	**Comment**
CenterPoint		☑	This is overly prescriptive. Allow each Transmission Planner to determine the best way to handle planned projects.
CPS Energy		☑	The treatment of each project should be at the discretion of the Transmission Planners.
Duke Energy		☑	The annual assessment will show that the revised plan meets performance requirements.
FirstEnergy		☑	Unless there is an industry agreed upon distinction and definition between "committed" and "proposed" projects, we do not agree that they should be introduced in this standard.
Georgia Transm.		☑	See responses to Q17 and Q18.
KCPL		☑	Corrective Action Plans must demonstrate performance based on the expected system configuration. Committed projects can be changed or discontinued before completion.
LADWP		☑	All this does is create more bureaucratic tracking and paper pushing. People probably won't classify anything as committed until concrete has been poured just so not to have to deal with all these paperwork.
Manitoba Hydro		☑	The standard does not allow any time to develop a corrective plan through an open and transparent process. Based on the NERC definition, a Corrective Action Plan is the list of actions and an associated timetable for implementation to remedy a specific problem. A Corrective Action Plan could mean that load forecasts at the station will be verified, facility ratings verified and alternatives to fix the identified problem to be determined before the next Planning Assessment. This standard seems to be mixing the idea of a Corrective Action Plan with the original TPL idea of determining corrective plans to achieve required performance. A corrective plan wil be the end goal of a Corrective Action Plan.
MEAG Power		☑	See response to Q18.
MISO			The current Corrective Action Plan should show the performance of the system with the best information available. These Plans will change year by year as conditions change and new information becomes available. Requiring that Plan projects from previous years may not be modified "without documentation" adds a additional unneeded paperwork.
MRO		☑	The MRO disagrees with this requirement. This is an unnecessary requirement since each year Corrective Action Plans must meet the system performance requirements.
Santee Cooper SERC EC PSS SERC RRC OPS SCE&G		☑	The goal is to meet the system performance requirements outlined in the standard. Whether a project is proposed or committed is irrelevant. R2.7.4 should be deleted.
Southern Transm.		☑	See comments for Q18. [This requirement does not appear to have any major benefit, particularly coupled with R2.7.4 discussed in Q19. The standards require that an assessment be done every year and that the system must meet performance requirements or a Corrective Action Plan be developed. Therefore, if a project has been previously specified as a "committed" project, removing it and or replacing it with something else must also meet performance requirements under this

Q19			
Commenter	**Yes**	**No**	**Comment**
			standard or a violation occurs. Also, this performance of the system with the "committed" Corrective Action Plan" removed or modified must be documented. Therefore, requirement R2.7.4 is automatically met and is superfluous in the standard and should be removed. There is no benefit from the distinction between a project definition of "committed" and "proposed".]
Tenaska		☑	Add after the word "requirements" the following: "without the committed projects."
TSGT		☑	R2.7.4 calls for change monitoring. If documentation of changes is required, just say so. Do not restrict changes.
WECC TEP		☑	The requirement is similar to the question posed in Question 17. What is the documentation that proves this is needed?
SaskPower		☑	
BCTC	☑	☑	We have a larger concern. If a project is Committed and is proceeding with construction, why would a transmission planner not consider this is in planning studies. Showing that a committed project is not needed and removing it from the plans, does not necessarily remove it from the future system. In addition to showing that the revised plan meets the performance requirements, the planner needs to include documentation to show that the Committed project has been cancelled.
IESO	☑	☑	We agree that committed projects should not be removed from the revised plan. But we question the need for this sub-requirement which calls for: "Revisions to the Corrective Action Plans are allowed over time but shall meet the performance requirements.." Committed projects are normally included in the planning studies for which the performance is assessed. Deficiency, if identified, will have a corrective plans developed. We do not understand the need to remove or revise the committed plan in this context.
NERC TIS	☑	☑	Any revision to the Corrective Action Plan should be tested to ensure that the revised plan meets the precribed performance requirements. Documentation of that testing is appropriate.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		It is unclear as to what the commited project is being removed from. Suggested language "…removed from the plan…".
ERCOT ISO CAISO	☑		We agree that committed projects should not be removed from the revised plan. These are supposed to be included in the planning studies which determine the system performance in the first place. The definition of "committed" projects varies from TP to TP so this would require a standard definition.

Q19			
Commenter	**Yes**	**No**	**Comment**
Seattle City	☑		To agree with the comment in Q18, the requirement should read "Corrective Action Plans shall not be modified without documentation to show that the revised plan meets the performance requirements."
Response: Based on your comment and the comment of others that state that "committed" plans could change up until the plan is exercised, the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
FPL		☑	All projects should be called "Planned" projects. Additionally, see response to question 18.
FRCC		☑	See response to question 18.
Response: Although the comment suggests referring to all plans as "planned", the comment of others that stated that "committed" plans ("planned" in your case) could change up until the plan is exercised; the SDT has modified Requirement R2.7.1 and deleted the original Requirement R2.7.2 through Requirement R2.7.4 to require only the Corrective Action Plan and indicates what is intended by the word "actions". The SDT feels that documenting the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans. **R2.7.1.** ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. **R2.7.2.** ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list			

Q19			
Commenter	**Yes**	**No**	**Comment**
of actions developed in accordance with Requirement R2.7.1. **R2.7.3.** ~~Include documentation of the criteria for determining committed and proposed projects, with all projects identified as either, 'committed' or 'proposed.'~~ **R2.7.4.** ~~Not remove committed projects without documentation to show that the revised plan meets the performance requirements.~~			
ABB	☑		It's kind of obvious. If you require a solution to begin with, then if that solution is removed, another solution must be planned. However, if the removed project is not directly related to the study or problem at hand, then engineering judgment will be needed as to whether or not to repeat the study.
AECC	☑		It should also show the justification for the revision. This is especially true if transmission service is going to be sold using models that contain committed projects. If a plan is revised I would hope the revision would meet the performance requirements better than the project it replaces.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		It may be necessary, as a band-aid-type substitute, to replace a committed project with a Remedial Action Scheme (RAS)/Special Protection Systems in lieu of new facilities. Whatever the revised plan, it must be shown to meet the performance requirements.
ATC	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Entergy	☑		
Exelon	☑		
ITC	☑		We agree.
LCRA	☑		
Muscatine P&W	☑		
New York ISO	☑		NYISO Agrees
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		We always should be able to show that we meet performance requirements.

Q19			
Commenter	**Yes**	**No**	**Comment**
Progress–Florida	☑		
TVA	☑		
WPS	☑		As stated in response to Q18, it is unclear why the differentiation between "committed" and "proposed" is actually necessary. The standard must allow flexibility, so that the evolution of a Corrective Action Plan can occur within the context of the transmission planning principles of FERC Order 890.
Response: Thank you but due to the majority of industry response to this question, the requirements have been changed			

D) Performance Requirements

The proposed revised planning standard (TPL-001-1) incorporates a number of changes in requirements as compared to the current planning standards (TPL-001-0 through TPL-004-0), which it is expected to replace. Among other things these changes are intended to clarify the standard, address issues described by FERC, and, in particular, to "raise the bar." Strengthening the planning standards in selected areas is necessary to maintain a reliable Bulk Electric System that is up to the challenges of the 21st Century. In proposing the requirements in this draft, the standard drafting team attempted to balance the value of increased reliability against any potential increase in work and costs to meet the new proposed standard.

The standard drafting team is seeking input from the industry to determine whether a proper balance has been achieved. The areas where material changes are proposed in this draft are enumerated below, and questions are posed by the standard drafting team to obtain industry comment. In formulating your responses, please keep in mind that material changes in the final standard will be accompanied by a transition plan to provide for an orderly implementation of the final standard.

The performance requirements relative to Non-Consequential Loss of Load for the following events enumerated in the two tables can be considered more stringent than the existing TPL standards. Furthermore, the proposed standard is based on an assumption that performance requirements for EHV facilities should be more stringent than for lower voltage facilities.

Do you agree that Non-Consequential Loss of Load should not be permitted for the following events? If you disagree, please provide a reason for your disagreement.

20) Q20. P2-1: Loss of bus section (SLG for stability) above 300 kV

Summary Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. The SDT has also revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT did not feel that any change needed to be made to this requirement. Note: P2-1 from the original draft is now P2-2 in the revision.

Many of the responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response.

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
ABB			Loss of load is not usually considered by tranmission planners. In power flow studies, they look at flows and voltages versus limits. In stability studies, they are looking for angles, speeds, and voltages that stabilize at good values, possibly with temporary excursions less than some limits. How should all these be converted to a loss of load value? Normally we ensure no loss of load <because> we meet thermal, voltage, and stability requirements. Maybe you are saying that planners should not use load tripping as a solution for these violations?
Response: Tripping of Load can be used as an operating tool to maintain or restore a System to acceptable performance. The standard needs to quantify whether this action is acceptable from a planning perspective and, if so, then it needs to quantify the acceptable situations and limits. This second draft is proposing that no Non-Consequential Load may be tripped for the loss of a 300 kV (or higher) bus section for a first contingency event. (See Table 1)			
LADWP			There is a fundamental fatal flaw in having different reliability requirements using an arbitrary separation of the connected bulk electrical systems into above 300kV and below 300kV. The standard should be re-draft without this separation and comments be solicited at that time. These questions are fundamentally unfair without first settling whether or not it is wise to arbitrary separate the bulk system into two different classes. This is like asking someone "Did you hit your spouse today?"
Response: Draft 2 has been modified for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	Usually, this type of outage will not involve non-consequential load loss,

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			however, there may be specific situations where local non-consequential load loss could be justified. This is consistent with how transmission systems have been designed for many years and approved by State commissions. Transmission Owners need to have some flexibility to balance grid reliability vs. cost to the ratepayer. In some instances, the expense required to eliminate all local non-consequential load loss cannot always be justified if there is no significant improvement in wide area bulk power system reliability. In other words, making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries.
Response: The SDT agrees that typically systems are designed such that Non-Consequential Load won't be lost, which should minimize the exposure to non-compliance for most companies. The SDT agrees that the focus of the standard needs to be on network performance and has added greater detail to Tables 1 & 2 which address the comment. The standard is a planning document; so although the SDT agrees that operating the BES is an important issue, it is not the focus of this standard.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the system will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be the focus in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definition for Consequential and Non-Consequential Load Loss. Will agree subject to proposed revisions to definitions of Consequential and Non-Consequential Load loss.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss which should address your concerns.			
CAISO		☑	Loss of bus section is Category C for which the current NERC criteria allows controlled loss of load. The NERC system has been designed with this criteria. To create a more stringent standard would require to build hundreds of miles of new transmission lines to bring the existing system to NERC compliance. What are the potential benefits of this stringent criteria? Also, what is the

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			reasoning behind selecting 300 kV as a cut off level?
Tenaska		☑	May need to consider using 500 kV as some transmission providers serve load off of the 345 kV system which could be triggered by this event.
Response: It is not clear if the comment is referring to Consequential or Non-Consequential Load, but greater detail has been added to Tables 1 & 2, which should address your comment.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
MEAG Power		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
NCEMC	☑		Although this is a relatively low probability event, we do agree that it should be assessed given the widespread effects. It may not justify the need for a network upgrade but at least deserves consideration for an operating or corrective action procedure should the event occur. Also, given this analysis might be new for some TPs, consideration should be given to a transition period after the start of this type of assessment.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed.
SCE&G		☑	SCE&G does not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. If not allowed, unprecedented new transmission costs will be required. These costs will be for local area improvements and will NOT result in increased

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			transfer capabilities for markets.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
SERC EC DRS SERC EC PSS SERC RRS OPS		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures. The marginal increase in reliability for this low probability event does not justify the huge costs involved.
Response: To address your concern, the SDT will consider a transition policy as part of the implementation plan to allow for Transmission Owners to respond to requirements that involve raising the bar. The implementation plan will be developed for a subsequent posting. As a first step the SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential load.			
TEP		☑	R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. Load Specifications in R2.4 are ambiguous for the reasons stated above. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term “assessment” rather than “study”. For most people, “study” implies detailed modeling and simulation analyses summarized in a report, whereas “assessment” implies a reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: The SDT has made several changes to the referenced sections. The SDT agrees that “assessment” and “study” have different implications and reflected that in this revision.			
WECC BPA TSGT		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
			the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: It is not clear if the comment is referring to consequential or non-consequential load, but greater detail has been added to Tables 1 & 2, which provides for more situations where it is acceptable to lose load and may address part of the comment. The following response is provided to the issue raised relative to the 300 kV cut-off. Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response.			
WPS		☑	It is not clear why the standard has established 300 kV as the differentiation point between allowing non-consequential load loss and not allowing it. The standard has established different planning requirements for different voltage levels without establishing why the differentiation is necessary. While transmission facilities over 300 kV in some areas of the country may be considered the "backbone", it is not universally applicable; in some areas, 230 kV and even 138 kV represent the "backbone" of the transmission system. The standard should not bisect the transmission system and apply two different planning requirements without clearly establishing why the differentiation is necessary.

<table>
<tr><th colspan="4">Q20</th></tr>
<tr><th>Commenter</th><th>Agree</th><th>Disagree</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>Additionally, Table 1 needs to clarify the use of the term "Firm Transfers" and the interruption of "Firm Transfers" as an acceptable response to an event. "Firm transfers" is not a standard transmission service offering under the ProForma OATT. The standard must be consistent with service types defined under the ProForma OATT. Suggest that the phrasse "Firm Transfers" be replaced with "Firm Transmission Service consisting of Point-to-Point and Network Integration Transmission Service"</td></tr>
<tr><td colspan="4">Response: The following response is provided to the issue raised relative to the 300 kV cut-off.

Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions:

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below.

Please see also summary response.

With regards to ‘Firm Transfers’, ‘Firm Transmission Service’ is now referenced in the Tables.</td></tr>
<tr><td>Entergy</td><td>☑</td><td></td><td>Table 1 does not specify "SLG"</td></tr>
<tr><td>PJM</td><td>☑</td><td></td><td>Should be a 3 phase fault not a single line to ground fault.</td></tr>
<tr><td colspan="4">Response: The tables have been revised and Table 2 differentiates between SLG and 3 phase faults.</td></tr>
<tr><td>HQTE</td><td>☑</td><td></td><td>The term "bus section" needs to be clarified. Some examples should be given showing actual diagram of substation layout.</td></tr>
<tr><td colspan="4">Response: The SDT discussed the definition of a ‘bus section’, but elected not to include a definition or examples in the standard.</td></tr>
<tr><td>ITC</td><td>☑</td><td></td><td>Should also consider no or limited loss of load for facilities 100 kV and above.</td></tr>
<tr><td colspan="4">Response: ITC may elect to apply the greater than 300 kV requirement to Facilities greater than 100kV for their own use. However, the SDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.</td></tr>
<tr><td>Manitoba Hydro</td><td>☑</td><td></td><td>With the caveat that if the loss of load is localized, it is acceptable. Raising the bar will result in a cost increase for owners and users of the transmission system. What evidence does the SDT have to show this is justified.</td></tr>
</table>

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
Response: The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		Note to APPA members – Please examine closely and give us specific comments on Q20 – Q29. If you disagree we need to know.
ATC	☑		
Ameren	☑		No significant material change identified.
CenterPoint	☑		
Central Maine Power	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		
Entegra	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
E ON US	☑		
ERCOT ISO	☑		
FirstEnergy	☑		
Georgia Transm.	☑		No change from current standards.
IESO	☑		We agree, since the loss of a bus is a single contingency. This is a criterion already adopted by the IESO and other members in the NPCC region, for which non-consequential loss of load is not permitted.
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		

Q20			
Commenter	**Agree**	**Disagree**	**Comment**
MISO	☑		No indirect (non-consequential) loss of load for single contingency events, else operator is in SOL pre-contingency without such planning.
National Grid	☑		
NERC TIS	☑		Loss of a bus section is a single contingency. Non-consequential load loss should not be allowed.
New England ISO	☑		
New York ISO	☑		
NU	☑		
NPCC RCS	☑		
Nstar	☑		
PRPA	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SRP	☑		
United Illuminating	☑		
Response: Thank you.			

21) Q21. P5-1: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment[1] followed by loss of another Transmission circuit

Summary Response: Based on industry feedback, the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies (N-1-1) involving two Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See responses for Q43.			
Ameren		☑	Load pockets supplied by a single EHV substation with only two supplies would not meet this proposed requirement, whereas the existing TPL-003-0 standard would allow the dropping of load for the multiple outage event. A significant material change to build new facilities would be needed to meet the new requirement.
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
CenterPoint		☑	The forced outage of two independent lines has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Given the low probability of extended overlapping outages of overhead facilities, systems have been designed assuming that load shedding following the loss of a second transmission line is permissible. Eliminating any allowance for load shedding for this condition may require significant system expansion and cost to to customers. However, it would be reasonable to consider establishing an upper bound to the amount of load that could be shed for these purposes.
E ON US		☑	Outage of two 345 kV circuits can create local area issues that result in loss of load but do not affect the integrity of the BES.
ERCOT ISO CAISO		☑	This event falls under Category C for which controlled loss of load is allowed. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Georgia Transm.		☑	This requirement appears unreasonable for a network system and, particularly, for a series of events. This requirement would be well above current reliability standards. The requirement would also result in higher investment costs for the utilities.
MISO		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Santee Cooper		☑	We do not agree with the concept of non-consequential load loss. To maintain system reliability, the disconnect of any load should be allowed. By not allowing non-consequential load loss,

Q21			
Commenter	Agree	Disagree	Comment
			utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Seattle City		☑	Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements. Loss of two major HV elements can drive our region into undervoltage conditions, forcing us to shed non-consequential load per UVLS standard requirements.
SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Southern Transm.		☑	This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.
TVA		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to construct a transmission solution for some extremely low probability events with low consequence. Each utility should have the flexibility to base action on probability and consequence. Load shed by UVLS or other means should remain an option to maintain reliability if probability is extremely low, but the high consequence of an event determines that a solution is necessary.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load.			
Dominion		☑	See comment for Question 20 above.
Response: See response to question 20.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			requirement and to correct it would be costly.
Response: Consequential and Non-Consequential Load Loss involves Transmission System actions not customer equipment response to system performance, which in some cases may be within a tolerable system bandwidth, but not within the customer set points. The standard anticipates that the System will be designed to meet the expected Load, which implies that customer tripping of its own Load should not be a consideration in planning studies. This has been addressed in the definition of Consequential Load Loss.			
BCTC		☑	Do not agree based on SDT definitions. Also do not agree for first outage being a forced outage. Will agree subject to above revisions to definitions of Consequential and Non-Consequential Load loss for the first outage being a planned outage but not a forced outage. To meet this requirement for forced outages, estimate that this change could cost $3 to 5 Billion.
Response: The SDT has considered industry comments and has incorporated changes in the definition of Consequential Load Loss, which should address your concerns.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Response: The standard needs to provide some consistency and needs to define the desired level of System reliability, which will provide a level playing field and will provide guidance and support for the Transmission Planners as they deal with external entities.			
MEAG Power		☑	See Q20 above.
Response: See response to question 20.			
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load.
Response: The time the operators have will depend on their time dependent ratings that they have to work with. Many users have a 30 minute rating.			
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose load, which should reduce the increased cost exposure.			
Tenaska		☑	See comment in Q20.
Response: See response to question 20.			
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below. Please see also summary response. With regards to 'Firm Transfers', 'Firm Transmission Service' is now referenced in the Tables.			
WPS		☑	See response to Q20.
Response: See response to question 20.			
IESO	☑	☑	The sequence of events is too general that under some condition, it contradicts with the loss of 2 circuits on the same tower for which non-consequential loss of load is permitted. If the sequence of events is specified such that the two transmission circuits that can be lost are unrelated, then non-consequential loss of load should generally not be allowed following system adjustments after the loss of the first transmission circuit.
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed.			
ITC	☑		Should also consider no or limited loss of Non-consequential load for facilities 100 kV and above. This should be no loss for load levels where the TO would expect to perform system maintenance.
Response: ITC may elect to apply the greater than 300 kV requirement to facilities greater than 100kV for their own use. However, the ATFNSDT feels application to the greater than 300 kV is more appropriate for the requirements in this standard.			
New York ISO	☑		We are assuming the second circuit is un-related to the first. If that is not the intent then it contracts the loss of multiple related circuits (same tower or protection zone) for which non-consequential load loss is allowed.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.

Q21			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Utilities/Springfield	☑		
City Water Power and Light	☑		
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
National Grid	☑		
NERC TIS	☑		This becomes a differentiation between an event and a contingency - if there is time to adjust the system, it is really two events. Non-consequential load loss based on the first event is hard to fathom. Loss of load following the second event is either consequential to the second event (even if load was isolated by the first event) or non-consequential to the second event.
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

22) Q22. P5-2: For facilities above 300 kV, loss of a Transmission circuit followed by System adjustment followed by loss of a transformer with low side voltage rating above 300 kV

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions:

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more load but the system is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to SDT’s emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenter’s questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV transmission system.

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See response to Q20.			
E ON US		☑	Outage of two 345 kV circuit and a transformer can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response area for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21. We do not foresee any cost due to this standard at this time because we do not have any transformers with low side voltage rating above 300 kV.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for compliance?

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power United Illuminating		☑	Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in our new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages, such as typical line outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT appreciates your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the System to prepare for the second on the EHV System. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
NERC TIS	☑		See Q 21 Comment
New York ISO	☑		Same comment as with Q21.
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21, loss of elements of this size may initiate UVLS.
Response: See response to Q21.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
			loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criteria for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above. In this case, the first transmission may also remove a transformer from service if they are in the same protection zone. The next contingency can be the loss of the companion transformer, without a fault on the transformer itself but not on the transmission circuit. If the transmission circuit and the transformer are unrelated, then we would agree that non-consequential loss of load should not be allowed.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. We have adjusted our approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjustment verses the ratings utilized.
Response: Based on industry feedback, the SDT has made adjustments to the expected Transmission System performance to N-1-1 events. The entire BES is treated the same now for these outage scenarios and the loss of Non-Consequential Load is now permitted. Please refer to performance tables, Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: Non-Consequential Load Loss is not permitted for the first N-1 event as part of the permissible system adjustments that can be made to return the system to a “new” normal operating state. The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Following the loss of the second Transmission outage, Load shed is considered an allowable system			

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
adjustment action for the entire BES. This is a change in Draft 2 of the TPL-001-1. Please see performance tables, Planning Event P6 for additional information.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages. (Transformer outage could occur first).
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			
National Grid New England ISO NU NPCC RCS NSTAR	☑		Should also consider the initial loss of a transformer, followed by the loss of a Transmission circuit. This should state a transformer with a "high-side" rating above 300 kV.
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the performance table to clarify the EHV transformer versus other BES transformers.			
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: The SDT has adjusted the tables in the second revision.			
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
Georgia Transm.			Not applicable to our existing system.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		

Q22			
Commenter	**Agree**	**Disagree**	**Comment**
Entegra	☑		
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

23) Q23. P5-3: For facilities above 300 kV, loss of a transformer with low side voltage rating above 300 kV followed by System adjustment followed by loss of another transformer

Summary Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions:

Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6.

It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.

Why the distinction for above 300 kV Transmission?

The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more expensive ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems.

The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs.

Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission system.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: See Q43 response.			
NERC TIS			See Q 21 Comment
SRP		☑	Same as Q21.
Seattle City		☑	Same as Q21.
New York ISO	☑		Same comment as with Q21.
Response: See Q21 response.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
Tenaska		☑	See comment in Q20.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: See Q20 response.			
E ON US		☑	Outage of two 345 kV transformers can create local area issues that result in loss of load but do not affect the integrity of the BES.
Response: The condition you describe appears to be more stringent then the outage the SDT was asking industry to consider; N-1-1 involving a line and transformers where each are operated at a voltage level above 300 kV. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
Response: Please see the proposed Glossary Definition for Non-Consequential Load. The proposed definition for Consequential Load clarifies that losing a motor due to motor contactor action is considered to be the loss of Consequential Load.			
BCTC		☑	Same comments as for Q21/22. Furthermore, a double transformer loss forced outage has a very low probability as transformers are very reliable. A more practical approach would be to

Q23			
Commenter	Agree	Disagree	Comment
			use single phase transfomers and provide a spare phase.
CAISO		☑	This event also falls under Category C for which the current NERC criteria allows controlled loss of load. Clear net benefits should be demonstrated to justify adapting to a new stringent criteria.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level (such as 1000 MW) of non-consequential load that is acceptable for such low probability events.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Southern Transm.		☑	See comments for Q21. [This is a very significant change in the performance requirements in this reliability standard. It involves facilities from 345 kV through 764kV which carry significant amounts of power. These also are facilities that require significant lead time to construct in the Southern Balancing Authority with estimates up to 7-10 years in the state of Georgia. If a performance problem is detected under these new requirements, it could take that long to come into compliance and at a very significant cost if a new major 500kV line is required. These facilities can run as much as $4.0 million a mile or more in urban areas. We understand that a few areas of the country presently have this requirement but most do not. In the areas where the requirement has not been in place, the reliability of the system has been acceptable to the local Public Service Commissions that have governed the service to Retail customers. There has been no evidence presented that there is a need for an increase in reliability, particulary at the extensive time delay and expense possible from this particular requirement. An adoption of this standard without such evidence can only be considered arbitrary and capricious at best. Increased reliability is, in general, a worthy goal where it is cost effective. It may be appropriate to adopt this type of reliability requirement for areas that deem the resulting reliability increase to be cost effective for their customers. But it is inappropriate to "require" everyone else to be forced to live under this arbitrarily developed expansion of reliability requirements.]
WECC BPA TSGT TEP		☑	The Bulk Electric System has been developed without this requirement. Before making the entire NERC system adopt this more stringent Standard, the SDT needs to show or address the benefits of this more stringent requirement with the cost of adaptation. Compliance with this standard as proposed could require some utilities to add hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation. Cost of these new facilities would eventually be borne by the end-use customer. A cost benefit balance has been arrived at over many years time between the customers and the regulators. Also, how will existing systems be handled for

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			compliance? Is there a logical reason for the use of the 300kV cut-off level? We believe that this type of load shedding should be allowed for these conditions at any voltage level. In any case, consideration should also be taken on whether the non-consequential load loss is Interruptible load or firm demand.
ITC	☑		Should also consider no or limited loss of non-consequential load for facilities 100 kV and above. No loss should be allowed for load levels at which the TO would plan to perform maintenance. Also system adjustment should consider time required for adjust.ment verses the facility ratings utilized.
NCEMC	☑		We do agree that given the widespread effects of these facilities above 300 kV that these should be subjected to more rigorous assessments.
Progress–Carolinas	☑		It is absolutely necessary, however, to allow interruption of firm transfers as a System adjustment. To do otherwise would cause extremely large expenditures for very low probability independent events.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Duke Energy		☑	Allow indirect (Non-Consequential) loss of load for events involving short duration outages that do not result in cascading outages.
Response: The specific outage considered involves a circuit and a transformer. An unplanned EHV transformer outage will likely be a long duration outage that needs to be reviewed with other N-1 events and should require a higher level of expected reliability. However, based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
Response: Your concern related to increased cost is shared with others. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. See response to Q43.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
			contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: We appreciate your support that Non-Consequential Load dropping would not be permissible following the first Contingency event. However, from a planning viewpoint, the SDT also believes that it should not be permissible to drop Load as part of adjusting the system to prepare for the second on the EHV system. The FERC directed this approach in Order 693, see discussion in paragraphs 1782 and 1796. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
FPL FRCC		☑	Systems have been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition.
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages.
Response: The events considered are not simultaneous N-2, but intended to be N-1-1 with system adjustments allowed in between the outages. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
Central Maine Power National Grid New England ISO NU NSTAR		☑	This should state a transformer with a "high-side" rating above 300 kV.

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
United Illuminating			
Response: The SDT agrees that it previously missed the situation described and have accounted for this sequence of events in new Planning Event P6. Also, notes have been added to the bottom of the Performance table to clarify the EHV transformer versus other BES transformers.			
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information. The lower (non-peak) Load study that you reference is a good suggestion that could be adopted as an internal company criterion for assessing maintenance flexibility.			
IESO	☑	☑	Similar reason as above.
Response: The intent of this event is to cover two unrelated single Contingency Transmission outages that are non-generator outages. They are to be viewed as an N-1, with system adjustments, followed by the second N-1. The standard will require that Contingency events be modeled to reflect actual removal of all elements within the protection zone. Therefore a single (N-1) Contingency could result in multiple Facilities being removed from service. The N-1-1 event should accurately reflect all Facilities that would be removed from service. Based on industry feedback the SDT has made changes in proposed requirements for two independent overlapping single Contingencies involving two Transmission Facilities operated at a voltage level above 300 kV. The SDT has adjusted its approach to two independent overlapping single Contingencies (N-1-1) involving two non-generator related outages and now permit the loss of Non-Consequential Load to meet the Transmission performance requirements; see Performance Table Planning Event P6. See the above Summary Response for additional information.			
AEP	☑		Consider adding clear definition of "system adjustments", including the amount of time permited to implement prior to the loss of the second facility.
Response: The time permitted is based on the time dependent emergency Facility Ratings of the affected Transmission equipment. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.			
MISO	☑		Do not allow indirect (Non-Consequential) loss of load for events involving long duration outages, such as transformer outages.
Response: While some SDT members agree with your approach, others on the SDT do not as well many of the industry comments to our Draft 1 standard. The standard does require sensitivity studies and unavailability of long lead time Facilities to be included in the sensitivity study area. Additionally, a TO will be required to notify their PC for long-term Transmission outages with consideration to spare equipment strategy. This would result in a new initial study system (N-0) and performance requirements for other Contingencies would be required subsequent to the long-term outage item.			

Q23			
Commenter	**Agree**	**Disagree**	**Comment**
Ameren			No opinion as we do not have any transformers with the low side voltages rated above 300 kV. Transmission owners with transformers meeting this requirement should be consulted to determine if a material change would be required.
ERCOT ISO			We will comment on this at a later date.
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
Georgia Transm.	☑		Not applicable to our existing system.
HQTE	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
Manitoba Hydro	☑		
NPCC RCS	☑		
PJM	☑		
Response: Thank you but due to the majority of industry response to this question, the requirement has been changed			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

24) Q24. Loss of non-bus tie breaker (above 300 kV) due to internal fault

Summary Response: A majority of the commenters indicated that a definition for "bus-tie breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for bus–tie breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. However, the SDT felt that this was one situation where the bar should be raised and no change was made to this event.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Manitoba Hydro			Until the SDT should defines a non-bus tie breaker this is impossible to answer.
ERCOT ISO CAISO		☑	Same response as for Q21, and What is the definition of non-bus tie breaker? Doesn't it just refer to line, transformer, and generation breakers?
Response: The SDT has accordingly proposed a definition for bus-tie breaker.			
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS		☑	See response to Q20.
Response: Please see response to Q20.			
E ON US		☑	EHV station configurations are either ring-bus or breaker and one-half. Breaker failure protection isolates two EHV Facilites which may cause local area issues without affecting the BES.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Duke Energy		☑	Depends upon the definition of non-bus tie breaker. By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers for low probability events. See comments to Q43.
FPL FRCC		☑	This loss is currently distinguished from other single contingencies because of its lower probability of occurrence and a more stringent performance requirement than currently exists is not warranted.
Progress–Florida		☑	This single contingency event has a very low probability of occurrence, and thus a more stringent performance requirement than currently exists is not warranted.
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-bus tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability period. System is already planned to meet this requirement based on the first sentence of footnote (b).
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
steady state performance requirements.			
CenterPoint		☑	The loss of a non-bus tie breaker due to an internal fault has a low probability of occurrence and should be considered an improbable event with non-consequential load loss permitted. However, the loss of any breaker, whether by internal fault, external flashover, or stuck breaker, should not result in a cascading failure.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
PJM	☑		Agree with performance requirement. The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Exelon		☑	P6 allows for non-consequential load loss for a bus tie breaker, which has the same probability of failure as a non-bus tie breaker.
Response: In Draft 1, P6 is for loss of Bus-tie Breaker below 300 kV. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Georgia Transm.		☑	The standard needs to clearly define a non-bus tie breaker. It is also not clear whether the focus of the standard is the kV level or the equipment type. A material change to build new facilities would be needed to meet this new requirement.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
LADWP		☑	Don't understand why there is such an obsession with bus tie breakers? Is this a common practice in the East? I am not aware of any issue in WECC, let alone at above 300 kV systems.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new Facilties. This initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering contingencies of two EHV Facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Seattle City		☑	Adequacy of HV supply is outside of our control but may have a detrimental effect on our system. We should not be required to supplement the existing high-voltage infrastructure when it is the

<table>
<tr><th colspan="4">Q24</th></tr>
<tr><th>Commenter</th><th>Agree</th><th>Disagree</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>responsibility of the transmission owner. If the intent of this requirement is to prevent downstream load loss caused by a fault in the 300kV beloning to the transmission owner, then we agree. We must be able to shed load when our supply is cut.</td></tr>
<tr><td colspan="4">Response: The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.</td></tr>
<tr><td>Santee Cooper
SERC EC DRS
SERC EC PSS
SERC RRS OPS
SCE&G
Southern Transm.</td><td></td><td>☑</td><td>By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost. It would be helpful if "bus tie breaker" was defined (e.g. is the middle breaker in a breaker and a half scheme considered a bus tie breaker?).</td></tr>
<tr><td colspan="4">Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.

The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load’s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.</td></tr>
<tr><td>Tenaska</td><td></td><td>☑</td><td>Why should we distinquish between a bustie breaker and a non-bus tie breaker? Also, 300 kV may be too low. This is really an issue that should be driven by the customers.</td></tr>
<tr><td>ABB</td><td>☑</td><td>☑</td><td>When talking about breaker outages, I see no reason to differentiate between "non-bus tie" and "bus tie" breakers. Are bus tie breakers inherently more reliable? If the effect on the system due to a tie breaker outage is very bad, then this should be fixed. All other contingencies seem to be slotted based on probability. Shouldn't breakers? Maybe bus tie breakers are weak points in the transmission system that need to be improved.</td></tr>
<tr><td>Central Maine Power
HQTE
National Grid
New England ISO
NU
NPCC RCS
NSTAR</td><td>☑</td><td></td><td>It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.</td></tr>
</table>

Q24

Commenter	Agree	Disagree	Comment
United Illuminating			
ITC	☑		Loss of non-consequential load should not be permitted, however this should also apply to other breakers across the system including bus tie breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses.			
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of a non-bus tie breaker (above 300 kV). Losing a non-bus tie breaker could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. Losing a breaker due to an internal fault is a low probability event. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of large number of transmission facilities with the attendant environmental impacts and increased cost to customers
Response: The SDT will consider interim Operating Procedures to allow for Transmission Owners to respond and guidelines that may allow quantifiable and limited exposure to loss of Non-Consequential Load. This may include, for example, providing for defined exclusions during construction of new facilties.			
Ameren	☑	☑	This part of the proposed standard language is confusing. From our perspective, the failure of any 300 kV or above non-bus-tie circuit breaker should not result in the non-consequential loss of load. Further, EHV circuit breakers failing as a result of internal faults are extremely rare, bus-ties or not. Also, it is not clear what would be considered a non-bus tie breaker for ring bus and breaker-and-a-half bus configurations. It would seem that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Response: Depending on the bus configuration loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers is to encourage the installation of Bus-tie Breakers in straight busses. In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: In response to industry comments, the SDT has accordingly proposed a definition for Bus-tie Breaker.			

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
FirstEnergy	☑		The tables' use of internal faults and stuck breaker faults is confusing since they have the same result.
Response: The probability of loss of a breaker due to the breaker internal fault would be higher than loss of a Transmission element coupled with a stuck breaker associated with the faulted element. Tables 1 and 2 have been modified to provide greater clarity.			
NERC TIS	☑		By its very nature, the event described is a breaker failure and the fault will typically need to be cleared by the next set of breakers, often remotely. Tripping out to the backup protection breakers typically can cause significant Consequential load loss. That should not be misconstrued as non-consequential load loss. Non-consequential load loss beyond that is unacceptable.
Response: Whether tripping of additional Facilities by backup protection will lead to more Consequential Load Loss will depend on whether any Load is connected directly to such Facilities. In the second draft the SDT has modified the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
IESO	☑		Agree. In general, non-consequential loss of load should not be permitted for any single contingencies.
Entegra	☑		
ISO/RTO	☑		
KCPL	☑		No Non-Consequential loss of load for N-1 event.

Q24			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
MISO	☑		No indirect (Non-Consequential) loss of load for outage of single EHV element.
New York ISO	☑		
NCEMC	☑		See response for Q20.
Progress–Carolinas	☑		
Response: Thank you.			

The proposed standard is based on an assumption that performance requirements for non-bus tie EHV breakers should be distinguished from other breakers and that performance requirements for EHV facilities should be more stringent than for lower voltage facilities. Do you agree that Non-Consequential Loss of Load should not be permitted for this event?

25) Q25. P3-1: Loss of (SLG for stability) either a generator, a Transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV)

Summary Response: A majority of the commenters indicated that a definition for "Bus-tie Breaker" as well as clarification of the Tables is needed. Based on the comments from the industry, the drafting team has proposed a definition for Bus–tie Breakers, incorporated changes to the definition of Consequential Load and added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load. The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Question 43 #5.			
Ameren		☑	The loss of two or more elements at any EHV substation at time of peak would likely result in loss of non-consequential load. If the intent of the proposed standard is to encourage the development of ring bus or breaker-and-a-half bus arrangements at the EHV level, we would concur where it is physically possible and makes for good engineering practice. However, we must remind the SDT that there are some existing facilities that cannot be converted practically or economically from their present straight bus configuration because of physical limitations. A significant material change, potentially several million dollars per substation, would be required to retrofit facilities, where possible. It would appear that performance requirements for EHV bus-tie breakers (and not non-bus-tie breakers) should be distinguished from other breakers.
Duke Energy		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence.
Entergy		☑	N-1-1 requires an increase in investment that will place an undue cost burden on all customers

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			for low probability events. See comments to Q43..
SaskPower		☑	The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Santee Cooper SERC EC DRS SERC EC PSS SERC RRS OPS SCE&G Southern Transm.		☑	By not allowing non-consequential load loss, utilities will incur significant expenditures to solve a problem with an extremely low probability of occurrence. The benefit will not justify the cost.
Northwestern Energy		☑	Non-consequential load loss should be permitted for this contingency.
Response: Based on industry feedback the SDT has made changes in Draft 2 on requirements related to two independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. However, it is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV facilities due to one Event. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Please see also summary response to Q22.			
Dominion		☑	See comment for Question 20 above.
MEAG Power		☑	See Q20 above.
TVA		☑	See Q20.
WPS			See response to Q20.
NCEMC	☑		See response for Q20.
Response: Please see response to Q20.			
E ON US		☑	This event needs to be reworded. Does the stuck non-bus tie breaker condition only apply to the bus fault or to all faults? Does (above 300 kV) only apply to the stuck non-bus tie breaker or is this limited to faults on facilities above 300 kV?
Response: The stuck non-Bus tie Breaker condition applies to all faults listed in P3 in Tables 1 and 2. The ATFNSDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose non-consequential firm load.			
ERCOT ISO CAISO		☑	Do not agree for loss of a bus, or loss of a stuck non-bus tie breaker for the reasons as in the response to Q21.
Response: Please see response to Q21.			
BCTC		☑	Do not agree due to definitions of Consequential and Non-Consequential Load Loss. Can agree subject to the proposed revised definitions to address loss of load during the transient stability

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			period. System is already planned to meet this requirement based on the first sentence of footnote (b).
MISO	☑		With the clarification that direct (Consequential) loss of load is associated with all outage elements: both SLG element and stuck breaker element.
Response: The drafting team has considered industry comments and has incorporated changes in the definition of Consequential Load Loss. **Consequential Load Loss:** Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.			
CenterPoint		☑	The loss of either a generator, a Transmission ciruict, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV) has a low probability of occurrence and should be considered an extreme event with non-consequential load loss permitted.
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
FirstEnergy		☑	The wording of P3-1 is unclear. We suggest rewording to say "Fault on a generator, line, transformer, or bus and a stuck breaker when the fault is being cleared". We agree with the concept of not dropping load for an EHV stuck breaker with the exception of the bus fault item. We do not believe that it is very realistic to postulate a bus fault along with a stuck breaker and believe that it is a very low probability event.
Response: The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Non-Consequential Load.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	It is unclear why bus tie breakers are being treated differently than other breakers. They should be treated the same.
Response: For straight buses, loss of a Bus-tie Breaker could remove from service multiple bus sections simultaneously resulting in loss of all elements connecting to the impacted bus sections. However, Bus-tie Breakers also have lower probability of outage. The reason for providing performance requirements for Bus-tie Breakers that are different from the performance requirements for non-Bus-tie Breakers so as to encourage the installation of Bus-tie Breakers in straight busses.			
FPL		☑	Systems have been designed such that Multiple Contingency events (N-2) above 300 kV may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis. In

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			addition, by not allowing loss of non-consequential load, the system may remain in a less secure state or condition. This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
FRCC		☑	This new category P3-1 is essentially a replacement for Category C5-9 except the only protection element failure to be considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate which in many cases has a more serious impact on grid reliability.
Response: The SDT has added greater detail to Tables 1 & 2, which provides separately for events that involve stuck breakers and protection system failure.			
Georgia Transm.		☑	A material change to build new facilities would be needed to meet this new requirement.
MRO		☑	This is a low probability event that could have significant impact on the system which historically have been designed to allow local load dropping including non-consequential load. The SDT should justify that the benefit to customers of this increased reliability justifies the cost of this change to customers. Alternatively, the SDT should define a level of non-consequential load that is acceptable for such low probability events such as 1000 MW.
WECC BPA TSGT TEP		☑	We disagree that non-consequential loss of load should not be permitted for this contingency event. We believe that planned and controlled interruption of non-consequential load should be permitted for loss of either a generator, a transmission circuit, a transformer, or a bus and a stuck non-bus tie breaker (above 300 kV). This contingency event could result in simultaneous loss of two or more elements, depending on the bus configuration. Allowing planned and controlled disconnection of some load in the areas would not only prevent cascading and instability (which could result in uncontrolled loss of a larger amount of load), but also enables faster load restoration. These contingencies are low-probability events. To meet this requirement as proposed would require severe pre-contingency curtailment of power transfers, that could impact commerce and/or construction of a large number of transmission facilities with the attendant environmental impacts and increased cost to customers.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments.			
LADWP		☑	Ditto (24)
Seattle City		☑	As in Q24. Certain combinations in the HV supply system will force us to shed load.
NERC TIS	☑		See comment to Q24.
Response: Please see response to Q24.			
Manitoba Hydro		☑	The SDT seems fixated on loss of load. The existing std for this type of event allowed for loss of load and firm transfer could be adjusted. While MH could rationalize that load should not be

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			interrupted, we could not agree that firm transfer can not be reduced. This would amount to n-2 planning to maintain a firm transfer that is backed up by reserves. The requirement to maintain firm transfer will cost MH and the industry millions of dollars with no reliability benefit - a show stopper.
Tenaska		☑	This is really an issue that should be driven by the customers.
Exelon	☑	☑	We do not agree with disallowing non-consequential load loss for these scenarios for the peak load conditions. These are very low probability contingencies, and some non-consequential load loss should be allowed at peak load. We would agree that it would be reasonable to dis-allow non-consequential load loss for these contingencies at a lower load level, such as 75% of peak load.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service.			
Progress–Carolinas		☑	This is a very low probability multiple contingency and would cost an extreme sum of money to remedy. Need to clarify whether or not the stuck breaker was connected with loss of element.
Response: The SDT has re-categorized the table to try to clarify what was meant but no changes have been made to this requirement as a result of industry comments. The SDT has added greater detail to Tables 1 & 2 to provide more clarity.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Furthermore, the greater-than-300 kV Bulk Electric System has been designed such that Multiple Contingency events (N-2) may result in Planned/Controlled Loss of Demand or Curtailed Firm Transfers. Such Non-Consequential Load Loss should be assessed for severity on a risk vs. consequence basis, placing particular importance on confining the event to a single area (i.e., not resulting in a cascading outage). Past assessments as well as actual events have demonstrated that by not allowing loss of non-consequential load, the Bulk Electric System may actually remain in a less secure state or condition, i.e. in more danger of experiencing cascading outages. In addition, it should be noted that the technical specifications of this category contain a major oversight. This new Category P3-1 is essentially a replacement for the existing Categories C5-9, except that the only protection element failure being considered is the failure of a circuit breaker to open. This definition eliminates the need to examine failure of the relay to operate, which in many cases has a more serious impact on grid reliability.
Response: The SDT must address FERC Order 693. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and Non-Consequential Load is being used as a proxy for firm Transmission service. The SDT has added greater detail to Tables 1 & 2, which provides for events that involve stuck breakers and protection system failure.			
ABB	☑	☑	Table 1 P3 is a little hard to read/understand. The second column should start out something like "A stuck breaker following the outage of any 1 of the following:" However, P3 will be completely redundant with P2 because, in power flow analysis, there is no difference between a breaker internal fault and a stuck breaker following an external fault. The final outaged equipment is the

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
			same. This will cause extra unnecessary work.
Response: The SDT has added greater detail to Tables 1 & 2.			
AEP	☑		Consider adding clear definition of "bus tie breaker" and "non-bus tie breaker".
Response: The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
ITC	☑		Should also consider no loss of non-consequential load for facilities 100 kV and above and this should also apply to other breakers across the system including bus tie breakers.
Response: The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering single events that can result in Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Loss of Facilities below 300 kV is not expected to have the same impact. Please see also summary response to Q22.			
AECC	☑		neither should consequential load be lost for any n-1 faults on the 300 kv system and higher.
AECI	☑		
Allegheny Power	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
Entegra	☑		
IESO	☑		See reason stated for Q24, above.
ISO/RTO	☑		
KCPL	☑		Must recognize that there may be Consequential loss of load.

Q25			
Commenter	**Agree**	**Disagree**	**Comment**
LCRA	☑		
New York ISO	☑		
PJM	☑		
Response: Thank you.			

The proposed standard is based on an assumption that the following events are relatively high probability events and, therefore, Non-Consequential Loss of Load should not be permitted. Do you agree? If you disagree, please provide a reason for your disagreement.

26) Q26. P4-1: Loss of a Generator followed by System adjustment[2] followed by loss of another Generator

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see Q43 #5 response.			
City Utilities/Springfield			Would like to see more explanation for the these scenarios.
ABB	☑		For Table 1 P4, rewrite it to read "Loss of a generator followed by a System adjustment followed by the loss of any one of the following: 1. Generator 2. Transmission Circuit 3. Transformer 4. A shunt device

[2] System adjustment can be manual or automatic

<table>
<tr><th colspan="4">Q26</th></tr>
<tr><th>Commenter</th><th>Agree</th><th>Disagree</th><th>Comment</th></tr>
<tr><td></td><td></td><td></td><td>5. Single pole of DC line."

This structure is easier to read and understand. The order should be like this to match P1. Shunt devices should be included.

P3 should be structured similarly.</td></tr>
<tr><td colspan="4">Response: The SDT has changed the performance table and language to clarify the specific scenarios. The SDT will be seeking comments on the new performance table.</td></tr>
<tr><td>Brazos Electric</td><td></td><td>☑</td><td>Need a definition of generator. The entire train, largest unit at a site or other.</td></tr>
<tr><td colspan="4">Response: The SDT has made changes to the performance table and language to define what is included in an individual generator outage.</td></tr>
<tr><td>Northwestern Energy</td><td></td><td>☑</td><td>What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.</td></tr>
<tr><td colspan="4">Response: The SDT has revised the proposed definition of Consequential Load Loss in the second draft. Per the SDT proposed definition, losing a motor due to motor contactor action is not considered Non-Consequential or Consequential Loss of Load. The SDT has made changes to the definition of Consequential Load Loss to clarify how this incident is to be treated with regard to system performance.

Consequential Load Loss: Load that is no longer <s>served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation </s>connected to a source as a result of the event being studied or which is lost as a result of the load’s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

With regard to the comment on cost, this requirement is consistent with FERC Order No. 693 and the SDT believes this is a more probable event than other events and therefore, the System should be designed per this requirement.</td></tr>
<tr><td>BCTC</td><td></td><td>☑</td><td>Do not agree due to the definition for Consequential Load Loss. Definition needs to include local networks for this contingency to be acceptable.</td></tr>
<tr><td colspan="4">Response: See responses to Question 2 and 6.</td></tr>
<tr><td>CenterPoint</td><td></td><td>☑</td><td>CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.</td></tr>
<tr><td colspan="4">Response: The majority of commenters in response to the first posting of the draft standard agreed with this approach.

With regard to the commenter’s second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC’s direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are beyond the scope of the SDT. The majority of commenters in response to the first posting of</td></tr>
</table>

Q26			
Commenter	Agree	Disagree	Comment
the draft standard agreed with this approach. See also the SDT's summary response.			
Central Maine Power New England ISO NU NPCC RCS NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of 2 additional generators.
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of 2 additional generators.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
LADWP		☑	This is N-2 and load loss should be permitted. As for whether or not this is a high probability event, there should be an objective measure (such as 1 in 5, 1 in 50, or 1 in 100, etc.) as to what constitute high probability, i.e., are there any outage history that would support any of the contention here that these are high probablity events? It is a mistake to arbitrary injecting "subjective" probability into a deterministic based reliability standard unless the industry is ready to move into 100% probabilistic based reliability standards.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an			

Q26			
Commenter	Agree	Disagree	Comment
appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
Response: The SDT notes that in Order 693 FERC directs NERC to prohibit Non-Consequential loss of Load for a single Contingency in the planning horizon whether it is to meet the System performance after the outage or to prepare for the next Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response. The SDT notes that when operating the System, the System Operator may have to drop Non-Consequential loss of Load as a last resort to maintain the reliability of the interconnected network. This would typically be for operating situations with more than a single prior outage for the Contingency event.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration. Specifically, the sudden loss of a large generator followed soon thereafter by the loss of a second generator would often result in such a large generation-to-load mismatch that Non-Consequential Loss of Load would be inevitable. It is clear, however, that the Bulk Electric System should be planned such that any generator can be maintained (offline) and the system can be operated to the contingency of another generator. This is accomplished in the Security Constrained unit commitment process. However, if the intent of this requirement is that the system should be planned such that there can be no Non-Consequential Load Loss for the loss of a second generator (after System adjustment), then the requirement is too stringent in that the planner would essentially have to plan for 3 generator contingencies. Finally, the probability of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
SRP		☑	The time to adjust the system needs to be provided (when does a N-1-1 become a N-2?). If the cause of the outage is transient (temporary) the operator needs some time to test and restore the element (could be minutes up to several hours). If the element is lost indefinitly, the operator will need some minimum time to adjust the system. If this time is not available prior to the next N-1 then the standard should allow Non-Consequetial Loss of Load. Some distinction needs to be made the amount of generation connected at a single point on the BES. a wind farm might have many small generators connected to the BES with an aggregate total of 300Mw or more. This requirement will should only apply to generating sources that might be connected to the BES through a single transformer (i.e. wind farm) with minimum agregate total of 300 MW (for N-1).
Response: The SDT believes that the time to adjust that is used in planning needs to be consistent with the time periods for which the Facility Ratings are designed. This time to adjust is different for different types of Facilities, as well as, for individual Facilities. The SDT has clarified this point in the standard but does not provide a specific time to be used for planning across NERC. The SDT has made changes to the performance table and language to define what is included in an individual generator outage. Treatment of wind farm in modeling and analysis needs to be addressed in MOD-010 through MOD-013.			
Santee Cooper		☑	The event should be tested for ensuring or maintaining reliability of the BES, however direct load loss should be allowed.
SERC RRS OPS TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
SCE&G		☑	Planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative facilities which shows that the probability of an event involving one generator outage followed by another generator outage is higher than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
Response: The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the Standard Drafting Team and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Tenaska	☑		This is really an issue that should be driven by the customers
Response: FERC Order No. 693 and the Energy Policy Act of 2005 has driven changes embodied by this question.			

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of 2 additional generators.
Response: FERC Order 693 indicates that only Consequential Load Loss should be allowed while Non-Consequential Load loss should not. See also the SDT's summary response.			
IESO	☑		The loss of a generator is different from the loss of a transmission facility. The former usually does not result in changes to the system topology nor system operating limits. While loss of 2 generators may result in resource deficiency, the decision to shed load would only be made when operating reserve cannot be replenished after the first contingency, and when the second contingency would result in violation of any SOLs or IROLs or BAL standards for which adjustment cannot be made within the required time line.
Response: The SDT agrees with the comment, although that is not the reason for the proposed changes. FERC Order 693 indicates that only consequential load loss should be allowed while non-consequential load loss should not. See also the SDT's summary response.			
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Response: The SDT agrees and has proposed changes to the tables to clarify.			
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a huge cost with minimal reliability benefit. A further comment is what rationale was applied by the SDT to come up with these combinations of events? is there a statistical basis? the viable combinations of multiple contingency events should be left to the experience of the transmission planner.
Response: FERC Order 693 indicates that firm transfers are not to be curtailed either to meet the System performance for a single Contingency or to prepare for the next Contingency. This is the basis for not allowing firm transfer. See also the SDT's summary response and Order 693, Paragraph 1796 for additional FERC clarification with regard to prohibiting curtailment of firm transfers after a single Contingency. The combinations of events were chosen drawing on the experience of members of the SDT. If there are any additional events that should be added to the tables, please provide specific suggestions during the next comment period.			
NCEMC	☑		In the case of generating capacity replacement, some guidance as to allowable system adjustments might be needed for clarification. Is calling on contingency reserves from a Reserve Sharing Group immediately prior to internal redispatch of available resources OK? What about Network Customer generation not at maximum output but available for redispatch ? What about transmission reconfiguration, cutting firm purchases (pro-rata or in entirety) acceptable?
Response: The SDT agrees with the comment and the SDT has proposed changes to clarify what System adjustments are allowed.			
WPS	☑		It is inappropriate to rely on Non-consequential loss of load as an ultimate Corrective Action Plan for this event. However, non-consequential load loss can provide interim relief until such time as the Corrective Action Plan is actually constructed and in-service.
Response: The SDT agrees with this comment and has proposed an interim relief provision for the standard.			
Ameren	☑		The outage of any two generators should not result in any non-consequential loss of load.

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
APS			
BPA	☑		
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
E ON US	☑		
ERCOT ISO CAISO	☑		Non consequential loss of load should not be permitted for this type of event. Loss of a generator has higher probability and longer duration than many other contingencies. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		

Q26			
Commenter	**Agree**	**Disagree**	**Comment**
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
Response: Thank you.			

27) Q27. P4-2: Loss of a generator followed by a System adjustment followed by the loss of a monopolar DC line

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is stated in paragraph 1795 of FERC Order No. 693 as follows: "Based on the record before us, we believe that the transmission planning Reliability Standard should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." Paragraph 1795 also states, "Therefore, the ERO should modify the sentence to indicate that manual system adjustments, except for shedding firm load or curtailment of firm transfers, are permitted after the first contingency to bring the system back to a normal operating state." These statements which indicate that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency are meant to apply to Facilities covered by reliability standards regardless of voltage, economics, or rate recovery issues.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the outage of another generator is higher than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of another generator. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Issues of cost recovery are beyond the scope of the standard.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a monopolar DC line
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
IESO	☑		Same reason as above except in this case, the loss of a monopolar dc line could interrupt import. Again, it is a resource issue, not a transmission reliability issue.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits agains the significant increase in cost that will be required.

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
			See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, the SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and therefore the SDT believes that this is an appropriate requirement for the standard. FERC's direction is meant to apply to BES Facilities covered by reliability standards regardless of land-use, voltage, economics, or rate recovery issues. Issues of land-use, economics, and cost recovery are not to be addressed by the SDT as being beyond the scope of the SDT. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. The SDT notes that in Order 693 FERC directs NERC to prohibit loss of Non-Consequential firm Load for a single Contingency and			

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
therefore the SDT believes that this is an appropriate requirement for the standard. The majority of commenters in response to the first posting of the draft standard agreed with this approach. See also the SDT's summary response.			
MRO	☑		The monopolar DC line words should be revised to "a single pole of a DC line".
Response: The SDT agrees and has made appropriate changes to the tables.			
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a monopolar DC line
Response: See summary response.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		AECI
Allegheny Power	☑		Allegheny Power
AEP	☑		AEP
APPA	☑		APPA
ATC	☑		ATC
BPA	☑		BPA
Brazos Electric	☑		
City Water Power and Light	☑		
Dominion	☑		Although we do not have any DC lines, Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Agree that non consequential loss of load should not be permitted due to higher probability of generator outage.
Exelon	☑		
Georgia Transm.	☑		

Q27			
Commenter	**Agree**	**Disagree**	**Comment**
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
NERC TIS	☑		
New York ISO	☑		
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

28) Q28. P4-3: Loss of a generator followed by System adjustment followed by loss of a Transmission circuit

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. Also see summary response to question 26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a Transmission line is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a Transmission line. Issues of land-use, economics, and cost recovery are beyond the scope of the standard.

The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	Need definition of system adjustment.
Response: The SDT agrees that system adjustment needed to be clarified. The SDT has made clarifying changes to the tables.			
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a Transmission circuit
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
			clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
SaskPower		☑	Local area network load is allowed to be shed in Saskatchewan. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability. The SDT should justify that the benefit to customers of this increased reliability justifies the cost.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit.
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: See response to #26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful balancing of the potential benefits against the significant increase in cost that will be required. See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
JEA		☑	I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years or seasons of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the facility emergency ratings and load shedding is limited to TP's contracted or tariff loads.
Response: SDT agrees that sufficient time must be provided for transition and will provide for that in the implementation plan for the standard. With regard to other comments, see summary response.			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this type of event.
Response: The SDT agrees that the draft standard could reasonably be interpreted that if a major generating outage lasts more than 1 year that the System still needs to be able to meet G-1, System adjustment and then, a 2nd G-1 without the loss of any Non-Consequential Load. This interpretation would require new construction to meet any G-1 + G-1 + G-1, because there would be a violation of the standard if any plant outage occurred and was not available over the peak period during the planning horizon. The SDT believes this is beyond most present planning across NERC. Therefore, the SDT has made a change to the proposed standard to develop a new requirement to replace R1.4 in the modeling section. The new requirement will be to perform the tests outlined in the performance requirements table and demonstrate that thermal and voltage limits are met, however, all manual and/or automatic actions are allowed (within time constrained ratings) including curtailing firm transfers and controlled shedding of Non-Consequential firm Load. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a Transmission line is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see the summary response with regard to FERC Order No. 693.			
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event			

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
IESO	☑		Similar reason as above. In this case, while the second contingency is the loss of a transmission circuit, the first contingency (loss of a generator) has not changed the system topology. Hence, the system condition after having been adjusted following the first contingency should in essence be similar to the all transmission facilities in service condition for which the non-consequential loss of load performance for single contingencies is expected.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a Transmission circuit
Response: Please see response to Q27.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
CAISO	☑		Same reason as in Q26.
City Water Power and Light	☑		
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
Duke Energy	☑		
Entegra	☑		

Q28			
Commenter	**Agree**	**Disagree**	**Comment**
E ON US	☑		
ERCOT ISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

29) Q29. P4-4: Loss of a generator followed by System adjustment followed by loss of a transformer

Summary Response: The SDT notes that FERC's direction with regard to Non-Consequential firm Load and the TPL standards is provided in paragraph 1795 of FERC Order No. 693 which indicates that loss of Non-Consequential firm Load and interruption of firm Transmission service should not be permitted for a single Contingency regardless of voltage, economics, or rate recovery issues. See summary response to Q26.

These events are on higher voltage facilities on the BES. The probability of the outage of one generator followed by the loss of a transformer is within an order of magnitude of a single Transmission line outage. Therefore, the SDT has drafted the standard to not permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a generator followed by System adjustment followed by the loss of a transformer. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: Please see response to Q43 #5.			
Brazos Electric		☑	See above.
Northwestern Energy		☑	What is non-consequential load loss? Is losing a motor due to motor contactor action a non-consequential load loss? Also, the transmission system was developed under criteria without this requirement and to correct it would be costly.
BCTC		☑	Similar to Q26.
Central Maine Power New England ISO NU NSTAR United Illuminating		☑	If the base case or a mandatory sensitivity case already includes unplanned generator outages, some load loss may be reasonable following the subsequent loss of an additional generators and a transformer
National Grid		☑	If mitigation plans are required that are based on studies that already include unplanned generator outages, then some load loss may be reasonable following the subsequent loss of an additional generator and a transformer
FirstEnergy		☑	Shedding load could be part of the system adjustment in preparation for the next possible contingency but load drop would not be acceptable for problems caused soley by the first contingency.
FPL FRCC		☑	Systems should be planned such that the loss of a generator, followed by System adjustment, followed by the loss of another generator would not result in Non-consequential Load Loss, and equipment ratings would not be exceeded etc. However, the initial state of the system must be clarified in all performance table scenarios (including P4-1).If the Base Case contained known planned outages of generating units, as implied by the requirement R1.4, then the standard performance requirements could be interpreted to require planning for all G-1-1-1 events.

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
JEA		☑	See comment on P4-3.
LADWP		☑	Ditto (26)
SRP		☑	Same as Q26.
Santee Cooper SERC RRS OPS		☑	Same comment as question #26.
HQTE	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer.
IESO	☑		Similar reason as above.
ITC	☑		Also use of system adjustment should consider time required to complete adjustment. Ability for generation adjustment should include the time required for unit startup if applicable.
Manitoba Hydro	☑		With the caveat that firm transfer is included in the adjustment, otherwise there is a hugh cost with minimal reliability benefit.
Tenaska	☑		This is really an issue that should be driven by the customers
Response: Please see response to Q26.			
CenterPoint		☑	CenterPoint Energy believes the assumption that this is a high probability event is incorrect. Furthermore, an absolute requirement prohibiting non-consequential loss of load has economic and landowner impacts that cannot be ignored.
Response: The SDT disagrees with the commenter's first statement. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response.			
CPS Energy		☑	Should be determined at the discretion of the Transmission Planners.
Entergy		☑	This would require an increase in investment that will place an undue cost burden on all customers for low probability events. It does not appear that there has been any meaningful blancing of the potential benefits against the significant increase in cost that will be required See comments to Q43.
Response: The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a transformer is within an order of magnitude of an event involving a single Transmission line. With regard to the commenter's second comment, see summary response			
Progress–Florida		☑	The severity of this event is such that Non-Consequential Loss of Load might be a necessary operating procedure in a Corrective Action Plan as part of System restoration, provided that the Non-Consequential Loss of Load is confined to a single control area (i.e., not resulting in a cascading outage). Furthermore, the frequency of an event should not be the primary factor determining whether or not Non-Consequential Loss of Load is permitted, but rather the presence or absence of cascading for the event. Existing Category C requirements are adequate for this

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
			type of event.
NPCC RCS	☑		Load curtailment may need to be implemented during system adjustment to ensure reliability for the next contingency and may be reasonable following the subsequent loss of an additional generator and a transformer
Response: Please see response to Q27.			
SCE&G		☑	Planned load loss should be allowed.
TVA		☑	It is agreed that this event should be tested for maintaining reliability of the BES, however planned load loss should be allowed.
Response: The SDT agrees that Consequential (direct) Load Loss should be allowed but disagrees that planned loss of Non-Consequential firm Load should be allowed. The standard has been drafted to allow Consequential direct Load Loss for this event but not Non-Consequential Load Loss for this Contingency event. The SDT has outage data for representative Facilities which show that the probability of an event involving one generator outage followed by a DC line outage is within an order of magnitude than an event involving a single Transmission line. Also, see the summary response with regard to FERC Order No. 693.			
Duke Energy	☑		Table in TPL-001-1 doesn't include the last part of P4-4 (low side voltage rating above 300 kV). We assume the inclusion of 300kV here in the comment form is in error.
Response: The SDT notes that the original comment form was in error as described in your comment. The SDT noticed the error and revised the comment form and reposted it to correct the error.			
MISO	☑		Note - No voltage limit for generator and transformer per Table 1, P4-4
KCPL	☑		Need voltage limit in Table 1.
Response: The SDT disagrees because voltage limits differ from system to system.			
ABB	☑		
Ameren	☑		The outage of a generator and any other element should not result in any non-consequential loss of load.
AECC	☑		neither should consequential load be lost. The system should operate to all performance criteria for loss of any one generator station (all units).
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
BPA	☑		
City Water Power and Light	☑		

Q29			
Commenter	**Agree**	**Disagree**	**Comment**
Dominion	☑		Dominion agrees with these proposed standards as they are relatively higher probability events and reflect very closely to the Company's internal planning criteria.
E ON US	☑		
Entegra	☑		
ERCOT ISO CAISO	☑		Same reason as in Q26.
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
MEAG Power	☑		
MRO	☑		
NERC TIS	☑		
New York ISO	☑		
NCEMC	☑		See reply to Q26.
PJM	☑		
Progress–Carolinas	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
Southern Transm.	☑		See comment for Q26 [These are relatively higher probability events and the increase in performance requirements is justified.
WECC TSGT TEP	☑		We agree that Non-Consequential Loss of Load should not be permitted. Loss of a generator has higher probability and longer duration than other contingency events. Overlapping outage of a second element while one generator is already out of service and system adjusted would likewise have higher probability than other multiple contingency events.
WPS	☑		See response to Q26.
Response: Thank you.			

The performance requirement for the following event may be considered less stringent than the existing TPL Standards — P2-3: Loss of a single pole of a DC line. Interruption of firm transactions (without Loss of firm Load) if the transaction is dependent on the faulted DC line is now allowed for this initiating event/Contingency.

30) Q30. Do you agree that interruption of any firm transfers that are dependent on the outaged DC line that is taken out of service should be permitted?

Summary Response: Some commenters that agreed with curtailing firm transfers that are dependent on a DC line when the DC line is outaged indicated that such curtailment should apply to AC lines as well. Also, some of these parties indicated concern that other transfers such as interruptible transfers should be also allowed. The SDT did not make a change in response to these comments because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Muscatine P&W			See Q43 Comment #5.
Response: The SDT does not see how Muscatine Power and Water's Comment #5 to Q43 relates to this question. The SDT does not make any change to the standard with regard to Q30 as a result of this comment.			
Ameren		☑	If the system cannot withstand the outage of the single element (AC or DC) without curtailment of the transfer, then the transaction should not be considered as firm.
AECC		☑	
BCTC		☑	Disagree with this unless AC lines are treated the same. There should be no distinction between AC and DC lines.
Duke Energy		☑	DC and AC line contingencies should have the same requirements.
Entergy	☑	☑	Why are only DC lines exempt for this requirement? Consider exemptions for AC transmission elements as well.
FPL		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system, therefore, AC lines should have the same performance criteria as DC lines.
FRCC		☑	DC and AC lines should not be treated differently. System response is similar for the loss of an AC line versus the loss of a parallel connected DC tie. For the loss of a parallel DC tie the transfer is shifted to the parallel AC system in the same manner as a loss of an AC line. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Therefore, AC lines should have the same performance criteria as DC lines.
Progress–Carolinas		☑	DC and AC lines should be treated comparably.

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
Santee Cooper		☑	AC and DC contingency events should be treated the same.
SaskPower	☑		Why is this concept not applied to AC tie-lines between systems, whether single or multiple? In Saskatchewan's case there is very little difference.
SERC EC DRS		☑	DC and AC contingency events should be treated the same.
SERC RRS OPS		☑	DC and AC contingency events should be treated the same. The question is somewhat obscure.
SCE&G		☑	General there should be no difference between AC and DC; however, the answer to this question depends on the contractual arrangements associated with the transfer.
Southern Transm.		☑	Why should the reliability level for a transaction on a DC line be different from a transaction over AC? Also, when the transfer over DC is removed, the load it was serving still has to be picked up in the AC network because load cannot be dropped. Therefore, this places a burden on the AC network to serve additional load. If you allow transfers over DC to be interrupted, you should also allow the interruption of transfers over AC for the same events.
LADWP		☑	If the transfer is on a line experiencing outage, then the transfer is interrupted. Whether or not the transfer is firm is immaterial. Whether or not it is on the dc or ac line is also immaterial.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		This should also apply to firm transfers via single or double ac facilities as well. In either case, the transfer could be linked to dedicated facilities.
ITC	☑		However, the owners of the firm transfers may not agree. If they don't, a system impact study needs to be part of the assessment IF THE OWNERS OF THE FIRM TRANSFERS DO NOT AGREE. It must be clear to the original TSR requester that this was truly conditional on the DC line being in service. If it was granted without telling them this, then the interruption of firm transfers should NOT be permitted.
TVA	☑		There are also conditions where this interruption should be allowed for a single AC tie line.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged.			
IESO		☑	Whether or not interruption of firm transfers should be allowed is more a business arrangement issue than a transmission reliability issue. Usually, delivery over a DC line, either as an import or access to internal or external resources, is factored into the resource integration plan to support meeting demand and energy transfers. The commitment for firm transfers may be made on the reliance of this delivery. However, the contingent loss of any resources including import is assessed in determining the amount and terms of firm transfers to a third part. This is a business

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
			and resource allocation issue, not a transmission reliability issue.
Response: While it is true that there are business issues associated with the subject of this question, the SDT disagrees with the commenter with regard to the relevance for reliability. How firm transfers will be treated in the standard will have significant impact on Transmission System reliability across NERC. The SDT has not directly made any changes to the standard as a result of this comment but has considered this comment in deciding how to proceed with firm transfers in the standard.			
Progress–Florida		☑	The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements.
Response: The SDT deleted the reference to asynchronous DC ties in the tables.			
WECC BPA TSGT TEP	☑	☑	We agree with the question asked. In addition, transactions that can be interrupted due to the loss of a DC line should not be limited to the firm transactions, that are dependent on the DC line. It should also include interruptible transactions and other transactions made available through negotiated agreements on both AC and DC lines.
Response: The SDT did not make a change in response to your comment because many of the transfers over DC lines are automatically curtailed when the DC line is outaged and because the ability to interrupt other transfers such as non-firm transfers are already provided for in the standard.			
Manitoba Hydro	☑		MH agrees that reduction of firm transfer to readjust the system after a contingency should be allowed for all events. The requirement to maintain firm transfer is a more stringent requirement that in the existing standard. The need to maintain firm transfer amounts to N-2 planning with no reliability benefit. Reduction in firm transfer is not equivalent to loss of load as the transfer is backed up by reserves. MH could not accept a standard mandating that firm transfer can not be interrupted. MH also recommends P2-3 be moved into the P1 bucket as loss of a single pole of a dc line is similar to loss of a generator or transmission circuit.
Response: The SDT does not agree with your first comment on the need to allow reduction of firm transfer for all events since changes have been made to the standard to comply with FERC Order No. 693 which does not allow curtailment of firm transfer or dropping Non-Consequential Load for single Contingencies. The SDT agrees with your second comment and has made the change in the tables.			
MRO	☑		The MRO questions why interruptions of firm transfers are not allowed in other cases since load dropping is allowed for these cases.
Response: The SDT did not make a change in response to your comment because the ability to interrupt other transactions, such as interruptibles, is already provided for in the standard.			
ABB	☑		Yes, this is the purpose of HVDC. It carries the power your want, no more, no less. Both the good and bad of parallel flows are avoided.
Brazos Electric	☑		

Q30			
Commenter	**Agree**	**Disagree**	**Comment**
City Water Power and Light	☑		
Dominion			Not applicable since Dominion has no DC lines.
E ON US			No opinion, we do not operate DC.
ERCOT ISO CAISO	☑		In addition, the interruptible and other negotiated transactions should also be allowed.
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
Exelon	☑		
FirstEnergy	☑		
ISO/RTO	☑		
KCPL	☑		"Firm" capacity dependent on DC line is similar reliability as a generator.
MISO	☑		The key word in this question is "dependent". Transfer is "firm" if DC line is in service.
NERC TIS			TIS will discuss this in further review of the standards development.
New York ISO	☑		NYISO agrees from a reliability aspect.
NCEMC	☑		Not applicable.
PJM	☑		
Seattle City	☑		Otherwise, we need reserve transfer capacity equal to the total of the firm transfers, which is not very cost effective!
Tenaska	☑		
WPS	☑		
Response: Thank you.			

E) Stability

31) Q31. The proposed standard is based on an assumption that steady state analysis and stability analysis are different from each other and that therefore, two tables of Contingencies and performance requirements were needed. It is also based on an assumption that stability study requirements should be clearly separated from the steady state study requirements. Do you agree with the action taken in separating stability analysis from steady state analysis? If not, please explain.

Summary Response: Some respondents thought that the Contingencies are the same for steady state and Stability or should be made the same with only one table. Some respondents thought that having two tables was confusing while others thought it improved clarity. The large majority agreed that separating Stability from steady state was the appropriate approach. The SDT will continue to have Stability and steady state analysis separate with two tables.

Q31			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	We understand the need to clarify the different requirements in the steady- state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
Response: The Contingencies are different in the extreme category. Therefore, it will be less clear to have only one table which includes both. The SDT decided to keep two tables.			
BCTC		☑	Disagree with the assumption that steady state and stability analysis are different and should be separated. There are only minor differences between the tables and the reasons are not apparent. The separate tables appear to be unnecessary and is confusing, especially the same contingency numbering for both tables. Any contingency that must be studied in the stability period should also be considered in the post transient steady state period. Request that the SDT provide an explanation of their assumption.
FPL		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
FRCC		☑	There are two points of view for this question. One view is that having the performance requirement for steady state and dynamics on two separate tables is a good idea. It makes it easier to identify the performance requirements for steady state and dynamics. The other view is that separation of these requirements into two tables is not necessary because the existing tables are clear and FERC Order 693 only required the footnotes to be clarified not to redevelop the tables. The structure of existing Table 1 reinforces the requirement for grid stability and maintaining the grid within

Q31			
Commenter	**Yes**	**No**	**Comment**
			applicable limits.
HQTE		☑	The contingency studied are the same and as a result should be combined into one table. Only the performance might be different. We understand the need to clarify the different requirements in the steady state vs. the stability analyses. However, for each contingency category we expect to see both the steady-state requirements and the corresponding stability requirements in the same table. We believe that it would be better to recombine the steady-state and stability tables and present the information in a landscape format.
LADWP			There is no vote needed here because even under the current standards, the performance requirements for steady state and stability are clearly separated. So what is being added?
IESO	☑	☑	We agree that the performance requirements for steady state analysis differ from those for stability analysis, but not the contingency requirements. While the specification of, for example, a line to ground fault on a single facility does not mean much to a steady state analysis, and in fact the loss of a single facility is all that it matters, the system is subject to the same type of contingency regardless of the type of analysis to be performed and hence the same contingency needs to be tested in both steady-state and dynamic simulations.
Response: The SDT decided to separate steady state from Stability because the models used in the two analyses are different and the Contingencies required are different. Therefore, the SDT decided to keep two tables.			
FirstEnergy		☑	While we agree that steady-state and stability are different situations, in general we believe that the tables are confusing, overly worded, and should be combined. The initiating events are the same regardless of steady-state or stability so there should be no reason not to combine the tables as was done in the previous standards.
Response: The initiating events are different in the extreme category. Therefore, it will be less clear to have only one table. The SDT decided to keep two tables.			
New England ISO		☑	Only the difference between steady-state and stability analysis should be the performance requirements. The list of contingencies should be identical regardless of the type of analysis.
NPCC RCS		☑	The contingency studied are the same and as a result should be combined into one table.
Manitoba Hydro	☑		Yes but the definition of contingencies in table 1 and table 2 should be identical.
Progress–Florida		☑	The separation of steady state and dynamic response analysis requirements into two tables (with different contingencies) is unnecessary, and is inferior to the analysis requirements outlined in Table 1 of the existing TPL Standard. The structure of the existing Table 1 reinforces the requirement for grid stability and maintaining the grid within applicable limits for Category B and C contingencies. Dynamic simulations of Category B and C contingencies that demonstrate grid stability should be followed up with post transient power flow analysis to assess voltage and thermal limits.
Tenaska		☑	The same set of contingency tests need to be applied to in both steady state and stability studies. The performance levels may need to be characterized a little differently, but at the end of the day we

Q31			
Commenter	**Yes**	**No**	**Comment**
			are trying maintain a reliable system for the same initiating event both in a stability timeframe and a steady state timeframe.
Response: The SDT believes that some contingencies are only appropriate for steady state analysis and not for stability. The SDT believes that two tables are clearer than having only one.			
BPA	☑	☑	Support comments sent by WECC. There is a link between transient stability and steady state performance for a given event since they model serial time frames for the event.
WECC TSGT TEP	☑	☑	We agree with the question asked. In addition, because of the time sequence from the start of the fault, through fault clearing and transient dynamic period, the post-transient period to the steady state post-contingency period, there needs to be clear links between the performance requirements in the transient dynamic time period and the steady state time period. For example, if generator dropping or controlled load interruption is allowed in the transient dynamic period, it should also be allowed in the steady state time period that follows. Otherwise, it would put the Transmission Planners and the Planning Authorities in an untenable situation because, once a generator or load is dropped in the first few cycles after the disturbance; it cannot be required to be on line in the minutes that immediately follow.
Response: The SDT agrees that there should be a clear link between performance requirements in the transient period and the steady state period. We believe the standard as written provides this.			
ERCOT ISO	☑		Agree that the two analyses should be treated separately. It is not clearly defined what is steady state and what is stability. For example, are Voltage Stability (PV analysis) studies steady state or stability? Also what are the differences between System Stability and Plant Stability? Are stability studies only required for the near term planning horizon?
Response: Generally, most parties did not express confusion over the issues that are raised by this question. The SDT believes the general industry understanding is as follows: • Voltage Stability (PV analysis) is considered to be a steady state study. • Generating Unit Stability focuses on an individual generating unit or electrically closely-coupled generating units at maximum power and is concerned with Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of Interconnection or one bus away from that point. System Stability studies focus on portions of the System, which may include many generating units possibly at maximum power with Contingencies in that area of the System. System studies would also include Contingencies in large Load areas (using Load models with induction motors properly represented) which could result in fast voltage collapse. • System Stability studies are only required in the Near-Term Planning Horizon. Generating Unit Stability studies could be required for the Long-Term Planning Horizon if the commercial operation date of the plant is in the long term.			
ITC	☑		We agree but consideration should be given to the amount of work needed by entities to meet these requirements. Full scale annual stability studies may not be needed. If possible, criteria should be developed as to when stability studies need to be repeated (if at all) and to what level (i.e. every bus on the system or just the generator busses or somewhere in between).
Response: Full scale annual Stability studies are not necessarily required by the standard. Allowance is made for the use of past studies in the current year assessment.			

Q31			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		Yes, I like this. You can maintain them to be as similar as possible, while still containing the requisite differences.
AECC	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		
ATC	☑		
Brazos Electric	☑		
City Water Power and Light	☑		
CAISO	☑		Agree that the two analysis should be treated separately.
CenterPoint	☑		Separating the stability requirements into a second table improved the clarity.
Central Maine Power	☑		
CPS Energy	☑		
Duke Energy	☑		
Entergy	☑		This approach clarifies the types of stability studies/simulations to be performed. The performance criteria/guidelines are more explicit under the proposed Standard.
Exelon	☑		
Dominion	☑		
E ON US	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		

Q31			
Commenter	**Yes**	**No**	**Comment**
MRO	☑		The MRO commends the SDT in separating the two tables. The single table for both types of studies has generated confusion in the industry.
Muscatine P&W	☑		
National Grid	☑		
NERC TIS	☑		Although there are many similarities, separation of the testing requirements makes the standard far more understandable.
New York ISO	☑		
NCEMC	☑		
NU	☑		
Nstar	☑		
PJM	☑		
Progress–Carolinas	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
United Illuminating	☑		
WPS	☑		
Northwestern Energy	☑		
Response: Thank you.			

32) Q32. The SDT has added requirements for plant stability studies and has drawn a distinction in these studies from System stability studies. Do you agree with this approach? If not, please explain.

Summary Response: The respondents were divided on this question. Most of the negative opinions expressed a view that there is no material distinction between plant and System Stability, with some indicating that the analysis and requirements are the same for both types of studies. Others also suggested that plant Stability is simply a subset of System Stability. In response to these comments, the SDT modified the standard to clarify the distinction between Generating Unit and System Stability.

The following items were changed due to industry comments:

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

Q32			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	I don't see any reason to differentiate between "Plant Stability" and "System Stability". These are not commonly separated, and this distinction is not standard in the industry. You should not be inventing a distinction that doesn't exist. A better differentiation would be between generator (or angular) stability and load (or voltage) stability. These are usually independently studied and independently occurring.
CenterPoint		☑	CenterPoint Energy does not see the distinction between system stability and plant stability studies as defined in the draft standard. Meeting the performance requirements set in R4.5 should suffice for all stability studies. The requirements in R4.6 seem overly prescriptive and could potentially result in numerous studies being required that would have very little positive effect on transmission systems throughout the country.
FirstEnergy		☑	We do not see the difference between plant stability and system stability. Both are based on anuglar stability of machines connected to the system and therefore, they should be treated the same.

Q32

Commenter	Yes	No	Comment
Progress–Carolinas		☑	Don't need to differentiate between plant and system. These are not usually separated. It would be better to separate angular stability and voltage stability. They are studied independently.
Tenaska		☑	It is not clear that there is any difference between the two studies.

Response: See summary response. To make the distinction clearer, the SDT has modified the definitions as well as R 2.5. The SDT also believes that specificity in R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.

Generating Unit Stability Study: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations.

~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~

System Stability Study: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.

R2.5. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:

Commenter	Yes	No	Comment
CAISO		☑	Plant stability studies are a subset of system stability studies in which loss of a generator is already evaluated to meet performance requirements. In specific situations, sensitivity analysis can be done as deemed appropriate by the TP to address a particular system problem.
Central Maine Power HQTE New England ISO NU NPCC RCS NSTAR United Illuminating		☑	A Plant Stability Study should be a part of a System Stability Study. How should and why would they be differentiated? The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
National Grid		☑	As defined in R2.5, a Plant Stability Study should be a part of a System Stability Study. The analysis and performance constraints are the same in both cases; it's just a matter of whether one or more generating units are involved.
Northwestern Energy		☑	Plant stability is an artificial distinction and is a subset of transient stability.
LADWP		☑	See my comment on the definition of Plant Stability. Unless the standard drafting team has something completely different from the common understanding of loss of synchronism and so on,

Q32			
Commenter	**Yes**	**No**	**Comment**
			transient stability covers both the so called Plant Stability and System Stability Studies.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit Stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
FPL FRCC		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work.
Progress–Florida		☑	There should be no such distinction. All stability studies must meet the Performance Requirements for "Planning Events in Table 2 - Stability Performance". If there were different Performance Requirements then the distinction may be warranted. If the format for "Planning Events in Table 2 - Stability Performance" remains in its existing state, however, system stability studies are sufficient and performing studies under the guise of Plant Stability would constitute additional work with no incremental benefit.
Response: See summary response concerning the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now Requirements R 5.5 and R 5.6). To make the distinction clearer, the SDT has modified the definitions as well as Requirements R 2.5. The SDT also believes that specificity in Requirements R 2.5 will reduce the burden of performing the stability studies necessary to ensure a reliable BES. In addition, the required Contingencies for Generating Unit Stability studies are different than the Contingencies for System Stability studies. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
Dominion		☑	More clarification is needed to distinguish the difference in studies performed for plant stability vs. system stability. For example, is a system study mainly a study of inter-area (i.e. - small signal) oscillations?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5. **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
BCTC		☑	Plant stability is a Generator Interconnection study, addressed by FAC-001. By including this requirement in TPL, costs may be transferred. TPL-001 need not distinguish between system stability and plant stability. For Planning Assessments, these are the same thing. Plant stability arises when doing generator interconnection.
Response: The SDT has considered your comments and believes that FAC-001, as currently written does not ensure that Generating Unit Stability studies are performed or that specific performance requirements are met. The SDT also believes that the distinction between Generating Unit and System Stability as described in Requirements R 2.4 and R 2.5 as well as Requirements R 4.5 and R 4.6 (now R 5.5 and R 5.6) is warranted. The SDT believes that specificity in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES.			
Manitoba Hydro		☑	The need to assess Plant Stability should be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. Furthermore, the System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. The requirement for plant stability studies appears to be redundant and would be a waste of assessment resources.
Response: The SDT has considered your comments and believes that neither FAC-001, as currently written, nor the pro forma tariff, ensures that Generating Unit Stability studies are performed or that specific performance requirements are met. Furthermore, not all entities within North America are subject to FERC's OATT.			
MRO		☑	The MRO sees the need for plant stability study requirements somewhere in NERC standards although adding this requirement into this study requires a rehash of the plant stability studies that are conducted throughout ten years or more in an annual assessment. This seems to be an unnecessary duplication. The MRO recommends that this requirement be deleted from this standard and that the

Q32			
Commenter	**Yes**	**No**	**Comment**
			SDT recommend to the NERC SAC that this requirement be covered by the appropriate future SAR.
Response: The SDT believes that the draft requirements do not lead to duplicative studies. If the studies that you reference meet the requirements of TPL-001-1, those studies would in fact satisfy the requirements and additional studies would not be necessary. Furthermore, we believe Requirement R2.5 will reduce the number of studies required because it only requires restudy for generator additions or material changes to the System near the generator.			
WECC BPA TSGT TEP		☑	It appears that Plant Stability Study is a subset of System Stability Study. R4.6.2 states these shall be performed for changes in real power output of a generating unit by more than 10%. Then it states they shall be performed for planning events. R4.5 already covers any contingencies that are an issue and the system already needs to meet some level of performance for loss of the generator. It seems that a change in generation would already be analyzed from a system standpoint as stated in R2.4.3. It appears that material changes to existing generators should be reflected in modeling requirements elsewhere.
Response: The SDT agrees that Generating Unit Stability studies can be viewed as a subset of System Stability studies. The requirements specific to Generating Unit Stability (Requirements R 2.5 and R 4.6 (now R 5.6)) reflect that view. The SDT believes that the specific focus on Generating Unit stability in Requirement R 2.5 will reduce the burden of performing the Stability studies necessary to ensure a reliable BES. To be clear, the 10 % change in generation capability (captured in Requirement R 5.6.2) is what drives the need for a revised study.			
CPS Energy		☑	
Response: Thank you.			
IESO	☑	☑	We agree that both plant stability and system stability have to be studied and that both must exhibit acceptable performance to deem a testing acceptable. The performance requirements for the two could be different, but not the contingency set that must be tested.
Response: The SDT believes that extreme event Contingencies are not required for Generating Unit stability studies.			
Ameren	☑		We appreciate the SDT concern for performing repeated plant stability studies without any change in plant/machine characteristics. However, as the system load representation and its damping characteristics affect both plant and system stability, it is difficult to separate plant versus system stability studies. On some systems in which load and generation are tightly coupled, the focus of plant or system stability studies may differ only slightly with the location and duration of applied fault events. As such, the scope and manner of conducting System Stability study work under Requirement R2.4. for such portions of the interconnected system is not clear. Differences between Plant Stability Studies and System Stability Studies need to be made more clear.
Response: The SDT recognizes that the specific studies required to satisfy the Generating Unit and System Stability requirements will be System specific. In that regard, for some Systems there may be little or no distinction and a single set of studies could satisfy all Stability requirements.			
City Water Power and Light	☑		Yes but the distinction is not clear in the definitions. A Plant Stability Study would typically be done as part of the Generator Interconnection Request and have all units in the area at maximum output. Is the System Stability Study done on the Base Case or is generation maximized within some area(s)?

Q32			
Commenter	**Yes**	**No**	**Comment**
Response: To make the distinction clearer, the SDT has modified the definitions as well as Requirement R 2.5 Also, as indicated in Requirement R 2.4, the System Stability studies should be run using base cases (peak and off-peak) as well as various sensitivity cases (Requirement R2.4.3). **Generating Unit Stability Study**: Study that focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. This study is concerned with the loss of synchronism and the lack of damping of the generating units' power oscillations. ~~**Plant Stability Study**: Study of an individual plant's Stability for various Contingencies in the vicinity of the plant; concerned with the effect on the System of the generating units' loss of synchronism and the damping of the generating units' power oscillations.~~ **System Stability Study**: ~~Study of the System or portions of the System to ensure that angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.~~ Study that focuses on portions of the System, which may include many generating units, to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits. **R2.5**. The ~~plant~~ Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect Stability margins occur:			
New York ISO	☑		NYISO agrees with the concept of splitting plant and system stability studies, but only in the area of performance requirements. The studied contingencies should be identical.
Response: The SDT believes that the selection of study Contingencies is System specific. Although it is not required, for some Systems it may be appropriate to use the same Contingency set for Generating Unit and System Stability studies.			
AECI	☑		
Allegheny Power	☑		
AEP	☑		
APPA	☑		This has been needed for some time.
ATC	☑		
Brazos Electric	☑		
E ON US	☑		
ERCOT ISO	☑		Agree with this additional analysis.
Duke Energy	☑		
Entergy	☑		See response to Q9

Q32			
Commenter	**Yes**	**No**	**Comment**
Exelon	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
ITC	☑		See response to Q31.
KCPL	☑		
LCRA	☑		
MEAG Power	☑		
MISO	☑		
Muscatine P&W	☑		
NERC TIS	☑		Planning Coordinators should study plant stability at the time of interconnection, and it should be reviewed for significant system or plant modifications that may impact the plant's stability.
NCEMC	☑		
PJM	☑		
ReliabilityFirst	☑		
Santee Cooper	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		
Southern Transm.	☑		
TVA	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

33) Q33. The existing TPL-004-0 standard has a requirement to consider the Loss of all generating units at a plant, but it was not clear whether this requirement should apply to stability studies. The SDT did not include this requirement in the stability table, because it is hard to envision a condition when all units would trip simultaneously within the timeframe of a stability simulation. Do you think this condition should be required in stability analysis of Extreme Events? If not, please explain.

Summary Response: The majority of commenter's agree with excluding the loss of all generating units at a plant in the Stability analysis of Extreme Events. The SDT agrees with not including this condition in Table 2. Nevertheless any TP or PC could study this Contingency if they believe such a study is warranted.

Q33			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	No. Good idea. A whole plant may be out because of a shortage of cooling water, but this is an orderly shutdown, not a sudden event. It is only appropriate for steady-state.
Brazos Electric		☑	
Dominion		☑	It is unlikely that all units at a plant would trip simultaneously within a short time frame (20 second or so) for which stability simulations are performed.
E ON US		☑	I agree with the SDT's conclusion.
AECI		☑	Agree with the statement above as to the time frame regarding stability.
CenterPoint		☑	CenterPoint Energy agrees with the SDT's assessment.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating		☑	Difficult to envision how such an event would occur.
CPS Energy		☑	
Duke Energy		☑	We agree with the basis laid out (in the question) by the SDT.
FirstEnergy		☑	We do not believe that this condition should be required to be tested using stability analysis of Extreme Events. This is due to the fact that these events should be required to be studied using steady state analysis, and stability analysis results would not add value.
Georgia Transm.		☑	
ITC		☑	If it is not probable, then why study it. Realistic probabilities need to be established and defined for study.

Q33			
Commenter	**Yes**	**No**	**Comment**
KCPL		☑	Agree it is difficult to develop scenario where all units trip simultaneously in stability timeframe.
Muscatine P&W		☑	Unless there is a reasonable reason to expect all the units to trip.
Progress–Carolinas		☑	
Progress–Florida		☑	Analysis of this condition should not be required in stability analysis of Extreme Events due to the fact that no stability simulation (e.g., SLG or 3-phase faults) can be conceived for the Bulk Electric System that would result in simultaneous tripping of all units at a plant.
SERC EC DRS		☑	This question conflicts with Table 2 Extreme Event 9. However, we feel it is not necessary to simulate loss of all units at a station because simultaneous loss of all units is unlikely.
SERC RRS OPS		☑	It is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc.
Southern Transm.		☑	
Response: Thank you.			
BCTC		☑	Stability should be treated the same as steady state. If there is a common mode event that could cause the loss of all generating units at a plant, all relevant simulations should be done. If a common mode contingency of all units at a generating plant is not relevant for stability, then it is not relevant as an extreme event for steady state either. However, operation with all units at a plant off line may be relevant as a sensitivity case for Planning Events. The Transmission Planner needs some lattitude to determine what needs to be considered under Extreme Events and the standards should not be overly prescriptive.
Response: The SDT disagrees with this point of view. There are Extreme Events which are relevant for steady state but not for Stability analyses.			
Entergy		☑	This question conflicts with Table 2 item 9. However, we feel it is not necessary to simulate loss of all units at a station. The Transmission Planner or Planning Authority should have the discretion to consider the appropriate number of units to be tripped based on station design, relay design, etc. Since there is no specific question related to R3.4 that requires an evaluation be conducted of implementing a change designed to reduce or mitigate the likelihood of such consequences. More specific direction should be provided in this regard.
LADWP		☑	Loss of a plant as an extreme contingency has been on the book forever and it has never been interpreted as exempted from stability simulation (at least not in WECC) if this scenario is chosen as an extreme event. However, there is no mandatory requirement that loss of all generating units at a plant must be studies for every generating plant. If the design of a generating plant, such as use of redundancy, separate control console/rooms, etc., are such that all unit tripping simultaneously is unlikely, then it should not be required to be studied just because all the units are inside the fence.
Response: The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis,			

Q33			
Commenter	**Yes**	**No**	**Comment**
from the Extreme Events of Table 2 does not preclude the Planner from performing this study. The language in R3.4. allows the TP or PC to evaluate the risks versus the costs of implementing mitigation or a reduction of the possibility of that Contingency.			
FPL FRCC		☑	The question does not match what is included the Extreme Events section of Table 2. Loss of all generating units at a plant should be considered in the Steady State Performance - Extreme Events but not in the Stability Performance - Extreme Events because of the very low probability of the event occurring within the timeframe of the Stability simulation. Therefore, the performance requirement number 9 for Extreme Events in Table 2 - Stability Performance should be deleted.
Response: The SDT agrees and has removed the Contingency from Table 2.			
MEAG Power NCEMC SERC EC PSS SCE&G		☑	Generator protection is designed to trip only those units required. In addition, it is the magnitude of generation tripped rather than the number of units tripped that is of the greatest significance to the stability of the grid.
Response: The SDT agrees that the magnitude of the generation being tripped is significant and should be studied when applicable. The SDT agrees that the removal of the Requirement to consider the loss of all generating units at a plant in Stability analysis from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
New York ISO		☑	Examples of loss of entire generation station: Complete loss of right-of-way exiting facility, simultaneous relay operations due to common cause or mode.
Response: Your examples may be applicable to a site in your area and if you desire, you can continue to study steady state and Stability but the removal of this note from the Table does not stop the TP or PC from performing the stability studies if desired.			
Santee Cooper		☑	The transmission planner should have discretion to consider the appropriate number of units to be tripped based on the station design, and/or relay design.
Response: The SDT agrees that the removal of the Requirement, to consider the loss of all generating units at a plant in Stability analysis, from the Extreme Events of Table 2 does not preclude the Transmission Planner or Planning Coordinator from performing this study.			
SaskPower		☑	What is the purpose of requiring this event or any other extreme event to be studied? We see little benefit in this. In the Saskatchewan context we accept the risk and consequences for Extreme Events as there is usually very little justification for the increase in reliability versus the economic cost. Saskatchewan plans and designs its system to fail safe in those events and restores the system thereafter.
Response: The SDT agrees with your comment and that is the reason Question 33 was asked of the industry.			
Tenaska		☑	Only on a case by case basis where a common mode/single point of failure can be identified that results in the loss of an entire plant.
Response: The SDT agrees with your statement.			
TVA		☑	This question conflicts with Table 2 Extreme Event #9.
Response: The SDT agrees that this is in conflict with Table #2 Extreme Event #9 and that is why the SDT has now removed it from the Table.			
WECC		☑	We agree with the SDT that simultaneous 3-phase fault on all generating units in a plant is

Q33			
Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			improbable and effort should be better spent studying more probable events. In any case, this Extreme Event is to be considered in the Steady State Table, and stability cases can be run if it is shown to be needed in the power flow study results. We are, however, confused by this question. This question states that the SDT did not include the requirement to consider loss of all generators at a plant in the stability, yet the Extreme Event in the stability table shows in No. 9, "3Ø fault with loss of all generating units at a station".
Response: The SDT agrees with your comment and apologizes for the confusion from the wording of the Question. The Contingency has been removed from the Table.			
Northwestern Energy	☑	☑	If such a standard is constructed, it should be based on a common mode of failure mechanism.
Response: The SDT agrees in removing this from the Table #2. However, the Standard language does not preclude a Transmission Planner or Planning Coordinator from studying this, if applicable. The Standard will allow the TP or PC to perform the study without it being a Requirement.			
AEP	☑		Extreme Event #9 in Table 2 has 3-phase fault and loss of all generating units at a station. Was this left in by mistake? This type of scenario could conceivably lead to low interconnection frequency or cascading due to consequent transmission overloading or low voltage, and could be studied by dynamic simulation. There have been a number of just such generation loss events as this in the past.
Response: The SDT did not leave the 3-phase fault in by mistake; it was intentional and follows with the other Requirements in the Table. Rather, Question 33 was phrased incorrectly in stating that this requirement had been removed from the Table. However, by not having this listed in the Requirements does not preclude the Transmission Planner or Planning Coordinator from studying this condition if applicable to their system.			
APPA	☑		This is a conditional Yes. If the plant design was such that a fault at the plant could remove all units, then all units should be considered. However, if the plant design is such that the likelihood of all plants going down at one time is improbable, then the SDT's approach is very reliable.
Response: The proposed removal of note #9 in the Table will not preclude Transmission Planners or Planning Coordinators from studying this condition if applicable.			
IESO	☑		Consistent with our comments provided under Q31, while the performance requirements may be different, there should be no distinction made to the type of contingencies that need to be applied to steady state testing and stability testing. An entire generating station may be lost due to various possible reasons: lost of right of way of transmission lines emanating from the generating station; generic protective relaying problems which cause all relays to operate due to a common cause or common mode event.
Manitoba Hydro	☑		Isn't 2.d such an event? In a breaker-and-1/3 or 1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause a major disruption with individual generators connected to other stations by separated lines. That is certainly worthy of consideration as a feasible "extreme" event Further, the same low likeihood argument could be applied for the majority of Extreme Events in Table 2.The emphasis should be on what the response is for Extreme Events rather than the likelihood of the event.

Q33			
Commenter	**Yes**	**No**	**Comment**
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which remove all of a generating unit from the System occur over a longer period of time which is more applicable in the steady state analyses. These are Extreme Events which are relevant for steady state but not for Stability analyses.			
MRO	☑		In a breaker-and-1/3 or breaker-and-1/2 generating station, if one station bus is off-line for maintenance, faulting the other bus will kill the station, or at least cause major disruption with individual generators connected to other stations by separated lines or AC separated DC converter transformers via isolated station bays. That is certainly worthy of consideration as a feasible "extreme" event.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis for Extreme Events. The events which occur to remove all of a plant from the system occur over a longer preiod of time which is more applicable in the steady state analyses.			
NERC TIS	☑		Simultaneous loss of the entire generating stations have occurred on 4 occasions in the last 3 years, with simultaneous losses ranging from 1,100 MW to over 3,700 MW. It is important to understand the stability implications to the system and other plants.
Response: The SDT and the majority of the Industry do not think that this should be required in Stability analysis for Extreme Events. The SDT does not believe these events would result in the loss of all generation in a Stability timeframe.			
PJM	☑		Yes, but should model the true clearing times of each individual unit. Also the standard should clearly state that system reinforcement should not be required for this Extreme Events.
Response: The SDT and the majority of the industry do not think that this should be required in Stability analysis. However, by not having it listed in the Requirements does not preclude a Transmission Planner or Planning Coordinator from studying this particular condition. Also, refer to the language of current standard Requirement R5.5.4 which addresses the reinforcement logic.			
Allegheny Power	☑		
Ameren	☑		A good test of the robustness of the interconnected system is its ability to handle import plus heavy inrush conditions, such as might occur with loss of a large plant. While the probability of such random events would be very low, the possibility still exists that intentional sabotage could result in such an event.
ATC	☑		
Response: The loss of a large gas pipeline into a region is not the same as a 3 phase fault at the generator bus location. If the gas line were ruptured, the units would be shut down over a period of minutes, not in a stability time frame. The E3.a in Table 1 is for steady state analysis.			
City Water Power and Light	☑		If there is any single contingency event that could take out an entire plant, it should be studied.
ERCOT ISO CAISO	☑		It will be consistent with the performance requirements under Steady State conditions. Also, loss of entire generating station is possible for a variety of reasons such as, loss of all lines emanating from the station, loss of the gas pipeline feeding the plant, etc.
Response: The loss of a large pipeline would not result in the sudden shutdown of all units within a stability timeframe. The shutdown occurs over tens of minutes.			

Q33			
Commenter	**Yes**	**No**	**Comment**
AECC	☑		It should also be considered in steady state analysis.
Exelon	☑		
ISO/RTO	☑		
LCRA	☑		
MISO	☑		
Seattle City	☑		
WPS	☑		
Response: Thank you.			

34) Q34. There are an increasing number of events with slow voltage recovery after faults on the Transmission System. The dynamic behavior of induction motor loads is a major factor in this phenomenon. The proposed standard therefore requires that the load model for stability studies of peak Load conditions include the dynamic effects of induction motors. Do you agree with this requirement? If not, please explain?

Summary Response: There is consensus that slow voltage recovery is an observed phenomenon that requires study and potential corrective action. However, nearly all responders noted the difficulty of obtaining accurate dynamic Load models. Based on the responses, the study of this phenomenon is in its relative infancy. Most responders are looking for guidelines for these studies whether they answered 'yes' or 'no'. The Transmission Issues Subcommittee (TIS) is forming a working group (TIS WG) to write a technical white paper on this issue. The SDT has recommended that this group include guidelines for load models in their white paper.

Based on industry comments, the SDT believes that this is such an important issue that a Requirement should be in place. As such Requirement R2.4.1 was changed. It will be up to those performing the studies to document their dynamic Load models.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~ a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

Q34			
Commenter	**Yes**	**No**	**Comment**
E ON US		☑	I agree that this is an issue but I do not have sufficient data to accurately simulate the condition. This is also complicated by dynamic behavior of distribution capacitors which are not modeled.
SERC RRS OPS		☑	There is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. Transmission planners should be able to use the latest information and techniques.
SCE&G		☑	There should be an attempt to represent the dynamic behavior of induction motor loads in the generic system load representations. However, the state of induction motor load modeling is not adequate to permit discrete induction motor load models.
AEP		☑	The statements of fact in the question may be true for some study areas, but not necessarily for all. Requiring this type of load representation when it might not be appropriate to the study is excessively burdensome. This is a judgment better left to those conducting the studies. The percentage of load to be so represented, the extent of the study area over which to apply induction machine representations, and the specific modeling parameters are all judgments just as important as whether or not to include this type of representation. There is a limit as to how far a standard can replace engineering judgment and that limit is reached here.
CenterPoint		☑	CenterPoint Energy includes the dynamic effects of induction motor loads in stability studies. However, this requirement is overly prescriptive since some utilities may not need to include the dynamic effects of induction motors and should not be required to do so.
Central Maine Power National Grid New England ISO		☑	This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are

Q34			
Commenter	**Yes**	**No**	**Comment**
NU NPCC RCS NSTAR United Illuminating			required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
Duke Energy		☑	In general, it is a good practice for System Stability studies of seasonal load conditions to include the effects of induction motors. However, there is currently a lack of data to support the amount and characteristics of detailed induction load models in many areas. Prior to making this a requirement, the industry needs guidance as to how this data should be developed, shared and maintained for near-term and long-term models. A long term transition period is required to incorporate motor models into dynamics studies.
Entergy		☑	In general this is a good practice. Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. This should be a business practice and thus removed from the standard. While we agree that each entity should appropriately model their loads, it would seem appropriate for the MMWG to address the issues of induction motor load modeling. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years.
FPL FRCC		☑	The issue of delayed voltage recovery is a special phenomenon that can occur in some large urban areas under peak conditions. The modeling of the delayed voltage recovery response is considerably more complex than simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. While improvements in the accuracy of load models used for the study of grid dynamic response are desirable, this area is not suitable for compliance enforcement. Requirements for specific types of load models are not appropriate in the TPL standard.
KCPL		☑	Transmission operators are required to maintain reactive reserve requirements.
MEAG Power NCEMC SERC EC DRS SERC EC PSS TVA		☑	Dynamic studies of seasonal load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at distribution voltage levels would need to be considered as

Q34			
Commenter	**Yes**	**No**	**Comment**
			well. Prior to making this a requirement in the reliability standards, the industry needs guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Maintenance of such load model data would require significant resources. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Muscatine P&W			We have not seen this on our system based on the review of digital fault recorders (DFR). The difficulty with including induction motors is getting reasonable data from customers about their motors so they can be adequately modeled. (We did ask our consultant to include motor effect in our coordination study since the motors could act as a weak source.)
PJM		☑	No. This is good in theory but is impractical to implement with the large interconnected systems that span large geographical areas.
Progress–Florida		☑	Requiring detailed modeling of every induction motor on the Bulk Electric System for stability analysis is onerous. Specifically, obtaining a complete set of data for existing induction motors would be infeasible, as would tracking future installations of induction motors. The benefits of such an effort are significantly outweighed by the logistical difficulties. To address the technical merits, the modeling of the delayed voltage recovery response that has been observed in some large urban areas during periods of high air conditioning usage is considerably more complex than can be addressed by simply representing induction motor effects. The scope of the delayed voltage recovery issue is extremely limited and its effect on the grid is generally self correcting due to automatic disconnection of the affected air conditioners. Requirements for specific types of load models are not appropriate in the TPL standard.
Santee Cooper		☑	The characteristics of detailed induction load are generally lacking to properly model induction loads. Load modeling should be left to the judgment of the TP.
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			
CPS Energy		☑	
Response: See summary response.			
AECC		☑	if someone want to study the effect of large motor load then fine but it should not be a requirement of a standard
Response: The SDT has received comments regarding the technical merits to include such behavior when appropriate. The SDT feels that proposing this requirement could potentially result in System studies that indicate System response that would meet the performance requirements when in fact the response may fall short.			
Ameren	☑	☑	Dynamic studies of peak load conditions should include the effects of induction motors, and particularly in areas where traditional load models have indicated a problem. Unfortunately, there is a lack of data to support the amount and characteristics of the detailed induction load models in

Q34			
Commenter	**Yes**	**No**	**Comment**
			many areas. In addition to the consideration of the dynamic effects of induction motor loads, the effects of static capacitor banks installed at both distribution and transmission voltage levels would need to be considered as well. The industry would be looking to NERC for some guidance as to how this data should be developed and maintained for models in future years. Note that meeting such a requirement would necessitate a significant increase in the dynamic data needed to represent the system. Also, maintenance of such load model data would need to be considered. Load characteristics valid for a near term model might not be valid for future years. Also, summer peak load, winter peak load, and off-peak load characteristics would differ.
Dominion	☑	☑	The dynamic effects of induction motor load at peak load conditions should be studied only on a limited/selected basis and should not be required for the entire system as a routine study practice. The following are examples where such an effort might be warranted: (a) where slow voltage recovery has been actually observed in the field following a fault clearance (b) where steady state analysis (P-V & Q-V curves) indicates a possible voltage collapse scenario for stressed system conditions (c) for a non-convergent (or very difficult to solve) power-flow case for stressed system conditions while solving for a contingency scenario.
Exelon	☑	☑	This is more pertinent to longer term voltage stability, so the load model should be developed and available for these types of studies.
WECC TSGT TEP BPA	☑	☑	The requirement to include motor load should be extended to other load level periods and not be limited to peak load period only. However, to capture slow voltage recover phenomena, especially in areas of high penetration of refrigerated air conditioning load (e.g. 50% to 60%), would require modeling down to the distribution system voltage level and explicitly representing shunt capacitors and various induction motor types (e.g. equivalents for single phase motors). If the requirement is not extended, dynamic simulations will likely differ significantly from observed system events. We recommend a phase-in period so that the requirement for use of load models should only include regionally accepted load models for which data are available. This requirement can be extended or modified as the Region in which the entities reside adopts new load modeling guidelines.
Brazos Electric	☑		However, acquiring load data may be difficult if not impossible and would require increased manpower. A more reasonable approach is to vary the load data to see the effects instead of wasting effort on load surveys.
City Water Power and Light	☑		However, low voltage often causes motors and air conditioner compressors to trip, significantly reducing peak loads.
ERCOT ISO CAISO	☑		The requirement to include motor load should be extended to other load levels as appropriate.
FirstEnergy	☑		We agree with this concept but believe that enforcing it would be very difficult. There are no standards on modeling induction motor load, be it type of models, percentage of load that is motor

Q34			
Commenter	**Yes**	**No**	**Comment**
			load, or percentage of large vs small motors.
HQTE	☑		This requirement is too specific and limited. Induction motors are only one component of a complex load model. Complex load models are not always necessary, nor are they always the most conservative, depending on the analysis that is being conducted. Where complex load models are required, they should be considered; this may involve use of complex motor and lighting loads or polynomial load representations with or without frequency dependence. This question also suggests the need for an industry standard regarding transient voltage recovery.
IESO	☑		Dynamic testing should assess response of moving equipment including induction motor loads.
ITC	☑		However this will require the Load Serving Entities provide specific data for each bus on the system which may not be in the direct control of the entity performing the studies. The standard should be written with this understanding in mind. Failure of a LSE to provide such data should not cause a penalty to be imposed on a Transmission Provider.
LADWP	☑		This is a qualified yes to the extent that accurate induction motor models are available and the overall load modeling (non-induction motor loads) allow such analysis. Otherwise, focusing only on induction motors would not provide added information than what is being performed today. The current WECC requirement concerning induction motor modeling should be deemed adequate to meet this requirement.
Manitoba Hydro	☑		R2.4.1 should be clarified to limit a requirement for detailed modeling (for example, dynamic effects of induction motors loads) to local areas where the planner expects a local emerging voltage recovery issue.
MISO	☑		Yes, we agree that appropriate induction motor loads should be modeled. No, it is not be practical to model all induction motor loads. There needs to be size and location considerations. Data is not readily available today.
MRO	☑		The MRO agrees that R2.4.1 should provide for the inclusion of dynamic behavior of induction motor loads, however, recommends that there should be a limitation on only requiring such behavior where significant such as large motor loads over a certain MW amount. As written, it could be interpreted that the Transmission Planner is non-compliant if all induction motors are not represented.
Progress–Carolinas	☑		This needs to be done but we currently don't have sufficient data and tools to properly perform the analysis. More interconnection-wide testing and data collection needs to be performed. We will need to transition into these studies over time.
ABB	☑		Yes, but the impact on the models and studies is unknown. Some testing needs to be done with full Eastern and Western Interconnection models to see how they handle motor models at every load. I've performed numerous studies where loads in an entire utility or state have been converted to a large % of motors, and the effect can be shocking. The programs (PSS/E and PSLF) may completely bog down if this is done for a whole interconnection. Many stability problems will be found. We definitely need to transition to this, but with care.
Northwestern Energy	☑		

Q34			
Commenter	**Yes**	**No**	**Comment**
AECI	☑		However, getting all the modeling data is not easy and may take some time.
Allegheny Power	☑		
APPA	☑		The SDT is correct to include the effects of induction motors in simulating the loads. Voltage issues are and will continue to become more critical in the operation of the BES as time goes by. It will be a big help to planners and operators to know the impacts of such loads.
ATC	☑		
BCTC	☑		
Georgia Transm.	☑		
ISO/RTO	☑		
LCRA	☑		
NERC TIS	☑		If such known phenomena are not properly modeled, how can the resultant study results be expected to be correct and a proper prediction of future system behavior. The modeling shortcomings of the Western Interconnection prior to the August 1996 western blackout showed no potential stability problems for the events that occurred; the system proved otherwise.
New York ISO	☑		
SaskPower	☑		
Seattle City	☑		
Southern Transm.	☑		
WPS	☑		
Response: See the summary response, The SDT has recommended that the TIS WG writing the white paper on this phenomenon review your suggestions and comments.			

35) Q35. What type of manual or automatic adjustments of generators should be allowed for single and multiple Contingencies?

Summary Response: Most responders said or implied that all adjustments should be allowed for both single and multiple Contingencies. Some respondents further clarify their response by adding the adjustments must be achieved within a specific timeframe such as meeting performance requirements or the ability to keep the generator on-line. A small number of responders replied that no adjustments should be allowed for single Contingencies but then agreed that adjustments may be allowed for multiple Contingencies.

The SDT has modified Requirement R 3.6 (now R3.5) of the steady state portion of the Planning Assessment to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q35	
Commenter	**Comment**
ABB	For multiple, only automatic schemes. For single, only automatic schemes if the loss of MW is shown to be acceptable.
Ameren	No adjustment of firm (network resource) generation should be allowed for the long-term mitigation of a single contingency. Allowing post-contingency shifts of firm generation as a long-term mitigation of a single contingency event is short-sighted and would not produce a robust system that is required to handle more than single contingency events. Redispatch of firm generation may be required in the near-term as an interim operating guide or procedure until the limiting transmission element can be uprated or other system reinforcement is in place. Generation redispatch should also be allowed to prepare for the next single contingency. For responding to multiple contingencies, redispatch of firm generation should be allowed in the mitigation plan provided that the redispatch can be accomplished in the required operating time and the contingency overloads are not overly severe (indicating possible cascading). Firm generation should also be tripped to quickly mitigate contingencies involving multiple generation outlet transmission circuits. Non-firm (energy only) generation can be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
City Water Power and Light	Dispatching quick start units such as combustion turbines or diesels, Contingency Reserve Sharing Group response, redispatch, adjust reactive resources as necessary.
Dominion	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
E ON US	single – none
ERCOT ISO CAISO	Manual such as tripping the generators, automatic such as AVR, excitation systems, stabilizer, and governor adjustments. From a Planning perspective, you would not want to allow for manual tripping in the time frame of a stability study.

Q35	
Commenter	**Comment**
BCTC	No restrictions on adjustments that are practical and can be achieved within the timeframe required.
Northwestern Energy	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. Also, if a RAS (or special protection system) is the adjustment and if cascading could result from the event, then redundancy should be required.
MEAG Power NCEMC SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
AECI	Whatever the generator is capable of.
Allegheny Power	Should not be limited.
AEP	The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c. Generation is a system resource and should be protected against the more common single contingency transmission events. We agree with the status quo on this issue being maintained in the new standard, with the provision for regional variance in R3.6. The provision for manual and automatic runback in R3.5 is okay. We also agree with manual adjustments remaining acceptable in response to any contingencies in the new standard consistent with C3 in existing TPL-003.
Central Maine Power HQTE National Grid New England ISO NU NPCC PCS NSTAR United Illuminating	Manual or automatic adjustments should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment. Manual system adjustment should be allowed in between the multiple Contingencies described in P5, provided that the adjustment can be made between contingencies using short-term reserves (10-30 minute).
Duke Energy	This question is not clear. Manual and automatic adjustments should be allowed for single and multiple contingencies as long as Performance Requirements are met.
Exelon	Generator MW and Mvar output adjustments should be allowed, both manual and automatic.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
FPL FRCC	Manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall MW output of generators should be allowed.
Georgia Transm.	Special Protection Schemes should be allowed for single and multiple contingencies.
IESO	Automatic adjustments should include AVR, excitation system, stabilizer and governor, all of which have pre-determined settings. These adjustments should be allowed for any type of contingencies. Manual adjustments that should or can be made other than removal of the generating units from service could include manual switching of

Q35	
Commenter	**Comment**
	transmission and adjustment to Phase Angle Regulators for so long that these actions are documented as applicable operating procedures.
ITC	There should be no change in generation for single contingencies. An approved SPS in those areas that use them might be an exception however system damage for failure to operate should not be allowed beyond the station with the SPS. Also, loss of load should not be allowed for failure to operate. An automated adjustment for multiple contingencies is not unrealistic.
KCPL	Generation redispatch should not be allowed for N-1 events. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
LADWP	Whatever is needed to bring the system into balance.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Adjustment of firm transfer must be allowed for single and multiple contingency events. MH could not accept the revised standard that removed this existing requirement.
MISO	Generation redispatch should not be performed for single contingencies. Generation redispatch is appropriate for multiple contingencies. Appropriate SPS and generation runback schemes should be allowed, where the system is designed with those schemes.
MRO	Here are the adjustments that the MRO believes the MRO systems are presently designed to meet and what an MRO Augmentation Drafting Team is proposing to require its members to follow for Category B and C events: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Generation rejection to the extent possible within the allowed readjustment period. Generation rejection shall not exceed the normal operating reserve of the generation reserve sharing pool to which the MRO Member belongs or of the MRO Member itself if the MRO Member self-provides generation reserves.
Muscatine P&W	Whatever the local entity sees as appropriate and is reasonable versus the cost of fixing the problem. (See Q43 Comment #3)
NERC TIS	If system adjustments are allowed between events in steady state analysis, manual and automatic adjustments should both be allowed. However, in stability analysis, only automatic adjustments capabilities that are actually in place should be used.
New York ISO	Automatic: Pre-determined ranges of AVR, excitation system, stabilizer and governor. Manual: switching and PAR adjustments covered by applicable operating procedures.
PJM	Adjustments should be allowed consistent the time periods being studied.
Progress–Carolinas	Both manual and automatic adjustments should be allowed.

Q35	
Commenter	**Comment**
Progress–Florida	Provided events are confined to a single area (i.e., no cascading outages), manual and automatic adjustment (increase or decrease) of Var output and manual and automatic tripping or reduction of overall output of generators should be allowed
Santee Cooper SERC RRS OPS TVA	Any adjustments should be allowed that protects the reliability of the BES.
SaskPower	The amount of generation change should be limited to the amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. Generation rejection should not exceed the normal operating reserve.
Seattle City	Any adjustment required to respond to a contingency should be allowed, unless it adversely impacts the regional system.
SERC EC DRS	Manual and automatic adjustments should be allowed for single and multiple contingencies as long as performance requirements are met.
SERC EC PSS SCE&G	Adjustments that should be allowed are those that can be performed in time to prevent the system from failing to meet performance requirements. These adjustments may include automatic voltage regulator action, governor action, generator runback, and generator tripping.
Southern Transm.	Automatic generator tripping should be allowed for single contingency events and for multiple contingency events.
Tenaska	Any adjustment(manual, automatic, runback, tripping) should be allowed as long as the performance requirements are achieved as described in standard after the adjustments have been made.
WECC BPA TSGT TEP	All adjustments should be allowed as long as they are realistic and achievable in the time frame required and consistent with other study parameters. For example, automatic adjustments would be required for correction of a stability problem, but manual adjustment should be allowed for correction of a thermal problem if there is no instability problem.
AECC	any that are realistic, can be accomplished in the appropriate timeframe and are within the capability of the units
Response: Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenci~~es~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	
APPA	I do not understand the question. Is this dealing with voltage adjustment or power adjustment?
Response: Generation runback deals with a machine's power adjustment.	
Entergy	This question is not clear and more explanation should be provided, such as, whether the adjustments are pre or post contingency, whether the contingency involves faults etc. Does this question pertain to plant or system stability?
Response: Adjustments are post-Contingency. Based on the majority of industry responses, the SDT has modified Requirement R 3.6 (now R 3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.	

Q35	
Commenter	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:	

F) Generation Runback and Tripping

The SDT has discussed the automatic and manual readjustments of generators that should be permissible for single contingencies and multiple contingencies. The existing TPL-001-0 through TPL-004-0 standards through footnote (a) of Table I could include emergency ratings applicable for short durations as required to permit operating steps necessary to maintain system control. The footnote is silent about allowable generation adjustments in response to the Category B events. However, it does indicate that system adjustments are permitted to prepare for the next Contingency. These system adjustments could include manual or automatic adjustments involving generation.

The SDT has learned that many transmission owners use System Protection Systems (SPS) or Remedial Action Schemes (RAS) to trip generation for single and multiple Contingency outage events to prevent overloads, low voltage, and instability in the Interconnected Transmission network for N-1 and N-2 events. In some cases, the RAS are used to prepare for the next Contingency; but in some cases, the RAS are used to simultaneously avoid exceeding emergency ratings.

36) Q36. The proposed standard allows generation runback after the disturbance that causes a single Contingency (or due to a single Contingency outage) to move the Interconnected Transmission System from an emergency state (within emergency ratings) to a normal state (within normal ratings), assuming that the disturbance does not result in instability? Do you agree? If not, please explain.

Summary Response: The overwhelming majority of respondents believe that generator runback should be allowed for single Contingencies. One respondent thought that runback of firm generation should only be allowed as an interim Operating Procedure until System reinforcements are installed. Another thought that a generator that must reduce output for N-1 is not "firm" generation capacity. Another cautioned that runback may not be fast enough to avoid voltage instability. The draft standard will continue to allow manual or automatic generation run-back as a response to single and multiple Contingencies as long as all Facilities shall be operating within their Facility Ratings and as long as a sustainable, stable, operating condition is maintained.

The following requirements have been added due to industry comments:

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

Q36			
Commenter	**Yes**	**No**	**Comment**
Ameren		☑	The runback of firm generation should only be allowed as a valid interim operating procedure until a system reinforcement would be installed to uprate or unload the limiting facility. The use of the runback scheme should not be allowed as the long-term solution to a single contingency event. As mentioned above in the response to Q35, non-firm (energy only) generation should be tripped or redispatched for any contingency event as needed to keep facility loadings within ratings.
Response: The SDT and the majority of the industry do not agree that generation runback should be used only as a temporary solution.			
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit

Q36			
Commenter	**Yes**	**No**	**Comment**
			trip should only be allowed if a unit becomes unstable.
Response: The SDT and the majority of the industry agree that the use of generation runback should be allowed for single Contingencies.			
AECC		☑	Generation runback should only be permitted if there are no impacts to area interchange and firm transactions are not altered.
Response: The allowable impact to firm transactions is specified in the performance tables. The use of generation runback is only allowed if the performance requirements are met.			
E ON US		☑	I do not agree that the system has to be returned to a "normal state" after a single contingency. The system can continue to be operated in the "emergency state" as long as the next contingency does not cause flows above emergency ratings.
Response: The SDT agrees that the System can be operated in an emergency state as long as the next Contingency does not cause flows above emergency ratings. However, this does not preclude the use of runback to get flows back within normal ratings.			
BCTC		☑	We do not accept R3.5, which does not limit runback to contingencies based on thermal limits, only that Facility Ratings are not exceeded. If an SOL is based on voltage stability (which is often studied in the post disturbance steady state), Facility Ratings may not be exceeded but runback may not be fast enough to avoid voltage instability. Furthermore, runback for single contingencies should be subject to any conditions that might apply to generator tripping for single contingencies. See response to Question 39.
Response: Requirement R3.5 now has two additional qualifiers on the use of generator runback other than Facilities must be within Facility Ratings: **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained.			
KCPL		☑	All generators must have "firm" transmission outlet capacity for their nameplate rating. This means delivery of full output under N-1 conditions. A generator that must reduce output for N-1 is not "firm" generation capacity.
Response: The SDT believes that if an n-1 Contingency results in flows within emergency ratings, then the generator has firm Transmission outlet capacity even if it must be backed down to get the System back within normal ratings.			
MISO	☑	☑	Yes, where the transmission system is designed with these schemes. No, in general when there is no designed SPS or runback for the generator.
Response: The SDT believes that runback should be allowed both for existing schemes and for new schemes.			
ABB	☑		Every single event will eventually require preparing for the next event. But we cannot plan for every next event. Only specific single and multiple contingencies should be planned for, all flows must be within an established rating of some kind (continuous, 12-hour, 4-hour, 15-min, whatever), and the idea of the "next event" should not be included in a planning standard. Now maybe there should be a limit as to how short the time of a rating can be in Planning. For example, planning to a 15-min rating is a bad idea. That rating can be used by operators in emergencies, but planners need to do something better. A minimum should be set (e.g. 1 hour

Q36			
Commenter	**Yes**	**No**	**Comment**
			rating). I guess if a company wants to use a 15-min rating and then AUTOMATICALLY transition to a 1-hour or 12-hour rating with runback or something else, that is reasonable.
Response: The SDT considered minimum time duration for the emergency ratings used in planning. However, the SDT decided this would be too restrictive.			
AEP	☑		Question: Why would a runback scheme be needed to move from an emergency state to a normal state when that could be accomplished by regular redispatch?
Response: If regular redispatch can adjust the System following a single Contingency in preparation for the next Contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
APPA	☑		However, it should be pointed out that RAS are band-aid solutions to building needed BES infrastructure. Experience has shown that an interconnection can have so many RAS that one RAS will counter another RAS designed for another problem in the interconnection. This problem requires additional study by a NERC task force.
Response: The SDT and the majority of the industry do not agree that automatic generation runback (by use of an RAS) should be used only as a temporary (or band-aid) solution.			
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	☑		Generation runback should be permissible to allow redispatch to return the system to below normal/load cycle based ratings; however, the system should not exceed applicable emergency ratings prior to the adjustment
Response: The SDT agrees.			
Exelon	☑		An automated run-back scheme should be allowed but not required for these scenarios - an operator should be able to manually adjust unit output.
Response: If an operator can adjust the system following a single contingency in preparation for the next contingency in the time frame required by emergency ratings, then no automatic runback is needed.			
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, either automatic or manual runback of the unit should be allowed. Tripping of the unit should be allowed also if the particular unit(s) can be restarted within some relatively short time - say one hour. With this requirement, it appears that only CTs and hydro units would be allowed to be tripped.
Response: The SDT agrees that automatic or manual runback should be allowed. We do not agree that only CTs and hydro units could be tripped by SPS.			
Manitoba Hydro	☑		Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission There will be a large cost penalty to construct transmisison to remote generation if generator tripping is not allowed. Since the amount of tripping is covered by operating eserves, there is no impact on reliability. Generator tripping should be an option for the planner in the standard as opposed to a regional difference or the need to

Q36			
Commenter	**Yes**	**No**	**Comment**
			install an SPS.
Response: The SDT agrees that generator tripping should be allowed for single and multiple Contingencies (See R 3.5)			
New York ISO	☑		What is the difference between a SPS and RAS? Would not one term be sufficient? SPSs should not be considered a permanent solution. They should only be used as a stop gap before a permanent solution can be implemented.
Response: SPS and RAS are synonymous terms. The SDT and the majority of the industry do not agree that SPS should be used only as a temporary solution.			
ERCOT ISO	☑		Agree
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
ATC	☑		
BPA	☑		
Brazos Electric	☑		
CAISO	☑		Agree
CenterPoint	☑		
City Water Power and Light	☑		
City Utilities/Springfield	☑		
CPS Energy	☑		
Duke Energy	☑		We see this as an acceptable form of manual or automatic redispatch, which should be allowed as a cost beneficial way of operating the system in a reliable manner, as long as it can be accomplished within the time frame before emergency ratings are exceeded.
Entegra	☑		As long as the system would be within normal ratings after runback.
Entergy	☑		
FPL	☑		
FRCC	☑		
Georgia Transm.	☑		
IESO	☑		Generation rejection and runback are not uncommon to be employed as special protection systems (SPS) to achieve a stable state and/or reduce transmission loading to within pre-determined levels.

Q36			
Commenter	**Yes**	**No**	**Comment**
			SPSs, when employed, are designed to operate in order to meet performance requirements following specific contingencies or when specific system conditions are present. As such, when a contingency occurs or when the conditions should arise for which the SPS (in this case, generation runback) is designed to operate, such actions should be simulated.
ISO/RTO	☑		
ITC	☑		
LADWP	☑		Generator runback is allowed under the current standards, why single this out? Hopefully this is not a sign of equating generator runback with generator tripping as the title of this section might suggested. Generator runback is not and should not be classified as an SPS! It is critical to keep as many units on line as possible post contingency. In many instances, use of generator runback would avoid the need to trip a unit if that was the only way to reduce the generations to return to load-generation balances.
MEAG Power	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event.
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
Progress–Florida	☑		
SRP	☑		
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
SCE&G	☑		

Q36			
Commenter	**Yes**	**No**	**Comment**
Southern Transm.	☑		
Tenaska	☑		
TVA	☑		
TSGT	☑		
TEP	☑		
WECC	☑		
WPS	☑		
Response: Thank you. Please see the Summary Response.			

37) Q37. Since emergency ratings are thermal ratings, should this standard allow an automatic generation runback scheme (that is initiated immediately after the disturbance causing the single Contingency) to prevent thermal overloads (assuming that the disturbance does not result in instability)? If yes, what are the conditions that must be met in order to allow such a runback scheme to meet the System performance criteria for single Contingencies? Please explain the reason for your answer.

Summary Response: Respondents appeared to overwhelmingly favor allowance of automatic generation runback to prevent thermal overloads. However, as some respondents indicated the question was not clear and a number indicated that Requirement R 3.5 could be made clearer. Many respondents suggested various conditions be added to the requirements. The SDT has modified Requirement R 3.5 to specify the conditions under which automatic (or manual) generation runback can be used to meet single (or multiple) contingency performance requirements and to make it clear that all facilities must always remain within applicable thermal and voltage ratings.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q37			
Commenter	**Yes**	**No**	**Comment**
Dominion		☑	For a single contingency, no generation adjustment should be allowed. For multiple transmission element contingencies, generation reduction (automatic or manual runback) may be allowed. Unit trip should only be allowed if a unit becomes unstable.
Duke Energy		☑	Runback should not be used if the disturbance caused you to exceed emergency ratings (i.e. thermal overload).
Ameren		☑	No generation runbacks should be allowed as long-term solutions for single contingency conditions.
Entergy	☑	☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runbacks should not be used to restore an element to within emergency ratings.
MISO	☑	☑	No, this should be the exception, not the rule. Yes, there are mine mouth plants with DC outlet lines, which must be runback if the DC line trips. There are also generators which used to serve large on site loads. The large loads are gone (plants retired) and generator outlet is limited. There are also some generators which have known contingent outlet limits and the generators are OK with runback, if the contingency occurs.
AECI	☑		We do not have the capability to have automatic runback at this time. However if an entity does have the capability to perform automatic runback than it should be allowed to prevent overloads. That would be the purpose.
Progress–Florida	☑		Provided events are confined to a single area (i.e., no cascading outages), automatic runback of generators should be allowed.
SERC EC DRS		☑	The question is not clear. Generation runback schemes are acceptable as long as emergency ratings are not violated. Runback schemes should not be used to restore an element to within emergency ratings.

Q37			
Commenter	**Yes**	**No**	**Comment**
Response: Industry comments strongly support allowing for the use of generator runback for single Contingencies. Generation runback will be permitted for all Contingencies, and the SDT has modified the standard language accordingly (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
ITC		☑	We believe that the BES should be able to operate for N-1 events without reliance on operating schemes. Assuming that some areas allow this, there should be criteria to evaluate the consequences of 2nd contingencies occurring during the runback. In addition, short-time ratings need to be confirmed which limit the time for runback. The system is at risk until the runback is completed and this risk must be evaluated and REQUIRED in the planning assessment.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view, including the requirement to remain within Facility Ratings during the course of the runback.			
KCPL		☑	All generators must have "firm" transmission outlet capacity.
Response: Industry comments strongly support allowing for the use of generator runback to prevent thermal overloads. The SDT has modified the standard language to clarify this view.			
ABB	☑	☑	No. Following a single contingency, all flows must be within some kind of established rating. After that, runback can be used to get under a longer-term rating. For multiple contingencies, some type of cross-tripping is OK, but runback is too slow and unreliable.
AECC		☑	Implementing an automatic runback scheme will only mask the impacts of the event. You want to know what happens when an event occurs not set up some psuedo fix that takes place before you know what the problem is.
Response: Industry comments strongly support allowing for the use of generator runback for single contingencies. The SDT has modified the standard language accordingly.			
BCTC	☑	☑	See our response to Question 36. In addition, since this runback is effectively a RAS/SPS with respect to protecting the transmission system from cascading, it must meet all the reliability requirements of a RAS.
Response: The SDT agrees that an automatic generation runback scheme is an SPS, and it must meet the applicable reliability requirements.			
PJM	☑	☑	Yes. At a minimum the emergency rating needs to be coordinated with the SPS timing.
Brazos Electric	☑		Can be including in a RAP or SPS with a long term CAP.
City Water Power and Light	☑		Coordination with neighboring systems is essential when considering generation redispatch.
ERCOT ISO CAISO	☑		1. Run back of generation should not result in tripping of firm load, 2. Power flow should be within the applicable ratings, 3. Frequency should be within the allowable limits
WECC	☑		Yes. Agree. Conditions for generation run back for N-1: 1) Run back of generation cannot result in

Q37			
Commenter	**Yes**	**No**	**Comment**
BPA TSGT TEP			tripping of firm load, 2) power flow should be within the time-limited equipment ratings, 3) frequency should be within allowable limits.
Northwestern Energy	☑		Yes, (1) if the failure of the runback scheme results in cascading, then it should not be allowed; (2) the power flow should be within the time-limited equipment ratings; and (3) the frequency should be within allowable limits.
Allegheny Power	☑		This could be permitted provided the run back will allow for the ability to prepare for the next operational contingency and not affect load.
AEP	☑		Ensure that the scheme is enabled to automatically runback for the problem conditions.
APPA	☑		Care must be taken to insure runbacks of one event will not cancel the effects of other runback plans in the same interconnections.
Central Maine Power HQTE National Grid NU NPCC RCS New England ISO NSTAR United Illuminating	☑		However, this should only be allowed where failure of an automatic runback that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
Exelon	☑		Run-back schemes should be allowed for certain single contingencies that can result in unit outlet constraints. Not all emergency ratings are thermal - some are relay or stability limits. In these instances, generator run-back should not be allowed.
FirstEnergy	☑		Yes, only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
FPL FRCC	☑		At a minimum the emergency ratings should allow sufficient time for the runback scheme to operate reliably
Georgia Transm.	☑		Generation curtailment should allow the system to operate within the facility capabilities and should not put the generator at risk of violating its NERC requirements during curtailment.
IESO	☑		Please see our response to Q36 for the rationale for allowing the runback scheme to operate. The conditions that need to be met in order to allow the scheme to operate depends specifically on what that SPS (runback scheme) is designed for. Some schemes are designed to operate upon detecting the opening of specific transmission lines, others are designed to operate upon detection of circuit loading reaching a particular threshold. There is no universal rule as to the conditions that must be met for a runback scheme to operate. The use of runback scheme is similar to using special operating procedure, such as cross tripping, operator instructions to open a circuit, etc. There might be design requirements to ensure the scheme meet certain performance criteria. However, these should be covered in the standards for special protection system. In TPL-001, the requirement would be to include simulation of the runback scheme operation only as the conditions that would prompt the

Q37			
Commenter	**Yes**	**No**	**Comment**
			scheme to operate occur, and a requirement to include SPS misoperation, i.e., failure to operate and operate when not initiated, as a contingency.
Manitoba Hydro	☑		I see no problem in using a runback scheme to prevent thermal overloads. Most emergency ratings are based on 30 minute values to allow for operator action. An automatic runback could be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values.
MEAG Power NCEMC SERC EC PSS SCE&G TVA	☑		The generator runback scheme should complete its action within the time allowed by the emergency ratings of elements that exceed their normal thermal ratings.
NERC TIS	☑		This is simply a recognition that the system operators will take action to return the system to a stable and secure operating posture following an event. This is also common practice in generator protection/controls for generators with multiple GSUs for loss of one of the GSUs.
New York ISO	☑		Testing scenarios will have to be developed on a case by case basis depending on the design of the SPS. There is not universal rule that can be made for these unique cases.
Progress–Carolinas	☑		If the rating is a 2 hour rating then the adjustment should be complete within 2 hours.
SRP	☑		The loss of transmission line (N-1) may require Gen drop to prevent instability or violation. Studies will need to be performed that study the congestion of generation and transmission corridors and loss of various elements.
Santee Cooper	☑		Generator runback schemes should be able to be implemented before emergency thermal rating time limits are exceeded.
SaskPower	☑		Several generation run back or generation rejection schemes are used in Saskatchewan to restore facility loading to with normal ratings. The costs of not using these schemes would involve substantial increased investments and environmental impacts unacceptable in the Saskatchewan Regulatory Jurisdiction. Conditions are determined on a case by case basis. However, the generation runback or generation rejection scheme should not exceed the normal operating reserve.
Seattle City	☑		Runback should be allowed to prevent a possible cascading outage which might result from the thermal overload, but only to that level needed to protect the equipment, to address the contingency, or to prepare for the next contingency. If the runback level is lower than the normal rating, it should be shown that this runback will not harm the stability of the system.
Southern Transm.	☑		Yes, as long as no emergency ratings are violated.
Tenaska	☑		So long as the performance requirements are met then this is not an issue.
Response: The SDT agrees with your comments.			
MRO	☑		Generally, the historical MRO practices and requirements have been to require that following a single

Q37			
Commenter	**Yes**	**No**	**Comment**
			contingency the loading of facilities are to be maintained within emergency ratings. Adjustments are allowed to move the system from conditions within emergency ratings to conditions within normal ratings. However, in a limited number of cases, the use of Special Protection Systems are used to initiate fast generation run back, generation rejection, or automatic tripping of a remote transmission facility to get below a longer term emergency rating (30 minutes or longer.) In some cases, these involve parts of the network where remote generation is connected to load where the costs of not using the SPS would involve substantial increased investments and environmental impacts. Requirement 3.5 needs more clarification. What rating should not be exceeded?
Response: The SDT agrees with your comment and has modified the language of R 3.5 for clarity. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
LADWP	☑		It was never disallowed under the current standards.
Response: The SDT believes that the current standards are silent on the use of SPS such as automatic generation runback. The standard language has been modified to explicitly identify the conditions under which an SPS may be used (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to place facilities in-service to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. Accordingly, the current draft standard language does not impose such a limitation on the use of SPS.			
ATC	☑		
CenterPoint	☑		
CPS Energy	☑		
ISO/RTO	☑		
Muscatine P&W	☑		Reasonable and workable.
SERC RRS OPS	☑		
Response: Thank you. Please see the Summary Response.			

The standard drafting team has considered that RAS or SPS may be allowable under certain situations for single Contingencies, but proposes that their use should be limited.

38) Q38. Do you agree that RAS or SPS may be allowed for single Contingencies? If not, please explain.

Summary Response: From the survey of industry responses regarding automatic readjustment of generation using SPS/RAS, the industry agrees that SPS/RAS may be allowed for single Contingencies. As a result, the SDT has modified the language in the standard such that it will allow the use of SPS/RAS for single or multiple Contingencies.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained

Q38			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	It makes the system too complex and less reliable. Single contingencies need to be handled without any fancy controls.
KCPL		☑	Tripping generation for single contingency other than GSU failure or fault is unacceptable.
LCRA		☑	Only until plans are implemented to address a single contingency-identified deficiency. In general, plans should always be developed to exit SPS or RAS when economically feasible
Central Maine Power National Grid New England ISO NSTAR United Illuminating	☑		Only allowed where the failure of an SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NU	☑		It is not recommended that an SPS be used in this situation, that over time, the proliferation of SPSs may degrade system reliability and unduly complicate system operations. If allowed an SPS should only be used where the failure of the SPS that is not functionally redundant would not have significant adverse impact on the Bulk Electric System.
NPCC RCS	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.

<table>
<tr><th colspan="4">Q38</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td>SCE&G</td><td>☑</td><td></td><td>A RAS or SPS should be allowed for single contingencies if its failure or misoperation can be compensated for during the time allowed by the emergency ratings of the elements that exceed their normal thermal ratings.</td></tr>
<tr><td colspan="4">Response: The Industry response to this question has prompted the SDT to change the language to allow SPS/RAS for single or multiple Contingencies. The standard language now lists qualifiers of the use of SPS/RAS, listed in Requirements R3.5.1, R3.5.2 and R3.5.3.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained</td></tr>
<tr><td>City Water Power and Light</td><td></td><td>☑</td><td>SPS use should be limited and SPSs should be of a temporary nature. A mitigation plan with a timeframe for implementation should accompany all SPSs and RASs.</td></tr>
<tr><td>ITC</td><td></td><td>☑</td><td>We wouldn't agree to this without knowing what you mean by limited use. RAS or SPS as a common practice does not "raise the bar" in planning standard. An RAS or SPS should be allowable as a temporary measure to allow one to meet the standard and two to protect the components of the BES. When used in this capacity, a plan should be being either developed or implemented such that the RAS or SPS can be removed from service.</td></tr>
<tr><td colspan="4">Response: The overall Industry response prompted the SDT to not include the qualifier about temporary use of SPS/RAS.</td></tr>
<tr><td>CPS Energy</td><td></td><td>☑</td><td></td></tr>
<tr><td colspan="4">Response: See summary response.</td></tr>
<tr><td>AECC</td><td></td><td>☑</td><td>this question is not clear. are you asking if the SPS/RAS be studied as a contingency or if the SPS/RAS is a viable solution for impacts caused by a contintgency. In either case SPS/RAS impacts and effectiveness needs to be evaluated. Especially if they are used as a mitigation for contingency impacts. It should be knownif the SPS/RAS is effective for the model being studied and if not another mitigation should be determined</td></tr>
<tr><td colspan="4">Response: The SDT is attempting to explicitly state under what conditions a SPS/RAS can be used to mitigate undesirable System response to single Contingency events. The current standards are silent on this issue.</td></tr>
<tr><td>Ameren</td><td>☑</td><td></td><td>Yes, but only as interim operating procedures until the limiting facilities can be uprated or unloaded. SPS or RAS should be allowed to trip non-firm (energy only) generation to keep facility loadings within ratings.</td></tr>
<tr><td colspan="4">Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2 and R3.5.3. The Standard does not differentiate performance for different generation types.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:</td></tr>
</table>

Q38			
Commenter	**Yes**	**No**	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained			
Progress–Florida	☑		This requirement is addressed in PRC-005 and these requirements should not be addressed again in this Standard. However, the use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The conditions for the use and application of SPS/RAS are addressed in the TPL Standards. The SDT does not agree that the PRC Standards addresses the use of SPS/RAS.			
Southern Transm.	☑		RAS and SPS should be defined such that they may only be used for low probability events.
Response: The overall response from the Industry prompted the SDT to change the language in the Standard to allow SPS/RAS for all single and multiple contingencies with the qualifiers of Requirements R3.5.1, R3.5.2, and R3.5.3. There are no qualifications of the use of SPS/RAS based on the probability of the contingency. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained			
IESO	☑		SPS and RAS should be allowed for single contingencies. However, a more fundamental requirement is that the SPS (and RAS) should generally be regarded as a stop gap measure before planned transmission expansion or reinforcement becomes available. SPS should in general not be used as a substitute for transmission facilities.
New York ISO	☑		As stated previously SPSs should only be a temporary solution used to protect elements prior to a permanent solution implementation.
WPS	☑		The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: The overall Industry response prompted the SDT to allow the use of SPS/RAS as a permanent Corrective Action measure and not just as a temporary measure.			
Brazos Electric	☑		
Dominion	☑		
ERCOT ISO	☑		Agree

Q38			
Commenter	**Yes**	**No**	**Comment**
Northwestern Energy	☑		
AECI	☑		
Allegheny Power	☑		
AEP	☑		As long as they are automatic.
APPA	☑		As the SDT has said under certain situations.
ATC	☑		
APS			
BPA	☑		
BCTC	☑		
CAISO	☑		Agree
CenterPoint	☑		
Duke Energy	☑		RAS and SPS are economical solutions that planners ought to be able to use.
Entergy	☑		RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Exelon	☑		
FirstEnergy	☑		As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
FPL FRCC	☑		The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Georgia Transm.	☑		
HQTE	☑		A SPS may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. An SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ an SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits.
ISO/RTO	☑		
Manitoba Hydro	☑		MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MEAG Power	☑		

Q38			
Commenter	**Yes**	**No**	**Comment**
MISO	☑		
MRO	☑		
Muscatine P&W	☑		
NERC TIS	☑		
NCEMC	☑		
PJM	☑		
Progress–Carolinas	☑		
SRP	☑		As long as Non-Consequential Loss of Load is not a solution for single contingencies (N-1).
Santee Cooper	☑		
SaskPower	☑		
Seattle City	☑		
SERC EC DRS	☑		
SERC EC PSS	☑		
SERC RRS OPS	☑		
Tenaska	☑		
TVA	☑		TVA does not allow generator tripping for a single contingency. However, we recognize that there are certain instances for which this makes practical and economic sense.
TSGT	☑		
TEP	☑		
WECC	☑		
Response: Thank you. Please see the Summary Response.			

39) Q39. Please describe the limitations that you believe should be placed on the use of RAS or SPS for single Contingency events.

Summary Response: Requirement R3.5 has been written such that it allows RAS or SPS for single or multiply Contingencies with limitations described in Requirements R3.5.1 through R3.5.3. Requirement R3.5.2 allows for "regulatory or statutory requirements" that may prohibit or limit the use of RAS or SPS.

In addition, most responders said, or implied, that the failure of SPS/RAS schemes should be studied. Most said that the failure of the schemes should not cause cascade, with some suggesting that there shouldn't be any Non-Consequential Load Loss. The SDT believes that failure of SPS should not be used to establish requirements in the TPL-001-1 standard. Instead, this standard sets requirements when SPS can be used, and relies on the relevant PRC standards to set the requirements for studies and designs to implement the SPS. In response to those that commented regarding existing RRO standards becoming more stringent than the resulting North American standards, there are provisions to allow for regions to have and implement more restrictive standards.

Q39	
Commenter	**Comment**
ABB	They could be used in the short term until a permanent fix is available. Limit to <5 years.
Ameren	SPS and RAS should be used only as interim operating procedures to mitigate single contingency events until the limiting facilities can be uprated or unloaded. SPS and RAS should be allowed to trip non-firm (energy only) generation as needed to keep facility loadings within ratings.
Northwestern Energy	RAS or SPS should not be allowed for non three phase single line faults. If cascading could result from the failure of the RAS to operate properly, then redundancy should be required.
HQTE	See response to Q38.
ITC	Temporary in nature.
KCPL	RAS/SPS should not limit generation output for N-1 conditions.
LCRA	Short-term with exit plans; Loss of significant generation or load resulting from SPS /RAS action.
Manitoba Hydro	An automatic runback should be accomplished in 5-15 minutes depending on the ramp rate of the generator. The runback scheme may allow higher emergency ratings depending on the rating methodology. At no point would emergency ratings be exceeded and at the end, loading would be within normal values. Generator tripping should be allowed. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. MH sees no reason to limit the application of SPSs. The SPS is a viable planning option that allows large savings in cost in stability limited system where there is no need to increase thermal capability.
MRO	The MRO believes the MRO systems are presently designed to meet system performance, in some cases, with the use of SPS to initiate fast generation runback, generation rejection, and automatic tripping of a remote transmission facility for a single contingency event. The fast generation runback or generation rejection should not exceed the normal operating reserve of the generation reserve sharing pool to which the planner belongs or of the planner itself if the planner self-provides generation reserves.

Q39	
Commenter	**Comment**
New York ISO	Must be temporary, approved by the NYSRC, tested annually with evidence of preventive maintenance submitted annually.
NPCC RCS	See response to Q38.
Southern Transm.	Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5.	
Brazos Electric City Water Power and Light	Taken directly from the ERCOT operating Guides for RAPs and SPSs: Any RAP must meet the following requirements: a. Coordinated and approved with the owners and operators of facilities included in the RAP. b. Use is limited to the time required to construct replacement Transmission Facilities. However, the RAP will remain in effect, if replacement Transmission Facilities have been determined by the Control Area Authority to be impractical. c. Complies with all applicable ERCOT and NERC requirements. d. ERCOT develops and posts a methodology to include the RAP in the Total Transfer Capability (TTC) calculations, if appropriate. e. Clearly defines and documents operator actions. f. Includes the option for the transmission operator to override the procedures if the RAP will not improve system reliability. g. Operators must be trained in RAP implementation. For SPSs 13. Special Protection Systems (SPS) are protective relay systems designed to detect abnormal ERCOT System conditions and take pre-planned corrective action (other than the isolation of faulted elements) to provide acceptable ERCOT System performance. SPS actions include among others, changes in demand, generation, or system configuration to maintain system stability, acceptable voltages, or acceptable Facility loadings. An SPS does not include underfrequency or undervoltage load shedding. A Type 1 SPS is any SPS that has wide-area impact and specifically includes any SPS that a) is designed to alter generation output or otherwise constrain generation or imports over DC Ties, or b) is designed to open 345 kV transmission lines or other lines that interconnect TDSPs and impact transfer limits. Any SPS that has only local-area impact and involves only the Facilities of the owner-TDSP is a Type 2 SPS. The determination of whether an SPS is Type 1 or Type 2 will be made by ERCOT upon receipt of a description of the SPS from the SPS owner. Any SPS, whether Type 1 or Type 2, shall meet all requirements of NERC Standards relating to SPSs, and shall additionally meet the following ERCOT requirements: • The SPS owner shall coordinate design and implementation of the SPS with the owners and operators of Facilities included in the SPS, including but not limited to Generation Resources and HVDC ties. • The SPS shall be automatically armed when appropriate. • The SPS shall not operate unnecessarily. To avoid unnecessary SPS operation, the SPS owner may provide a

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Commenter	**Comment**
	real-time status indication to the owner of any Generation Resource controlled by the SPS to show when the flow on one or more of the SPS's monitored facilities exceeds 90% of the flow necessary to arm the SPS. The cost necessary to provide such status indication shall be allocated as agreed by the SPS owner and the Generation Resource owner. • The status indication of any automatic or manual arming of the SPS shall be provided as SCADA alarm inputs to the owners of any facility(ies) controlled by the SPS.. • When a Transmission Operator (TO) removes a SPS from service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the unavailability of the SPS and notify the Market. When a SPS is returned to service, the TO shall immediately notify ERCOT operations. ERCOT shall modify its reliability constraints to recognize the availability of the SPS. 14. The owner(s) of an existing, modified, or proposed SPS shall submit documentation of the SPS to ERCOT for review and compilation into an ERCOT SPS database. The documentation shall detail the design, operation, functional testing, and coordination of the SPS with other protection and control systems. • ERCOT shall conduct a review of each proposed SPS and each proposed modification to an existing SPS. Additionally, it shall conduct a review of each existing SPS every five years, or sooner as required by changes in system conditions. Each review shall proceed according to a process and timetable documented in ERCOT Procedures and posted on the ERCOT website. • For a proposed Type 1 SPS, the review must be completed before the SPS is placed in service, unless ERCOT specifically determines that exemption of the proposed SPS from the review completion requirement is warranted. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. The implementation schedule must be confirmed through submission of a Service Request to ERCOT. • For a proposed Type 2 SPS, the SPS may be placed into service before completion of the ERCOT review, with advanced prior notice to ERCOT in the form of a Service Request. The timing of placing the SPS into service must be coordinated with and approved by ERCOT. Existing SPSs that have already undergone at least one review shall remain in service during any subsequent review, and proposed modifications to existing SPSs may be implemented, upon notice to ERCOT, and approval of ERCOT before completion of the required ERCOT review. • The process and schedule for placing an SPS into service must be consistent with documented ERCOT Procedures. The schedule must be coordinated among ERCOT and the owners of any facility(ies) controlled by the SPS, and shall provide sufficient time to perform any necessary testing prior to its being placed in service. • An ERCOT SPS review shall verify that the SPS complies with ERCOT and NERC criteria and guides. The review shall evaluate and document the consequences of failure of a single component of the SPS, which would result in failure of the SPS to operate when required. The review shall also evaluate and document the consequences of misoperation, incorrect operation, or unintended operation of an SPS, when considered by itself, and without any other system contingency. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. The current review results shall be kept on file and supplied to NERC on request within thirty (30) days. • As part of the ERCOT review and unless judged to be unnecessary by ERCOT, the appropriate ROS working groups such as the Steady State Working Group, the Dynamics Working Group, and/or the System Protection Working Group shall review the SPS and report any comments, questions, or issues to ERCOT for resolution. ERCOT may work

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Commenter	**Comment**
	with the owner(s) of facilities controlled by the SPS as necessary to address all issues. • ERCOT shall develop a methodology to include the SPS in the Commercially Significant Constraint (CSC) limit calculations, if appropriate. • ERCOT's review shall provide an opportunity for and include consideration of comments submitted by Market Participants affected by the SPS. 15. SPS owners shall notify ERCOT of all SPS operations. Documentation of SPS failures or misoperations shall be provided to ERCOT using the Relay Misoperation Report located in Section 6 of these Operating Guides. ERCOT shall conduct an analysis of all SPS operations, misoperations, and failures. If deficiencies are identified, a plan to correct the deficiencies shall be developed and implemented. 16. For each SPS, the owner shall either identify a preferred exit strategy or explain why no exit strategy is needed to ERCOT. This shall take place according to a timetable documented in ERCOT Procedures and posted on the ERCOT website. Once an exit strategy is complete and a SPS is no longer needed, the owner of an existing SPS shall notify ERCOT, using a Service Request, whenever the SPS is to be permanently disabled, and shall do so according to a timetable coordinated with and approved by ERCOT and the owners of all facilities controlled by the SPS
Response: The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Dominion	For single contingency events, a SPS scheme should not result in loss of load.
Response: Non-Consequential Load Loss is not allowed for single Contingency events.	
ERCOT ISO CAISO	RAS or SPS should generally be regarded as a stop gap measure before transmission expansion or reinforcement becomes available. It should not be used as a substitute for transmission facilities.
Response: Your suggestion was seriously considered but restrictions were limited to those sub-requirements of Requirement R3.5. The SDT anticipates that ERCOT will be able to maintain the existing requirements that you suggest. Requirement R3.5.2 allows for "regulatory or statutory requirements" which may limit RAS or SPS.	
Allegheny Power	The use of these system should be limited and not used as a preferred solution and also be approved by a stringent review process through the RTO & RE.
AEP	Should be allowed as long as they have been approved by the applicable Regional Reliability Organization.
APPA	See Question 36.
BCTC	RAS should be permitted when the system performance conforms with the performance requirements laid out in the tables. Generator tripping should be permitted for single contingency events. R3.6 proposes to limit generator tripping for single contingencies except for certain conditions which are not listed. Without knowing what these conditions might be, we find ourselves speculating on what might be proposed. On the 10 October 2007 conference call, it was suggested that there are concerns regarding generator reserves and loss of reactive capability. We have some observations regarding these concerns. With respect to reserves, some concerns would also apply to runback, since units on runback could not also be on AGC and could not be reallocated to AGC until the transmission contingency is returned to service. There was also a concern regarding tripping of steam units and the delay in bringing them back on line. This is a resource adequacy issue that should be addressed with the customer, not a transmission reliability issue. Regarding the loss of reactive capability, this would be addressed by

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Commenter	**Comment**
	the post mitigation plan studies to demonstrate that the reactive reserves meet the requirements, whatever they are determined to be. We would generally expect that the reduction in MW transfers would reduce the need for reactive support, so the new condition might not require the reactive support. Nevertheless, the post mitigation studies will address this. Therefore, we conclude that these concerns are not applicable to transmission planning standards. BCTC plans and operates a transmission system that interconnects generation comprised of about 90% hydroelectric. Often the extreme generation patterns for which we consider generator tripping occur for a limited time period during the year at off peak. These would be during high runoff and/or light local load periods. For these conditions, there is typically plenty of other generation that can be used as reserves for generator tripping. BCTC currently strives to avoid use of RAS for N-1, especially on the 500 kV transmission system. However, for example, if avoiding generator tripping were to trigger the need for hundreds of km of 500 kV transmission line for an off peak operating condition or a low capacity factor or intermittent resource, we would likely consider RAS, especially for transmission radial to the generator. In the lower voltage systems we often have consequential loss of small generators and consider generator tripping for radial lines and local networks. In most cases, this generator loss is addressed through sensitivity studies and discussions with generator owners and transmission customers with respect to the costs they are willing to incur and what is required by Resource Planners to meet their planning criteria. Operating reserves requirements are also a consideration. Any loss of generation due to tripping or ramping that is less than the amount lost due to consequential loss should be acceptable without question. In summary, we would be prepared to review and comment on a proposal from the SDT on limitations on generator tripping. BCTC suggests that the SDT list the limitations rather than the permitted conditions and that these limitations should also apply to generator ramping.
Georgia Transm. SERC EC DRS	None.
Muscatine P&W	As long as they work and are reasonable - none. (See Q43 Comment #3)
MISO	The use of SPS/RAS may be the appropriate transmission system design. If it is economic to mitigate the SPS, then upgrades should be made.
Response: See the summary response.	
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	Only allowed where SPS failure would not have significant adverse impact on the Bulk Electric System; non-Consequential loss of load should be allowed up to an amount potentially specified in the standard.
Response: See the summary response. As to your suggestion on Non-Consequential Loss of Load, it is prohibited for single Contingencies and is not prohibited for multiple Contingencies.	
Duke Energy	You should not have any wide area cascading if the RAS or SPS fails to operate as expected, or operates when it shouldn't.

Q39	
Commenter	**Comment**
Response: See the summary response: PRC standards address SPS failure.	
Entergy	RAS or SPS may be allowed for single contingencies when they aid in meeting System Performance requirements. RAS and SPS should not be used to restore an element to within emergency ratings.
Response: See the summary response. Requirement R3.5.1 restricts RAS/SPS such that facility ratings must be honored at all times.	
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event.
Response: See the summary response. Non-Consequential Load Loss is not permitted for single Contingency events.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Response: See Requirement R3.5. There are no longer any limitations on the use of SPS as long as they meet this criteria.	
IESO	Please see comments provided under Q38, above, regarding the use of SPS not as a substitute for transmission facilities. In addition, there should be requirements to simulate failure of SPS operation as a contingency in addition to the initiating single contingency. In cases where an SPS is intended to achieve acceptable stability performance which can affect interconnection reliability, the SPS should be classified as BES impactive and as such, redundancy may be required. When redundancy is provided, simulation of SPS failing to operate may be waived.
Response: Your suggestions were considered but the only limitations to RAS/SPS are those listed as sub-requirements of Requirement R3.5. PRC standards address SPS failure.	
MEAG Power NCEMC SERC EC PSS SERC RRS OPS SCE&G TVA	RAS or SPS should meet the same criteria as any protection system.
Response: See summary response as regards to planning standards. The PRC standards for SPS will be maintained as you have suggested.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: The SDT agrees that the PRC standards address performance and may need to be updated.	
ReliabilityFirst	The requirements for the use of SPS and RAS should be contained in a separate standard. That standard should dictate when the RAS and SPS can be used. The planning studies would then simulate those conditions.
Response: This was considered but the consensus was to keep requirements in TPL-001-1. RAS/SPS is allowed as per Requirement R3.5 and its sub-requirements.	
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain stable with no violations.
Response: The SDT agrees and Non-Consequential Load Loss is not permitted.	
Santee Cooper	There should be no stability impacts, and system security must be maintained. RAS or SPS should meet the same criteria as any protection system.

Q39	
Commenter	**Comment**
Response: See the summary response. The PRC standards address protection system criteria.	
SaskPower	Delegate this issue to the Planning Coordinators.
Response: See the summary response. The PC is just one of many applicable functional entities.	
Seattle City	All RAS or SPS schemes should be evaluated to determine the impact on the interconnected system. Actions that derate transfer paths should not be allowed unless essential to protecting equipment or anticipating the next contingency.
Response: See the summary response. The SDT expects that all SPS/RAS will still be subject to the regional scrutiny that you have suggested.	
AECC	See comment to Q38.
Response: See response to Q38.	
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
Response: The standard allows for RAS/SPS as per Requirement R3.5 but these types of corrective actions are expected to meet the performance requirements as per the tables.	
WECC BPA TSGT TEP	Based on the interpretation of the above question, we are providing two responses to this question. The first responds to the limitations placed on RAS, regardless of what action the RAS initiates. The second response specifically addresses RAS that trips generation. Response 1: RAS should be allowed for single contingency events. Any sort of RAS should be permitted, but there should be a review of the RAS. If the local entities agree to the RAS, it should be allowed. This addresses cost vs. benefit balance. Entities affected should be the ones that determine the best solution for their situation. Response 2: Generation tripping can be used for single contingency if such application can be demonstrated through transmission planning studies that: • The generation tripping is planned and controlled ("planned and controlled" means a pre-planned action(s) based on predetermined system conditions that take corrective measure(s) to maintain acceptable system performance). • The generation tripping does not result in non-consequential load loss. • System frequency should be within allowable limits. • System voltage dip and deviation should be within allowable limits. • The generator owner(s) agrees to the tripping as planned.
Response: Requirement R3.5 allows for the use of SPS and RAS and Requirement R3.5.2 would allow for the kinds of review that you're suggesting.	

40) 40. When RAS or SPS are allowed, what conditions should be met when these systems are used in system adjustments to meet performance requirements?

Summary Response: There was a wide variety of responses that described the conditions that should be met when an RAS or SPS is applied but the majority of the responses can be characterized as follows:

- Requirements for SPS are outlined in the PRC standards
- Maintain System Stability
- Prevent cascading
- Prevent loss of load
- Should be used as a short-term mitigation solution

Other suggestions include:

- Non-Consequential Loss of Load should not be allowed for single Contingencies (N-1)
- Allow to prepare for next Contingency
- If an SPS is used to solve a single Contingency problem, then full redundancy should be required.
- Generator tripping or runback and reconfiguration should be allowed for lower probability single Contingency events such as bus faults.
- SPS not be used for events that are more likely to occur.
- Should not constitute a long-term Corrective Action Plan to address deficiencies.

The SDT has modified Requirement R3.6 (now Requirement R3.5) to specify the conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements and to make it clear that all Facilities must always remain within applicable thermal and voltage ratings.

The following requirements have been changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

Q40	
Commenter	**Comment**
Ameren	RAS and SPS should be allowed only as an interim operating procedure to mitigate single contingency conditions or to mitigate multiple contingency events on a long-term basis. The RAS or SPS must be effective in mitigating the contingencies and can be implemented within the required operating time.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not	

Q40	
Commenter	**Comment**
impose such a limitation on the use of SPS.	
Brazos Electric	See above.
BCTC	See Q39. Also, WECC RAS Reliability requirements must be met for new systems.
Central Maine Power HQTE National Grid New England ISO NU NPCC RCS NSTAR United Illuminating	System must remain stable with acceptable voltages and all equipment within applicable emergency limits.
Duke Energy	See response to Q36 and Q37 above. No additional conditions beyond meeting the performance requirements.
Entergy	Following a contingency, power flows on lines should be within their emergency ratings, voltages should be at adequate levels and system should be stable.
FirstEnergy	As long as thermal, voltage, and stability requirements are met, RAS or SPS should be allowed provided it does not shed load for a single contingency event, and only if the Transmission Owner has documented short term ratings that would not be exceeded during the runback.
JEA	RAS/SPS should not limit generation output for N-1 conditions.
Manitoba Hydro	1) Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change should be limited to that amount that can be accomplished within the allowed readjustment period. Due consideration should be given to start up time and ramp rates of the units. 2) Generator tripping should be added to requirement R3.5 in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 3) Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, should be limited to those which could be switched during the allowed readjustment period. 4) Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. 5) Adjustment of phase shifters to the extent possible within the allowed readjustment period. 6) An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 7) Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 8) Automatic tripping of interruptible load or curtailment of or redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
MISO	SPS may be used if it maintains similar level of system reliability and security as transmission upgrades.
MRO	SPS are often used in the MRO area to avoid unnecessary expenditures and environmental impacts. SPS are sometimes used to prevent instability. The SPS may initiate fast generation run back, automatic generation rejection, or automatic tripping of a facility for a remote event. The MRO notes that the scheme must be automatic, fast acting, consistent with short term equipment ratings. The MRO notes the following general conditions for adjustments, that

Q40	
Commenter	**Comment**
	perhaps would be useful in designing performance requirements for allowable system adjustments in addition to the description in Question 39: 1. Generation adjustments - Reducing or increasing generation while keeping the units on-line or by bringing additional units on line. The amount of generation change is limited to that amount that can be accomplished within the allowed readjustment period. Due consideration shall be given to start up time and ramp rates of the units. 2. Capacitor and reactor switching - The number of capacitors and reactors, which may be switched, is limited to those which could be switched during the allowed readjustment period. This includes those capacitors and reactors that would be switched by automatic controls within the same period. 3. Adjustment of load tap changers (LTCs) to the extent possible within the allowed readjustment period. This includes both LTCs which would automatically adjust and those under operator control which could be adjusted within the readjustment period. 4. Adjustment of phase shifters to the extent possible within the allowed readjustment period. 5. An increase or decrease to the flow on HVDC facilities to the extent possible within the allowed readjustment period. 6. Transmission reconfiguration - Automatic tripping of transmission lines or transformers to the extent possible within the allowed readjustment period. 7. Automatic tripping of interruptible load or curtailment of or pre-determined redispatching of Firm Transmission Service to the extent possible within the allowed readjustment period.
Muscatine P&W	Reasonable and workable. (See Q43 Comment #3)
NERC TIS	No special conditions required as long as the RAS or SPS are tested to meet the performance requirements.
Seattle City	Actions should be intended to address contingency, prevent damage, or prepare for next contingency.
SERC EC DRS	No additional conditions except meeting performance requirements.
Southern Transm.	If an SPS is used to solve a single contingency problem, then full redundancy should be required. Generator tripping or runback and reconfiguration should be allowed for lower probability single contingency events such as bus faults; we suggest that SPS not be used for events that are more likely to occur.
Tenaska	The system, following the use of an RAS or SPS in response to a single contingency, shall meet the performance requirements.
WECC BPA TSGT TEP	System adjustment involves operator intervention that would be beyond the time frame of RAS operation. Therefore, if a unit is already dropped during RAS or SPS action, it should be assumed to be off-line during system adjustment period.

Response: Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q40	
Commenter	**Comment**
R3.5.1. All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained.	
City Water Power and Light	Maintain system stability, prevent loss of load and prevent cascading outages.
Response: The SDT agrees with your comment and has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple contingency performance requirements. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained.	
ERCOT ISO CAISO	1. RAS or SPS must be simple and manageable. 2. Number of contingencies triggering a RAS or SPS should be very limited (4 allowed by CAISO). 3. RAS or SPS should generally monitor only local facilities that are either directly connected to the plant or one bus away.
Response: The SDT agrees with your comment in (1) and believes this is covered in the requirements of the PRC standards. Based on the majority of industry responses, the SDT has modified Requirement R3.6 (now Requirement R3.5) to specify conditions under which manual and automatic generation runback and tripping can be used to meet single and multiple Contingency performance requirements for the steady state portion of the Planning Assessment. Applying additional requirements needs to be done as a regional difference. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1.** All Facilities shall be operating within their Facility Ratings. **R3.5.2.** Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3.** A sustainable, stable, operating condition is maintained.	
Northwestern Energy	RAS or SPS should meet performance requirements including reserve requirements.
Allegheny Power	The system should remain stable, reliable, allow for operational preparation for the next contingency and failure of the RAS/SPS should not lead to a cascading event.
AEP	They include redundancy and their failure does not result in cascading.
APPA	Maintain system stability and prevent the loss of load.
SRP	Non-Consequential Loss of Load should not be allowed for single contingencies (N-1) and the system must remain

Q40	
Commenter	**Comment**
	stable with no violations.
Response: The SDT agrees.	
FPL FRCC	The performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. If the proposed TPL standard is adopted the contingency references in PRC-012-0 would need to be updated.
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Georgia Transm.	PRC Standards
MEAG Power NCEMC SERC EC PSS TVA	The conditions required by SPS standards (PRC).
Santee Cooper	There should be no stability impacts, and system security must be maintained. The requirements are outlined in PRC-015,016, and 017.
SERC RRS OPS	The requirements are outlined in PRC-015, 016, and 017.
SCE&G	The conditions required by SPS Reliability Standards.
Response: The SDT has considered your comments and concludes that the PRC standards describe the performance requirements for SPS but do not specify how the SPS requirements are applied to the Planning Assessment	
IESO	As indicated in the comments provided under Q38 and Q39, the conditions to simulate operation of the RAS and SPS would depend on the conditions they are designed to protect. We do not believe such conditions can be generalized.
ITC	This should be limited to the time until a physical solution is possible (i.e., a temporary solution).
WPS	The use of RAS or SPS should not constitute a long-term Corrective Action Plan to address deficiencies. The use of RAS and SPS should be limited to that period of time necessary to implement expansion of facilities to address the deficiency.
Response: Industry comments do not support the use of runback only as an interim measure. The current draft standard language does not impose such a limitation on the use of SPS.	
LCRA	Systems must have a balance between security and dependability. System must be reviewed annually or as system conditions change.
New York ISO	This would be dependent on the characteristics of each unique protection scheme.
Response: The SDT agrees with your comment and believes this is covered in the requirements of the PRC standards.	
Progress–Florida	The use of RAS or SPS should be allowed as necessary for any single contingency event, provided that such use does not result in cascading outages. It should be noted that the performance requirements for SPS are appropriately stated in standards PRC-012-0 and PRC-015-0. Revision of the existing TPL standards will require updating of the contingency references in PRC-012-0.
Response: Please see Requirement R3.5. The use of SPS is allowed for generation tripping or runback as long as the criteria is met	
AECC	See response to Q38.
Response: See response to Q38.	

Q40	
Commenter	**Comment**
SaskPower	Delegate this issue to the Planning Coordinators.
Response: The SDT believes that it should be a coordinated effort between the Planning Coordinator and the Transmission Planner.	

G) General Questions

41) Q41. If you are aware of any regional variances that would be required as a result of these standards, please identify them here.

Summary Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard. The standard has been modified with respect to the issue of generation tripping and that should reduce or eliminate the stated level of concern and may make a regional variance unnecessary.

The following requirement was changed due to industry comments:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy as long as Facility Ratings are not exceeded.~~if the following conditions are met:

Q41			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	
Brazos Electric		☑	
Dominion		☑	
E ON US		☑	
AECI		☑	
Allegheny Power		☑	
AEP		☑	
CenterPoint		☑	
CPS Energy		☑	
Duke Energy		☑	
Entegra			
Entergy		☑	
FirstEnergy		☑	
FPL FRCC		☑	No, if the comments to the above questions are incorporated. The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. The adequacy of the existing TPL standards as they apply to the FRCC System have been extensively documented.

Q41			
Commenter	**Yes**	**No**	**Comment**
Georgia Transm.		☑	
IESO		☑	
ITC		☑	Variances should not be a reason to change the standard (lower the bar).
KCPL		☑	
MISO		☑	
National Grid		☑	We're not aware of any at this time. However, future modifications of the standard may highlight a need for regional variances.
New York ISO		☑	
PJM		☑	
Progress–Florida		☑	No, but PEF reserves the right to apply for variances based on the completed version of this or any other standard.
Santee Cooper		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
TVA		☑	
WPS		☑	
Central Maine Power New England ISO NU NSTAR United Illuminating	☑	☑	Unsure due to ambiguities in the standard. Depending upon the final standard, New England may need exceptions for existing facilities or allowance for a transition period to develop a compliance plan.
HQTE NPCC RCS	☑	☑	Until section R3.6.1 is finalized, we will be unable to determine whether a regional variance is required.
Response: Few comments were received indicating that regional variances would be required although some pointed out that variances may be required depending on the final version of the standard.			
Manitoba Hydro	☑	☑	MH does not like the idea of a long transition period. Either NERC adopts the concept of generation rejection or the MRO will need to submit a regional variation. I much prefer the planned loss of generation via an SPS rather than via out-of-step tripping as proposed in the Table 2. In certain

Q41			
Commenter	**Yes**	**No**	**Comment**
			areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, removing one SPS will require new 500 kV transmission between Winnipeg and Minneapolis at a cost of $1 billion to MRO utilities.
BCTC	☑		WECC may require a regional difference for generator tripping depending on the conditions imposed in R3.6.1. Other regional variances would not necessarily be in the context of regional difference as defined in the Standards Manual, but rather exceptions for long weak systems for which it is not economic to meet criteria applicable to tightly interconnected systems.
ERCOT ISO CAISO	☑		ISO relies upon tripping of generators to meet single contingency performance requirements. ISO also relies upon planned and controlled load shedding for the proposed Planning Events P4 and P5.
LADWP	☑		Too many to be listed with the separation above and below 300kV being the worst one that will undermine the overall reliability of the electric system in North America. Another major omission in this proposed standard is the complete lack of recognition of the importance of post-transient requirements. Mixing commercial (firm or non-firm transactions, etc.) and reliability in transmission planning criteria would be in conflicts with WECC rules and practices.
MRO	☑		If the SDT proceeds with an approach that does not allow generation rejection for contingencies, the MRO will need to submit a regional difference. In certain areas of the MRO that are stability limited because of long lines to bring generation at the energy source (such as mine mouth plants, hydro plants, etc.) to the load, generation rejection is used to return from an emergency state to a normal state. If generation rejection is not allowed in these cases, extraordinary cost and extraordinary negative environmental impacts will result. As an example, if one particular SPS is removed, new 500 kV transmission will be required between Winnipeg and Minneapolis at a cost of $1billion to the customers of MRO utilities.
NERC TIS	☑		There may be some in the application of RAS or SPS for N-1 contingencies.
Northwestern Energy	☑		WECC allows N-1 generator tripping, and the transmission systems have been designed around this criteria. Moving away from this criteria is not necessary, and for critical N-1 events, redundancy is in place.
WECC BPA TSGT TEP	☑		Yes. WECC allows tripping of generators to meet single contingency performance requirements. WECC also allows planned and controlled load shedding for the proposed Planning Events P2-1, P2-2, P3, P4 and P5, although we agree with the proposed requirements for P4 due to the higher probability of occurrence. If the standard does not allow for non-consequential load shedding of 300 kV and above for P5 scenarios, WECC will develop a regional variance".
Response: The standard has been modified with respect to the issue of generation tripping that should reduce the stated level of concern and may make a regional variance unnecessary.			

Q41			
Commenter	**Yes**	**No**	**Comment**
R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
LCRA	☑		See ERCOT Planning Criteria. Also, through the regional coordinators, NERC recently conducted a survey of transmission planners/owners regarding use of more stringent criteria used in their own systems. The std. drafting team should include a review of the survey results and incorporate into this NERC std as necessary.
Response: The SDT will review the survey.			
MEAG Power	☑		Facilities rating methodology are different from region to region and company to company.
Response: Ratings methodologies are not covered in this standard.			
AECC	☑		I am more concerned about the regions performing studies consistently than identifying regional variences. My company sits stradle the Southwest Power Pool and SERC. There are considerable difference between the two when it comes to study criteria, assumptions, and how studies are performed. These differences have led to situations where it is near impossible to get models and perform studies near the seams that produce results in which you can have confidence and are comparable. The Southwest Power Pool and its members do a very good job of analyzing and evaluating their region. SPP has criteria that specifically requires EtE analysis and the process used to develop their Transmission Expansion Plan contains treatment of SPS/RAS schemes as mitigations.
Response: The SDT recognizes the regional differences that can exist. However, resolution of all regional variances is outside the scope of the SDT.			
APPA	☑		The WECC will probably have a couple.
ATC	☑		
City Water Power and Light	☑		
ISO/RTO	☑		
PRPA	☑		
Progress–Carolinas	☑		
Response: Thank you.			

42) Q42. If you are aware of any conflicts between the proposed standards and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement, please identify them here.

Summary Response: Few comments were received indicating conflicts between the proposed standard and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement. A few potential issues were identified in areas of the standard that have been modified in the second posting. These areas will need to be re-assessed based on the specific revisions made.

The following requirements were changed due to industry comment:

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy as long as Facility Ratings are not exceeded.~~if the following conditions are met:

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q42			
Commenter	**Yes**	**No**	**Comment**
ABB		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
AECC		☑	
Ameren		☑	The proposed standard, as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standard should clearly state that the standard does not apply to non-firm generation.
City Water Power and Light		☑	
E ON US		☑	
ERCOT ISO		☑	Not aware of any.
AECI		☑	
Allegheny Power		☑	
AEP		☑	
APPA		☑	
BCTC		☑	
CAISO		☑	Not aware of any
Central Maine Power		☑	
CPS Energy		☑	
Duke Energy		☑	
FirstEnergy		☑	
FPL		☑	
FRCC		☑	
Georgia Transm.		☑	
HQTE		☑	
IESO		☑	
ITC		☑	
Manitoba Hydro		☑	
MISO		☑	
MRO		☑	

Q42			
Commenter	**Yes**	**No**	**Comment**
National Grid		☑	
New England ISO		☑	
New York ISO		☑	
NU		☑	
NPCC RCS		☑	
Nstar		☑	
PJM		☑	
Progress–Carolinas		☑	
Progress–Florida		☑	
SERC EC DRS		☑	
SERC RRS OPS		☑	Not currently aware of any.
SCE&G		☑	
Southern Transm.		☑	
Tenaska		☑	
United Illuminating		☑	
Santee Cooper		☑	The proposed standard as well as the existing standards, makes no distinction between firm (network resource) and non-firm (energy only) generation. The standards should clearly state that the standard does not apply to non-firm generation.
WPS		☑	
Response: Thank You. The SDT is not aware that the proposed requirements conflict with the tariff provisions of firm versus non-firm Transmission and no specific conflict was provided in the comments.			
WECC BPA TSGT TEP	☑		1) FERC Order 693, Paragraph 1825 regarding TPL-003, Category C – The Commission directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption" rather than eliminate its applicability to this performance requirement. 2) FAC-010-1, R2.3 – "…planned or controlled interruption…" This conflicts with "No" for non-consequential load loss allowed in draft TPL.
Response: The SDT believes the draft standard does not conflict with FERC Order 693. Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. The SDT has modified the standard for consistency with FAC-010-1, R2.3. Alternatively, to the extent a conflict still exists, FAC-010-1 would need to be revised to comply with the FERC Order.			
CenterPoint	☑		FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for

Q42			
Commenter	**Yes**	**No**	**Comment**
			adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard goes far beyond the legislative intent of mandatory reliability standards and will result in construction of transmission capacity in order to remain compliant.
Dominion	☑		Current planning criteria are approved by State commissions. It is unlikely that the commissions would agree that rate payers should incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified.
Response: The SDT's understanding is that the ERO believes it has the authority to set performance requirements for reliability.			
KCPL	☑		In the past, Missouri Public Service Commission Staff have required KCPL to demonstrate that generators have "firm" transmission outlet capacity.
Response: The SDT does not believe that the proposed requirements conflict with the stated MO PSC requirement.			
NCEMC	☑		Modeling data requirements in R1 applicable to many entities may be either redundant with the MOD submittals or may be conflict for entities that are required to submit this data to Transmission Providers to comply with deadlines in their Tarffs. In addition, data submitted by entities named may be confidential so this issue will have to be addressed among those submitting and receiving needed data.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT agrees that there may be situations where confidentiality issues will have to be addressed. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12.** Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.			

Q42			
Commenter	**Yes**	**No**	**Comment**
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information. **R14.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.			
Northwestern Energy	☑		Eliminating the N-1 RAS in the West could cause problems for utilities in the West with local jurisdictional cost recovery.
Response: The standard has been modified with respect to the issue of application of RAS/SPS that should reduce the stated level of concern and remove any conflict. **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met**:**			
ATC	☑		
ISO/RTO	☑		
Response: The SDT believes the referenced requirement is necessary to ensure an appropriate balance between reliability requirements and right-of-way considerations.			

43) Q43. Do you have any other questions or concerns with the proposed standard that have not been addressed? If yes, please explain.

Summary Response: Several of the commenters reinforced or embellished the comments they submitted in prior questions. Although the SDT has provided responses to all comments submitted as part of this question, more detailed responses and summaries are provided in the prior questions.

However, several comments were received that were different from other prior comments. The SDT has made many changes to requirements based on comments submitted just for Question #43. Some of the major changes are:

1. Created a new requirement concerning short circuit analysis
2. Created a requirement to document proxies for instability, cascading outages and uncontrolled islanding
3. Changed requirements to clarify the actions allowed to prepare for the next Contingency
4. Changed requirements to clarify that Facility Ratings may be different for, and a function of, different durations
5. Added a definition for Bus-tie Breaker.

Other less significant changes were made by the SDT based on the remaining few comments. These are detailed in the responses to the individual comments below.

The following requirements were changed as a result of industry comments:

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

R1. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources.

R2.1. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6:

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.3. The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past studies.

R2.4 The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:

R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~

R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

R2.7 - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities.

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~ if the following conditions are met:

R3.5.1. All Facilities shall be operating within their Facility Ratings.

R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.

R3.5.3. A sustainable, stable, operating condition is maintained.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention.

R5.5.2 Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.

R5.5.3. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:

R6. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

Q43			
Commenter	**Yes**	**No**	**Comment**
ABB	☑		1. In Table 2 P3, more clarification is needed for "above 300 kV". For generators, does that mean those whose POI is >300kV? For transformers, is it the secondary voltage? Also, is the footnote referencing correct? "A transformer with low side rating above 300 kV" is confusing for transformers with 3 windings. What's the low-side rating of a 500/345/13.8 kV transformer? You should say "a secondary voltage rating above 300 kV" and define "secondary voltage rating" as the second highest voltage rating. This is standard nomenclature. Also, I assume you know that there aren't very many of these. The possibilities are 765/500, 500/345, and 765/345. The first two are uncommon, and the 3rd is only common in AEP and HQ. 2. In P3, does the 300 kV limit apply to the transmission circuits as well? It is hard to tell. 3. In R1, you say "Each … shall each …" Delete the second "each", which is redundant. Also delete "required for system performance studies". These words are not part of the requirement. They are part of the justification for the requirement. 4. Table 1, Extreme Event Descriptions, 3d and 3f are almost identical. 5. Table 1, P9-1, rewrite as "… (excluding circuits that share common structures for one mile or less)". P9-1 uses "structure" whereas Extreme 2a uses "tower". Make consistent. 6. P9-2 monopolar is already covered under P4-2. 7. For all of the multiple contingencies with System Adjustment in the middle, group them together something like this (for those with the same requirements): "Outage of any one of the following: 1.

Q43			
Commenter	**Yes**	**No**	**Comment**
			2. 3. 4. followed by System Adjustments followed by outage of any one of the following: a. b. c. d." This is easier to understand than separately writing each possible combination of 2. 8. Overall, the structures of the Tables needs to be made clearer and more consistent. But the ideas are good. 9. The transition is going to be critical for some of the standards that may require significantly more study work and significant capital investments in transmission infrastructure.

Response: 1. The SDT has added a footnote reference to the BES Elements Out of Service column to provide clarity on this issue. The note excludes tertiary windings.
2. The 300 kV threshold also applies to transmission circuits. The SDT has added greater detail to Tables 1 & 2.
3. The SDT has modified Requirement R1 (first draft) as Requirements R9 – R14 and the comment is addressed in the re-write.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

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<tr><th colspan="4">Q43</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information.

R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information.

4. The Extreme Event descriptions have been revised in Tables 1 and 2 to clear up this wording.
5. P9-1 (P7-1 in second draft) is intended to include all structures in a tower line. Extreme Event 2a refers to a tower line. So they are consistent.
6. The SDT has revised Tables 1 and 2 so that this only shows up in one place now, P7.
7. The SDT has revised the tables as requested.
8. The SDT has revised Tables 1 and 2 as requested.
9 - This will be addressed later in the Implementation Plan.
</td></tr>
<tr><td>AECC</td><td>☑</td><td></td><td>I am not sure what is meant by “not the least common denominator” in the background section. One long time goal of NERC has been to raise the bar and not settle for the status quo which I support. If by this phrase the drafting team is looking to minimize loopholes, remove waffle factor, and eliminate some of the innovative interpretations of requirements then I am in agreement. However, if the drafting team is thinking that the least common denominator is a level of system study that should be performed and that studies should only be performed at some higher level then I disagree and consider this attitude as contradictory to the long term goal of raising the bar. If NERC is serious about reliability then we must get this standard right. Planning is where reliability starts. If reliability is not planned for adequately and built into the system it can not be expected that the future holds much promise for a reliable system. Reliability will not happen on its own. Industry best practices should take precedence over attempts to water down the standards in order to maintain status quo.

Do any of the requirements under R1 conflict or repeat any of the requirements set for in any of the other NERC standards, especially some of the MOD and FAC standards? if so R1 should be modified, sections deleted, or reference the appropriate standard.

I would like to thank the drafting team for taking on such a formitable task.</td></tr>
<tr><td colspan="4">**Response:** The SDT felt that none of the current requirements should be weakened. The SDT felt that it is necessary to develop more stringent requirements where appropriate but not be limited by the fact that companies may need to reinforce their Systems to meet the new requirements.</td></tr>
</table>

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Commenter	**Yes**	**No**	**Comment**
The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
Ameren	☑		1. Much of the language under R1 appears to be redundant with model data requirements as listed in Reliability Standard MOD-010 and MOD-011. Such information would typically be used to produce an annual series of powerflow cases. Instead of supplying such information in a piecemeal manner to the Planning Coordinator as a separate annual effort, the Planning Coordinator should make use of the most recent set of powerflow models. This requirement, as written, could cause a needless duplication of work effort. 2. It is not clear what is meant by 'stressed System conditions' in Requirement R1.2. Does this mean higher than predicted load, lower than expected reactive resources, or other meaning? It is also not clear what is covered by 'load models' in the same requirement. 3. It is not clear how expected transfers are to be modified in Requirement R2.1.3.2. Possibilities include higher or lower in the same transfer direction, turn transfer directions around so that importers become exporters, the inclusion of non-firm transfers that can be cut, or change import/export directions. There should be some basis for the sensitivity change. 4. It is not clear how planned transmission outages are to be modified in Requirement R2.1.3.7. Possibilities include modification of the outage duration, or modifications involving more or less facilities. Since outages are scheduled in the operations planning horizon, based on the best information available at the time of the outage request, it is questionable whether they should not be included in standards that apply to planning in years 1-5 or year 6-10 and beyond. 5. Requirement R2.2.1. should be deleted. Uncertainties involved with studies looking at system conditions out to ten years in the future would preclude the need to extend a Planning Assessment beyond the ten year period. Any corrective actions needed to resolve problems found during study of long-term system conditions could be noted in the Planning Assessment without the need to extend beyond ten years. 6. In Requirement R2.3, the scope of the study work involving the short circuit portion of the Planning Assessment is not clear. It is not clear whether the study work should be based on three-phase faults only, three-phase and single-phase faults, or whether classical representation or more a more detailed representation should be utilized. 7. We assume that Requirement R2.4.3.5 would require only known generation additions,

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Commenter	**Yes**	**No**	**Comment**
			retirements, or other dispatch scenarios, and that those performing the planning scenarios would not speculate on unkown generation additions and retirements. 8. A market structure change in Requirement R2.6.1 would not constitute a material change in an area with an abundance of low cost base load generation that was always on before the market change and would still be on after the market change. 9. Under Requirement R2.6.3., Plant and System Stability analyses are considered valid until material changes in the System invalidate previous study work. Here, material changes in the system include addition of a transmission line or generator. Addition of a transmission line or generator would only have an impact on stability of generators near the new facility installation. This is not clear from the wording of the standard, which would appear to require restudy of all generators if a transmission line or generator is added anywhere on the system. 10. What would be the duration of interim operating procedures in Requirement R2.7? 11. Requirement R.2.7.1.1. states that a project initiation date should be included in the Corrective Action Plan for each project, as well as an in-service date. A project initiation date may be of use to the particular project design engineering staff, but is of little use in planning the system. Keep in mind that this is a Planning Assessment and not a data request. 12. The wording of Requirements R3.2 and R4.2 appear to require taking all transmission elements as contingencies, plus modeling contingencies which would remove all elements automatically via System protection equipment. Based on comments from the SDT, the inclusion of all single elements in the set of contingencies to be considered is not intended as part of these requirements. Please verify this in writing. 13. The wording of Requirement R3.2.1., dealing with generator minimum voltage limitations, is vague with respect to what is required. It is not clear who would determine the minimum steady-state voltage limitations for all generators, and for what conditions. Note that it may be difficult to obtain some information from IPP generating facilities. 14. Requirement R3.2.2. appears redundant with requirement R1.2.1 of FAC-008-1, which deals with Facility Ratings. Relay load limits are one component already considered in establishing facility ratings. 15. Requirement R3.3.2.1., which deals with the amount and duration of Consequential Load loss, cannot be addressed adequately. Because an outage might be caused by a transitory event with

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Commenter	**Yes**	**No**	**Comment**
			quick restoration of the outaged facility, or be caused by extensive damage requiring lengthy repairs, there would be no single value for expected duration for any given outage event in the planning horizon. Therefore, this requirement should be removed from TPL-001-1. 16. Requirement R3.3.2.2, describing permissible actions following single contingency events to meet performance requrirements, should be removed from TPL-001-1. System adjustments following single contingencies should not be permitted to meet system performance requirements. For similar reasons, Requirement R3.5, describing generator adjustments permissible as responses to single and multiple contingencies, should be modified to remove the reference to single contingencies. 17. What additional single contingencies would there be that should be considered in Requirement R3.3.3? 18. Consequential generation loss needs to be considered in Requirement R3.6 for those generators directly connected (through transformation) to transmission lines. 19. Interconnection requirements establish that generators must have low-voltage ride through capability. It is not clear how is the transmission planner performing the studies would be able to consider this capability in Requirement R4.3. 20. In Requirement R6, there is no longer a requirement to send the Planning Assessment and Corrective Plan to the regional entities, but to the Reliability Coordinators instead. Why has this change been made? RTOs should not be involved in assessing compliance. 21. In reference to Table 1, bullet point #3, it is not clear how voltage instability, cascading outages, or uncontrolled islanding would be determined under steady state conditions. 22. Under Table 1, P1, cutting of firm transfers is not permitted as a response to a single contingency. However, it is not clear whether, in preparation for a subsequent contingency, reduction in firm transfers would be permitted. Reduction in firm transfers should be permissible in this instance. 23. In Table 1, for contingency categories P5 and P8, how would loss of a transmission circuit above 300 kV followed by loss of a transmission circuit below 300 kV be handled? 24. Under the Extreme Event Description section of Table 1, note that item 3e. is a duplicate of item 3c. One of these can be deleted. Also, for items 3d. and 3f. the notation regarding early shutdown of nuclear facilities for tornadoes is not realistic. The current state of the art of weather prediction

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Commenter	**Yes**	**No**	**Comment**
			does not permit adequate forecasting of tornadoes a day or more ahead of time which might be a cause for concern for a particular nuclear facility. 25. With respect to Table 2, contingency types P5 and P8, it would seem that events should include the same items as shown for contingency type P4. 26. In Table 2, for contingency types P1, P3, P4, P5, P8, and P9, clarification is needed as to whether distribution transformers (138-69 kV or 138-34.5 kV, for example) would be included in the events, or whether the transformers mentioned would be restricted to transmission transformers. 27. For the various stability scenarios, note that Consequential Load Loss would be a function of how System protection equipment is set up for particular scenarios. Delayed clearing time/Zone 2 clearing times could result in load dropped that would not have been dropped for events cleared in primary clearing time. 28. In Table 2, Note 1 ii., is it the intent of the drafting team to require dynamic model representation of relaying equipment? General comments: 29. We are not sure that a wholesale replacement of the existing standards TPL-001-0 through TPL-004-0 is required. We agree that additional clarification is needed for some items, and particularly for the study assumptions that go into the development of models to be used for the performance testing, but we do not agree that the proposed replacement standard provides that necessary clarification. Further, we believe that the replacement standard relies too much on the accompanying tables. More text needs to be included in the standard regarding the system performance requirements. 30. There is a lot of subjectivity involved in developing the study assumptions that need to be considered in the sensitivity models for study. How can we be sure that one or more of the sensitivity requirements in R2.1.3 stated for consideration are of the same level of importance by both auditors and those performing the studies? We are interested to see what the measures for all the requirements of the standard will be when they are developed. 31. Additional planning standard requirements for the EHV system to meet all N-2 conditions without dropping some load will require significant material changes, where feasible. We do not believe that the significant additional costs required for compliance would produce tangible benefits and a corresponding significant improvement in system reliability. What is the justification for the separate

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Commenter	**Yes**	**No**	**Comment**
			treatment for the EHV (>300 kV) facilities? One obvious effect of such requirements is to create a bias against any straight bus configuration for facilities above 300 kV. As stated in response to Question 25, there are existing facilities which cannot be converted from their present configuration. For those facilities which could be upgraded, an implementation period of several years would be needed to meet such requirements. 32. Meeting the requirements of this standard should not be a full time job. There are many more planning activities that need to be performed other than simulation testing to demonstrate compliance. The existing TPL standards require a significant manpower effort to perform the required studies and develop the planning assessment and corrective action plan. We are concerned that the replacement standard, as proposed, will create an even greater burden on the transmission owners without a commensurate benefit to the system reliability. 33. It is not within NERC's or ERO's scope of responsibility to address load loss. The focus of the standard should be on the system capabilities and not how much local load is dropped for a substation outage in a defined service area. A few reports showing the resultant bus voltages and facility loadings on a percentage basis for all single and a the more severe multiple contingency events, including operator or automatic mitigation procedures, should be adequate to demonstrate compliance.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms “stressed System conditions” and “load models” have been removed.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information**.**

3. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity’s decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

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Commenter	**Yes**	**No**	**Comment**

4. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document if there are any "planned" outages such as a multi-year Transmission right-of-way rebuilds where outage durations may vary. It is the entity's responsibility to determene the actions necessary to handle extended outages and which are more significant to study System responses.

5. The SDT felt that this wording was appropriate based on comments by FERC in their orders concerning long lead time projects.

6. R2.3 - The studies should be based on the individual TO's practices which are assumed to be in agreement with good utility practice. An annual assessment of the results of these studies is required.

7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study System responses.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

8. The SDT removed market changes from the requirement (see Requirement R2.6.2)

R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

9. The SDT added wording to Requirement R2.6.2 to clarify this concern.

10. The "interim Operating Procedure" was deleted in response to Industry requests for more clarification as being an unnecessary modification of the more general term "Operating Procedure" that is already a defined term in the NERC Glossary.

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Commenter	**Yes**	**No**	**Comment**

11. Requirement R8 (old Requirement R6)which focuses on the distribution of the Planning Assessment results to affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

12. In Requirement R3.2 and Requirement R4.2, the SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. For example, Requirement R3.2 would require modeling breaker-to-breaker outages rather than modeling bus-to-bus outages in a study.

13. Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

14. R3.2.2 - While FAC-008-1 generally addresses this issue, the SDT felt that the relay loadability issue needed to be specifically addressed to ensure its impact was not inadvertently ommitted from Contingency analysis.

15. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.

16. R3.3.2.2 has been changed to clarify the concern.

R3.3.2.2 – Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

17. The requirement refers to everything over and above single Contingencies.

18. Requirement R3.6 was completely re-written in Requirement R3.5.

R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

19. The SDT feels that planning studies should be of sufficient scope to cover this situation.

20. R6 (first draft) - does not specify any action by the Reliability Coordinator - the Planning Coordinator coordinates distribution. This action

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Commenter	Yes	No	Comment

does not involve assessing compliance but involves peer review and coordination of analysis.

21. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology.
Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities Load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies.

22. The SDT has replaced the term "firm transfer" with "firm transmission service" in Tables 1 and 2.

23. Loss of a Transmission circuit above 300 kV followed by loss of a Transmission circuit below 300 kV would be treated the same as loss of Facilities below 300 kV.

24. The SDT has revised Tables 1 and 2. Items 3d and 3f are meant to capture shutting down of a nuclear power plant as a result, not in anticipation, of events such as tornadoes.

25. Table 2 has been revised so that the elements are now the same.

26. See footnote 2 and 3 in Table 2 for clarification.

27. The SDT agrees. The Load lost as a result of the event specified can be different for different Contingency scenarios (i.e., normal versus delayed clearing).

28. This should already be in your models.

29. TPL-001-1 is based on the existing TPL standards and is not a wholesale replacement but an aggregate of TPL-001 through -004, but does contain new elements and clarifying language. FERC Order 693 asked the SDT to consider combining the 4 standards. Please provide any comments on specific elements needing additional clarification in future responses in the standard development process.

30. Measures will be added later in the process.

31. The SDT felt that it was appropriate to raise the bar on situations that would impact the reliability and performance of the System and considered above 300 kV as the backbone of the System and thus needs to be extremely reliable and was an appropriate place for raising of the bar. Implementation Plan will be supplied with a later draft.

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Commenter	**Yes**	**No**	**Comment**
32. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 33. FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.			
Brazos Electric	☑		1. In R1.1.1. it appears the data that is being requested requires some amount of survey to determine the mix. This data would require a great deal of manpower and provide little more benefit than simply varying the data for comparison. However it does say in R1 upon request so does this allow the Planning Coordinator the descretion as needed on this type data? 2. R1.2, What is 'supporting rationale' and 'validated' mean? What are "stressed" System conditions? It appears (from 2.1.3) that stressed means various sensitivities. 3. R1.4, define 'long-term', generation outages are considered confidential information in ERCOT and thus are not available to all TOs, see next comment 4. R1.5 somewhere (perhaps in R1) the language should include "its respective portions of the data" or something to that effect meaning that a TO should not be held accountable for a GOs data. R1 appears to read that each entity shall provide the requested data. This seems to be intuitive BUT there are GOs that feel the data responsibility for the entire system belongs to the TOs and this leads to delays in getting accurate information if its uncertain as to who provides what data. 5. In R2 the language indicates the TP and PC shall each perform studies. There should be some clarity here. Also, it indicates that each shall assess "its portion of the BES". This needs to be clarified as well, obviously contingencies on other portions of the BES may cause issues within different portions. again, what constitutes documentation? 6. R2.1 it appears from the wording (shall "address" all five years) that the planning assessment must be done on all five years but 2.1.1 appears to state only 2 years are required. Please clarify. 7. R2.1.3 this seems to indicate that the studies mentioned in 2.1.1 and 2.1.2 should be "stressed" by the conditions listed below or just by one of them. We assume this means using only one is acceptable with proper documentation. Is that correct? Further, the sensitivities are ambiguous. How does one justify higher load levels or even know what they are without input from other TOs or the PC? How does one even guess at the other variables? what is meant by 'long lead time facility'? IF this only means for a TOs "portion of the BES" then it makes more sense but are these even valuable considering the wide range of data. The only variable that can be adjusted with any accuracy is the generation and ERCOT maintains the confidential data in this area. We assume R2.1 to mean you

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Commenter	Yes	No	Comment
			need to assess two peak summer cases, one off peak and then look at varying generation patterns on those cases. This appears to be the latitude given. Is this correct? 8. R2.2.1 are generation additions considered a "project"? If this means that a case must be created and assessed by all TOs for a known generation addition that is 12 years out, then this will lead to unnecessary studies. We assume this to mean, in the case of a generation addition, that the connecting TO should make an assessment once the PC considers this new addition to be valid for study. Is that correct? 9. R2.3 what is meant by "past studies" and how long must these be kept? Or is this at the TOs discretion? 10. R2.3.1 how does one know if the changes will result in increased fault currents until studies are done? This implies that studies SHALL be done for just about ANY change to the BES. There must be discretion allowed here. The word "shall" does not afford any discretion. 11. R2.4 the same comments for R2.1. apply here concerning years of study and defining 'stressed'. Additionally this type study seems to provide better results when done for the BES which would require input from all TOs thus a study based only on "its portion of the BES" would not have as much value unless you are referring to generation additions and localized studies. 12. R2.5.1 does not allow any discretion, for any and all all modifications, additions, etc…a study shall be performed. This is not needed in all cases. 13. R2.5.2 Wording such as "material changes" and "vicinity" are ambiguous terms without discretion being allowed the planner. Voltage level Line changes, amount of generation, something needs to be added to clarify. 14. R2.6.1 again, what are material changes? Topology changes and generation changes happen monthly, weekly. Are studies to be invalidated for each 'material change'? 15. R2.6.3 who determines if the study is no longer valid? The TO, PC or the agreement of both? 16. R2.7.1 what is a 'project initiation date' and why is this needed? 17. R2.7.2 Projects are added to cases after an analysis has been performed to see if the project is an acceptable alternative. In that analysis the project is 'retested' to see if it is effective. This is assume to be acceptable for the definition of 'retesting'.

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Commenter	**Yes**	**No**	**Comment**
			18. R2.7.3 unsure what 'committed' means regarding projects nor understand the need to have this documented anywhere. 19. R3.2.2 what is 'relay loadability' and where would you note how it is supposed to be treated? 20. R3.3.1 how is this different than R3.1? 21. R3.3.2.1 why is there a need to know how much non-consequential load loss exists for each contingency and how can one predict the length of time this will last? 22. R3.3.2.2 Do we need to document the 'system adjustment' for each contingency? 23. R3.3.3 what is a severe impact and what is one that is less severe? 24. R3.4 what is the difference to 3.3.3? The definition given in the NERC Glossary from May of 2007 of Cascading Outage is still vague, it appears to allow the TP or PC the discretion to determine it based on studies. Is this the intent? 25. R3.5 what is the time limit for run-back? 26. R4.4 how can TPs identify what generation upgrades are needed (protection and control modifications)? 27. R4.5.2 whats the difference between this and 4.5.1? 28. R4.6 the generation levels could be too low for the studies to be useful, perhaps voltage levels should also be added or allow for TP/PC discretion. 29. R4.6.3 seems to allow some TP discretion in deciding which planning events are more severe but how does one know that without studies? 30. R5 this seems to have no direction for either party. 31. R6 is ambiguous Table 1 32. terms such as voltage instability, cascading outage and uncontrolled islanding should be defined

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Commenter	**Yes**	**No**	**Comment**
			or allowed to be defined by the PC. If consequential load loss is allowed for all cases then why even mention it? Isn't this like saying if the line trips, it will be out of service? why would one want to document this amount, perhaps for some sort of ranking? Planning events 33. what is a 'system adjustment'? if this means to manually redispatch the BES for each condition then these studies shown under P4 will take so long to complete that they will be invalid by the time they are done. In ERCOT, the economics of redispatch are not known to the TP thus this is done by the PC. an automatic computer simulated redispatch will possibly not have the same results. Define 'generator' for is this a single unit, the whole train, the largest unit or other? 34. For P6 events and above, if consequential load loss and non consequential are allowed, they why study these events? Do TPs plan and build transmission to eliminate the overloads for these events or just study them so that the results are known? Studying every possible event or combination does not make the studies better or provide a higher insight to areas of concern. A number of the combinations have a low probability of occuring and performing the studies and analizing the results will be a manpower burden and provide no better clarity on needs of the system. Table 2 35. The number of events to consider seems excessive although this is not our area of expertise. If each of these is to be run for each 'material change' in the BES then this list is excessive without more leeway or guidance provided.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to appropriately reflect the behavior of the System.

2. The SDT agrees with your concerns and has revised this requirement (now Requirement R9). The terms "stressed System conditions", "validated", and "supporting rationale" have been removed.

3. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. Further, it is not the intent of the standard to require consideration of confidential information that is not available.

4. The standard has been revised to identify specific entities responsible for providing the required information.
5. The extent of coordination between the TP and PC can vary depending on many factors such as whether you are part of an ISO/RTO, vertically integrated Investor Owned Utility, or Transmission only company. The Functional Model envisions that planning entities will not only need to use overlapping models to simulate how the System will respond to Contingencies, but they will also be layered to provide for more locally focused studies as well as more global studies. Planning Coordinators need input from the planners doing the local studies to complete their overall studies. Planners need to coordinate their activities and sort out which entity will be detailing its studies to what extent. Documentation of entity studies needs to demonstrate that the System response to Contingencies and any Corrective Action Plan has been screened so as to meet the performance requirements stated in the standard, such as not exceeding applicable voltages and ratings.

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Commenter	**Yes**	**No**	**Comment**

6. Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements. Requirement R2.1.1 is in reference to Requirement R2.1 which states that the Planning Assessment "be supported at a minimum by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6:" To further clarify, the SDT has deleted the "all five years" language.

7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstiviyies are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

8. Known generation additions are considered a project and must be studied if the lead times are longer than 10 years.

9. R2.3 - See Requirement R.2.6.2 where this is defined.

10. The SDT has revised the wording of R2.3 to try to clarify that short circuit analysis must be conducted annually but that past studies as defined in Requirement R2.6.2 may be used as appropriate.

R2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually and supported by current or past s

11. Requirement R2.4 has been re-worded to clarify this situation.

R2.4 The ~~System Stability portion of the~~ Near-Term Transmission Planning Horizon portion of the Stability analysis ~~Planning Assessment~~ shall be assessed annually ~~address all five years of the assessment period,~~ and be supported by current or past studies. The following studies are required ~~annually~~:

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Commenter	**Yes**	**No**	**Comment**

12. See Requirement R5.6.2 which provides the bounds you are looking for.

13. and 14. This wording is intentional to allow the planner some discretion.

15. The SDT has revised Requirement R2.6.3 as the new requirement R2.6.2 to clarify this concern.

R2.6.2 For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

16. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

17. The specific requirement to perform re-test has been removed. The purpose of the Corrective Action Plan is to list the actions that are needed to meet performance requirements. The studies, current and/or past as appropriate as well as the extent of the size of the study area, are performed to support compliance and demonstrate that the requirements are met.

18. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

19. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuits thermal or Stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements.

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Commenter	Yes	No	Comment

20. Requirement R3.1 requires studies to be performed. Requirement R3.3.1 requires that the results meet the requirements of the standard.

21. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.

22. Yes.

23. The intent is to allow the Transmission Planner flexibility for deciding which multiple Contingency Planning Events are run during its annual studies. The standard leaves the classification of "severity" to the engineering judgement of the Transmission Planner based on experience of the System, past study results, input from operations staff, etc. The Transmission Planner will need to explain why others would be known to be less severe. For example a N-1-1 involving two non-related and distant Facilities could be excluded by the TP if desired.

24. Requirement R3.4 covers Extreme Events, Requirement R3.3.3 covers Planning Events. The SDT did not propose a new definition for cascading outage or cascading.

25. The use of the defined term 'Facility Ratings' dictates the time limit.

26. The outcome of the assessment should identify the actions required.

27. In new Requirement R5.5.2, clarification has been provided to differentiate the events.

R5.5.2. Performance shall meet the requirements for Planning Events in Table 2 – Stability Performance.

28. Those values are based on Large Generator Interconnection Procedures as approved by FERC.

29. It does allow some discretion but good engineering judgement is assumed and you must document your rationale.

30. This requirement assumes that the two parties will react in a professional manner to resolve any differences.

31. The new Requirement R8 clarifies this.

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

32. In general, new definitions are proposed along with the proposed standard, and will be included in the Glossary of Terms upon approval of

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Commenter	Yes	No	Comment
the standard. Definitions for Cascading and Stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions for voltage instability. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 33. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 34. For P6 and more severe Events, loss of Consequential and Non-Consequential Load is allowed. The events will still need to be studied to ensure that System reliability and security is maintained and that any outage would not result in unacceptable System performance, such as, cascading, instability and uncontrolled separation. 35. The SDT understands the potential work load increases. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
City Water Power and Light	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. The SDY should remove all Requirements that are subjective and can't be measured. The assumptions the Transmission Planners and Planning Coordinators use to conduct the studies should be posted.
Response: The SDT has endeavored to draft Requirements that are objective and measurable. Since this comment did not include specific Requirements that the commenter proposes should be deleted, the comment relating to removal of subjective, unmeasurable Requirements is unactionable. The SDT believes the comment relating to posting assumptions implies that the standard should not have study assumption Requirements but should only require that assumptions be posted. The SDT is unclear where assumptions would be "posted" but in any event if study assumption Requirements were removed, then the SDT believes there would be little or no value in having study assumptions "posted".			
Dominion	☑		GENERAL COMMENTS: (1) Making the standards more stringent by "raising the bar" is not going to result in a dramatic improvement in system reliability. Even the best designed systems are susceptible to human error. Dominion has at least 5 years of transmission outage data clearly illustrating that any resulting loss of load (both consequential and non-consequential) has had an average duration of only 4-7 customer-minutes per year. Going forward, the emphasis and focus should be on planning and

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Commenter	**Yes**	**No**	**Comment**
			operating the bulk electric system so as to confine any transmission outages to the immediate, local area, and not allow the cascading of outages beyond control area boundaries. (2) Although we are unable to put specific numbers on the impact of "raising the bar "with respect to non-consequential load loss, it will be enormous. Increased staffing levels may be required, and we would likely incur significant increased transmission maintenance and construction costs. It is likely that State commissions everywhere (not just Virginia) would agree that rate payers should not incur the significant cost increases required to meet more stringent planning criteria (i.e. - "raising the bar") when the corresponding improvements in transmission system reliability cannot be quantified. SPECIFIC COMMENTS PERTAINING TO REFERENCED SECTIONS OF THE STANDARD: (1) The last block in Category C of Table 1 of the existing standards deals with protection system failure. We interpreted this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure resulting in a second-zone trip of the faulted line (even though only one element will be lost). The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect. The proposed Table 2 of TPL-001-1 is silent about this. Is there a reason why this requirement was left out? (2) The requirement R4.6.2 may cause some confusion due to the last part "….whichever is greater". It is suggested that the entire wording for this requirement be replaced as listed below to avoid any misunderstanding. "Shall be performed for changes in the real power output of a generating unit if either of the following applies: (a) the increase is more than 10 % of the existing capacity (regardless of the amount of MW increase) (b) the increase is more than 20 MW (regardless of the % increase). Something to think about regarding a cut-off limit of 10% or 20 MW: We had a unit with 800 MW existing capacity and the request was to increase it by 15 MW making the total new capacity of 815 MW. The requested increase was less than 10% of the existing capacity and also less than 20 MW, meaning the plant stability study is not required. However, we found that the increase of 15 MW made the plant unstable and we had to come up with a solution (and we did). This example warrants to include something like…. "However, in cases where a stability margin is known (or estimated) to be slim, stability study should be performed regardless of the % or MW

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Commenter	**Yes**	**No**	**Comment**
			amount of increase (this leads to defining "Stability Margin"). (3) Table I, bullet 3 states that "Voltage Instability, cascading outages and uncontrolled islanding shall not occur." There is no definition for "voltage instability" anywhere in the proposed standard. (4) R.3.3.2.1. states "Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment." This requirement creates significant unnecessary work without adding any value to system reliability. (5) Extreme Event Description 3.d. states: "Shutdown of a nuclear power plant(s) and other facilities a day or more prior to a hurricane, tornado or wildfire, or for other common causes." It would appear that day ahead planning for a tornado is not possible, or applicable, for inclusion in this listing.
Response: Specific 1. The SDT agrees with your concern and is working on a solution for a future draft. 2. The wording was lifted from FERC and has not been changed. 3. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, "Definition and Classification of Power System Stability", IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. 4. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-consequential) and duration should be based on best judgment for the common cause of the event. 5. Extreme Events notes have been changed to address this concern.			
E ON US	☑		1. R1.4 "including protective relays with consideration given to spare equipment strategy" I do not understand the intent of this phrase or what it adds to the requirement. 2. R2.6.1 "and market structure changes" What is this, does it require a definition? 3. R2.7.1.1 What is the project initiation date; the date approval is sought, received, materials are ordered, construction begins? Many projects are upgrades or replacements that this will be meaningless. Don't you really only want multiyear projects? 4. R2.7.2 The initial study process will incorporate testing. This will require the creation of additional cases and additonal testing prior to the Planning Assessment submittal. Most projects should be identified during the Long Range time frame. Inclusion of the project in the next years base cases and subsequent testing should be adequate. 5. R2.7.3 Define a "Committed Project". MISO has spent years on this. 6. R2.7.4 Changes in timing of all projects should be documented in the Planning Assessment. Why would you document Committed Projects that are removed but not any delays or accelerations?

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Commenter	**Yes**	**No**	**Comment**
			7. R3 Sensitivity studies (if retained) should have less stringent performance requirements than the other cases required by R2.1. 8. R3.3.2.1 Unless this is limited to above 300 kV, many hours will be spent for naught. The lower voltage systems often have tapped loads that will trip with the line. The time required to restore will vary on the fault location, and time for switching, sometimes remote and sometimes manual. I do not see the need for or the benefit of this requirement. Please explain. 9. P3 Event is poorly worded, see response to Q25. 10. P6.1 above 300 kV, below 300 kV or all? The tables need to be reviewed to make sure that the voltage applicability is clearly stated. 11. P9.6 Why is this a requirement? It should be much less severe than any of the prior requirements. 12. Extreme Event 9 (3ph fault with loss of all generating units at a station) is in conflict with Q33 which says it was not included). Am I missing something? 13. Other, it appears that we are not required to study the outage of a transmission line or transformer followed by the outage of a generator. Was this overlooked, or did I miss it? Would system adjustment be allowed?
Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. 2. R2.6.1 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant. 3. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time 4. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".			

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Commenter	**Yes**	**No**	**Comment**
R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 5. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 7. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study system responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: 8. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 9. Please see response to comments on Q25. 10. The SDT has revised Tables 1 and 2 to provide more clarity. 11. P9.6 was to address FERC directive in Order 693 to consider spare equipment strategy. The SDT has revised Tables 1 and 2 to remove P9.6 and included this consideration in R11 of the second draft of the standard to address this issue. 12. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included in the Extreme Events in Table 2 (on Stability Studies). 13. Tables 1 and 2 have been revised to address your comments. P3 is meant to cover the combination of overlapping outages regardless of the sequence in which the outages occur.			
ERCOT ISO	☑		1. R1.1.1 - Are percentage of load that is industrial, commercial, and residential needed? 2. R1.2 - The wording is confusing. If the power factor is based on historical measured values, does it have to be during contingency (stressed)? 3. R1.5 - "Planned Facilities defined in accordance with the documented criteria of the Planning Coordinator" - what is meant by this?

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Commenter	**Yes**	**No**	**Comment**
			4. R2.1.1, R2.1.2, R2.1.3.1 - are all studies to be run using all the contingencies defined in Table 1 - Steady State Performance? 5. R2.6.1, R2.6.2, R2.6.3 - past studies will never be able to be used if the addition of a transmission line makes them invalid! 6. R3.2.1 - What is meant by "minimum steady state voltage limitations of all generators"? 7. R3.2.2 - Relay "loadability"?? What is meant by this? Sounds unreasonable for steady state studies as facility rating should reflect limitations of relay equipments such as CT"s. 8. General comment: If this proposed standard is approved, since it contains requirements that are more restrictive than current standards, there will need to be a transition period to allow transmission to be built to allow systems to meet the new requirements.

Response: 1. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System.
2**.** The SDT has revised this requirement based on industry comments to clarify intent.
3. The referenced verbiage has been deleted from the revised standard
4. Regarding Requirements R2.1.1 and R2.1.2, Requirement R2 states that the "Planning Assessment shall use current or past studies …." The Planning Assessment is to cover the five year period but the entity is only required to run a limited number of studies. It is the responsibility of the entity to determine if past studies can demonstrate that the performance requirements are met. If past studies in conjunction with the required studies do not demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
Regarding Requirement R2.1.3.1, the SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

5. R2.6.1, R2.6.2, R2.6.3 - The change must be "material" as stated in the standard meaning it must have an impact on the study results or may only make some results invalid and not relevant.
6**.** R3.2.1 - Generator high and low voltage limits are part of the constraints and are considered part of Facility Ratings in FAC-008. FAC-009 provides that the information be provided by the Generator Owner.

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Commenter	**Yes**	**No**	**Comment**
7. R3.2.2 - The SDT used the term "relay loadability" to describe the maximum Transmission line loading on a specific circuit that is permitted before line relays might see the Load current as a fault and trip the circuit. In those cases where the relay loadability limit is lower than the circuit's thermal or stability rating, the relay loadability limit should be applied as the benchmark for meeting the performance requirements. The SDT believes that equipment ratings, such as CT ratings, should also be reflected, but not necessarily as part of the "relay loadability" limit. 8. The SDT agrees and that will be addressed in the future			
AECI	☑		1. Based on the p1 to P9 events one would have to model a breaker to breaker instead of bus to bus. This would be a large undertaking and it seems that it would be more conservative to have a bus to bus model. 2. Question on P4 - does this apply to all generators on a system or is there a MW limit to the size of the generator. 3. P5 Does this mean running N-2 for the 300 KV for all seven cases that would be required. This could take a large amount of computer run time. 4. We are stating that this change to the standard is not warranted. However, if all these changes are implemented what used to take approximately 1 month to assess will now take approximately 4 months and we are not that big of a system. I assume that the time and manpower to perform all the contingencies has been considered.
Response: 1. The SDT revised the event descriptions to provide clarity on simulations in response to FERC Order 693. Depending on the configuration, modeling bus-to-bus outages in a study is not necessarily more conservative than modeling breaker-to-breaker outages. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. 2. The intent is that the standard would apply to all Facilities (including generators) that are represented in the transmission planning simulation. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. 4. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements.			
Allegheny Power	☑		General Comments: 1). We believe the 300 kV cutoff should not be used. It should be based on the definition of a Backbone Facility. The 300 kV and above standards should only apply to backbone facilities that are used to provide overall energy transfer and ties to other systems and not facilities that provide load serving purposes. Backbone facilites should be specifically defined and accepted as Backbone facilities through RTO and RE review and acceptance.

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Commenter	**Yes**	**No**	**Comment**
			2). Planning Scenarios should be forced to include a market based scenario under the Planning Authority obligation which should include long range market projections for generation dispatch, significant energy price changes due to environmental issues or fuels, and market impact of large transmission reinforcements. 3). It should be noted in the process that additional planning resource additions (maybe as much as 30%) will be required to met these new study requirements since they are much more expansive than the existing requirements. 4). These standards could require substantial (millions) upgrades to the system to meet the proposed changes. These are primarily due to the 300 kV and above standard revisions and the non-consequential load drop criteria adjustments.
Response: 1. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed that the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering Contingencies of two EHV Facilities due to one Event. Systems operated at these voltage levels generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers the energy is delivered by the other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. **2.** Marketing and economics are beyond the scope of the SDT. This is a reliability based standard. 3. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. 4. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process.			
AEP	☑		(1) Consider clarifying system performance requirements that would be applicable during (a) the first two minutes after the system disturbance when slow-acting automatic system adjustments (such as the operation of motor-operated-air-break switches that are relayed to sectionalize the faulted segment of a multi-terminal circuit; the changing of taps on tap-changing-under-load transformers; the switching of capacitor banks; etc.) would not allowed to be considered, (b) the next three minutes (two to five minutes after the system disturbance) when these slow-acting automatic system adjustments would be allowed to be considered, (c) the next twenty-five minutes (five to thirty minutes after the system disturbance) when manual system adjustments would be allowed to be considered, and (d) the time period beyond thirty minutes after the system disturbance when no system adjustments of any kind would be allowed to be considered. (2) Consider clarifying which functional entity is expected to provide what information specified in this standard, especially in requirement 1.

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Commenter	Yes	No	Comment
			(3) Consider clarifying the need for functional entities to provide competitive sensitive information such as planned outages. (4)The system stability study documentation requirements R2.4 and R4.5 do not specify a level on the scope of studies or indicate the extent of coverage across a system required for acceptability. A reasonable scope of such studies might include studies of a system nature in association with dynamic devices, or voltage collapse or cascading scenarios, but what else would be required? Or, how much more stability study documentation beyond what is necessary to comply with TPL-001 through 004 would be required? Specific comments regarding R2.4 are as follows: what does "address" all five years mean? How much of the system do you need to study (for example, do you need to apply faults at every bus)? Again, you wouldn't know how much studying needs to be done before this requirement is satisfied. In R2.4.1 and R2.4.2, depending upon the study at hand, some other load condition such as shoulder peak may be more appropriate. Why should you be required to do peak and off-peak cases in such an instance? In R2.4.3 you are forced into doing at least one of the sensitivity studies listed (i.e., "to reflect one or more of the following conditions..."). Is this intentional? Depending upon the study at hand, none of these may be worthwhile doing, and there may be some other parameter that would be better looked at for sensitivity purposes. Existing TPL-001 through 004, Table 1, Category C3 requires any combination of generator, transmission line, transformer, or HVDC pole block in succession. The new standard excludes several of these combinations from being required in P4, P5, P8 and P9. Is this an intentional exclusion? If so, why? The standard should state explicitly that existing generation does not need to be studied unless R2.5.1 or R2.5.2 apply.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. The System adjustments that can take place during various time periods are different in different systems, and should be based on agreements and coordinated among the entities performing the studies. 2. The SDT does not believe it is necessary to be so prescriptive but only requires that accurate data be provided in order to build accurate models. 3. Commercially sensitive and confidential information is covered by existing rules and regulations and can't be altered by the SDT. 4. Address means that you must cover all 5 years in the assessment. Good engineering judgement must be applied. The requirements are minimal and one can always do additional studies. Yes, this is intentional but good engineering judgement may imply that you need to do more than one sensitivity. The SDT has interpreted C3 as described in the tables. The SDT feels that the conditions are properly identified.			
APPA	☑		The Standards are a great start in getting a set of requirements in place that will provide a planning methodology that will be transparent to the Functional entities in the interconnections and will produce results that will permit reliable planning and operations of the BES. 1. Requirement 5 is a start at attempting to share the results of the planning studies with the correct entities. However, because this is such an important part of reliable planning, this requirement

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Commenter	**Yes**	**No**	**Comment**
			should be rewritten to be much more definitive and comprehensive. It is recommended the SDT review the FAC-014 Standard where this Standard deals with who is to receive the methodology for calculating SOLs. The SDT needs to insure that the Transmission Planners and Planning Coordinators share their Near-Term Planning Horizon Studies with the Transmission Operators (Operation Planners) and the appropriate Regional Entity Planning Committees and Operating Committees. 2. It is also recommended that the SDT remove all Requirements that are subjective and cannot be measured. For example, who must the Transmission Planner share information with? Requirement R5.2 states that information must be shared with Transmission Planners of neighboring impacted areas. A Compliance Monitor cannot determine if a neighbor is being impacted. In fact, from an enforcement perspective, if the involved parties must go before a Judge, who will determine if someone is impacted or not? 3. In addition, the assumptions the Transmission Planners and Planning Coordinators use to conduct the Studies are not required to be shared or posted. As an example, in some parts of the BES Transmission Planners and Planning Coordinators use Flowgate Methodology to study the BES, while others use Rated System Paths, and still others use Area Interchange (Network Methodology). 4. This standard needs to be modified to respond to several requests from Order 890 and Order 693. These Orders request that through the Standards, information be made available, posted, and shared with the appropriate reliability functions. This information includes the results of Planning Horizon Studies, Operating Horizon Studies, and eventually the determination of Available Transfer Capabilities. This information also includes, but is not necessarily limited to: how do the planners treat the "counter flows" in their studies, what are the generation and transmission planned outage schedules used in the planning studies, how are Network Loads and Network Facilities treated in planning studies; and how do the planners treat Grandfathered Transmission and Grandfathered Power and Energy Contracts in the planning studies?
Response: 1. The SDT assumes that this is actually referring to Requirement R6. This requirement has been re-written as Requirement R8 and ties back to FERC Order 890 for distribution. **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 2. The SDT has attempted to not add subjective requirements. However, as measures are developed in a subsequent release, the SDT will review all requirements for subjectivity. 3. Documentation is required in your assement to decribe that you have met the requirements. 4. Information will be shared as required in various orders and regulations as shown in the new Requirement R8 for example.			
ATC	☑		Following are additional comments on the proposed standard.

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Commenter	**Yes**	**No**	**Comment**
			1. R1 Each sub-requirement (R1.1 to R1.5) should specify which Functional Entity (of those listed in R1) is responsible for providing the modeling data. For example, while logically it appears that R1.1 is applicable to the LSE only, it may be argued that parts of it may be applicable to the Transmission Planner also. 2. R1.1.3 We do not agree with identifying the DSM load reduction "consistent with operational requirements" for the purpose of modeling Load in planning studies. This is because DSM is typically employed either for Capacity deficiencies, but not for operations needs. 3. R1.3 "Firm transfers/Interchange Schedules and….." Should say either firm transfers or interchange schedules but not both since they are not equivalent. If the intent here is to model each Balancing Authority's Firm resources and Firm "commitments" needed to supply the Firm Load, then we suggest using the term Firm Commitments defined as the Native Load plus Firm Transmission Service plus LTTRs. 4. Firm Transfer -- Either define this term or use the existing NERC Glossary term Firm Transmission Service instead. Alternatively, use the term Firm Commitments defined as the Native Load plus Firm Transmission Service and LTTRs. Further, in Table 1, the "Interruption of Firm Transfer Allowed" performance requirement should be clarified/reworded to indicate if firm transfer was intended to comprise both firm point-to-point and network transmission service. If so, then curtailment of firm point-to-point transmission service should be permitted for all events P1-P4. Alternatively, the performance requirement could be changed to "Generation Redispatch Allowed". Given the future Day 3 MISO market structure, standards that refer to Generation Redispatch must include Demand Response. 5. R1.4 We believe that each Reliability Coordinator (RC) already receives the planned outage information from all TOs and GOs and maintains it in the Outage Scheduler. Can the Planning Coordinator obtain this information from the RC's operating in its footprint? 6. R1.5 The Transmission Planner is also very likely to have a documented criteria for planned (committed? see R2.7.3) facilities, so this requirement should say TP/PC instead of only PC. What standard will require the TP to have criteria? There should be a separate requirement that applies to the Generator Owner and includes specifics, such as reporting contemplated additions, modifications, and retirements. 7. R2.1.3.1 It is not clear what additional "variability of Load/demand and Load power factors due

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Commenter	Yes	No	Comment
			to season, weather, or time of day" over and above what is modeled in the seasonal base case is expected here. For example, what additional load variability can be studied in a summer peak base case which already represents the system snapshot of a hot (weather) summer (season) mid-afternoon (time of day) loading condition? 8. R2.5.2 Please provide more examples of what would comprise "material changes" that trigger a plant stability study (besides the addition/removal of transmission line). Would it be better to say electrical proxmity (to capture the concept of electrically "close" instead of electrical vicinity? 9. R2.6.1 to R2.6.3 Should all "material changes" trigger a new study? Shouldn't a new study be done only for those changes that are expected to have an adverse impact on system performance? For example, adding a transmission line outlet at a generating station will rarely have an adverse impact on plant stability. Suggest that these requirements specify the need for a new study to support the planning assessment only when changes "that have an adverse material impact on system performance" have occured. 10. R2.7.1.1 It is unclear what is the need/benefit of including a the project initiation date; the project in-service date should be enough in a corrective action plan. Suggest deletion of project initiation date from the requirement. 11. R2.7.3 What is the difference between "committed projects" referred here versus the "planned facilities" referred to in R1.5? Please explain distinction between committed, planned and proposed projects/facilties. 12. R2.7.4 "Not remove committed projects……" Note that a committed project may not get cancelled but can very likely be deferred --- how should deferred projects be handled? 13. R.3 Per this requirement, the BES should be analyzed for normal (N-0) performance. However, Table 1 does not include the corresponding performance requirements. Further, R3.1 refers to studies for evaluating performance requirements in Table 1. Shouldn't Table 1 include normal system performance requirements? 14. System Adjustment -- What automatic/manual actions comprise this term? It will be helpful if the standard explicitly states which post-event system adjustments are acceptable/permitted to meet performance requirements for single contingency events (P1, P2 or P6) versus which pre-event system adjustments (specifically load shedding) are allowed/permitted to prepare for the next contingency (after the N-1 contingency has occurred) in multiple contingency events (P3-P5, P7-P9). This distinction does not appear to be addressed by requirement R3.3.2.2 in the draft

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Commenter	**Yes**	**No**	**Comment**
			standard. 15. R3.3.2.2 is inconsistent with the Planning Events in Table 1. While the requirement states that shedding firm load and curtailing firm transfers are not permitted for single contingencies, these are allowed for event P6 in Table 1. Further, although the requirement implies that these two types of system adjustments are permitted for multiple contingencies, at least one of them is not allowed for the multiple contingency events P3, P4 and P5 in Table 1. 16. System Adjustment Duration -- What is the allowable time for completion of system adjustment? Requirement R3.3.2.2 states that it is the time period allowed by the Transmission Owner's applicable time-limited (emergency) equipment rating. However, R3.3.2.2 is only applicable to single contingency events -- that is, events P1, P2, P6 in Table 1. Shouldn't this concept of allowable system adjustment duration apply uniformly to all Planning Events P1-P9 in Table 1? 17. R3.5 allows generation runback for single and multiple contingencies -- that is, for ALL planning events P1-P9. It appears that this requirement lends itself to be included as another bullet item in the Performance Requirements at the top of Table 1. In fact, why not define what comprises System Adjustment (see comment above) and then tabulate the system adjustments that are (not) permitted for each planning event within Table 1? 18. System Stability studies: The standard must clearly define what types of stability analyses fall under this umbrella term. While it is generally understood that this includes angular stability analysis, which is the only one that is explicitly mentioned in the Table 2 footnotes, the standard does not indicate whether dynamic voltage stability analysis or small-signal stability analysis are also expected to be done as part of system stability studies. 19. Requirement R2 and its sub-requirements are intended to address all aspects of Planning Assessment. However, it is unclear which requirement(s) in the draft standard cover the scope of R1.3.12 in the existing TPL-002 and TPL-003 standards, which requires "Include the planned (including maintenance) outages of any bulk electric equipment at those demand levels for which planned (including maintenance) outages are performed. Further, we are unsure if the direction provided in FERC Order 693 paragraphs 1724 and 1786 with respect to planned (maintenance) outages have been adequately and clearly addressed in the draft standard. Can the SDT point us to the specific requirements that address the above issues? 20. We recommend that the SDT give consideration to acknowledging or addressing the directives in FERC Order 890 for performing transmission system loss analysis and economic assessments --

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Commenter	Yes	No	Comment
			can they be considered within the scope of reliability assessments? EDITORIAL COMMENTS 21. R4.5.1 and R4.5.2 -- It appears that the intent of these sub-requirements within R4.5 for System Stability study is very similar to the intent of R3.3.3 and R3.4 for Steady State studies. If so, then why have different heirarchical numbering for the latter case? Suggest changing R3.3.3 and R3.4 to sub-requirements R3.4.1 and R3.4.2 respectively within R3.4 for Steady State study. Table 1 22. Event P3 -- The performance requirement in column 3 "Interruption of firm transfer allowed" should be simply "NO" (outaged dc line performance is not applicable). 23. Event P5.3 -- Clarify if the "loss of another transformer" is intended to be the loss of a transformer with low-side voltage >300kV or *any* transformer in the BES. 24. Event P9.1 -- Is the one mile intended to be one *contiguous* mile? If so, recommend inserting the qualifier "contiguous" to claridy the intent. 25. Event P9.6 -- The contingency description is very confusing regarding the role of spare transfomer. Is spare transformer part of the system adjustment? Please reword to clarify the intent. 26. Extreme Event Descriptions -- Items 3e and 3f are repetitions of items 3c and 3d. Delete any one pair. Item 3h is too vague --- either provide more specificity or delete it. Table 2 27. Extreme Events - Evaluation Requirements -- Inclusion of item 9 (3-ph fault with loss of all generating units at a station) in the table is inconsistent with Q.33. 28. Having both bullets at the beginning of the table and footnotes at the end of the table, which deal with similar subject matter, tends to be confusing and should be addressed. 29. The different types of Stability analysis (steady state voltage stability, dynamic voltage stability, dynamic generator unit angular stability, and dynamic inter-area power oscillation stability) be clearly and concisely stated in one location and the perfomance requirements for each type of stability should be more clearly stated in appropriate locations.
Response: 1. The standard has been revised (see Requirements R9 through R13) to identify specific entities responsible for providing the required information. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including			

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Commenter	Yes	No	Comment

the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.
R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.
R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.
R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.
R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information

2. The SDT has determined that DSM is included in MOD and is no longer explicitly included here.
3. The SDT understands your concern and has modified the requirement (now Requirement R10) to clarify intent. The intent is to include modeling information for firm Transmission service data, Interchange Schedules, and resources required to serve Load.
4. The SDT agrees with your comment concerning the ambiguity of the term "Firm Transfer". The revised requirement (now Requirement R10) and revised Table 1 use the existing NERC Glossary Term Firm Transmission Service, as you suggested. However, the SDT does not agree that curtailment of Firm Transmission Service should be permitted for events P1-P4.
5. Few commenters raised this concern, so the SDT is uncertain whether the necessary information could be obtained from the RC in all regions. The ultimate source of the information is the TO and the GO. In the revised standard, this requirement has been separated into two requirements to clarify the intent for transmission equipment planned outages and long-term outages (Requirement R11) and generation equipment planned outages and long-term outages (Requirement R12). If the TO and GO provide the necessary information to the RC in a given region, it is possible that the TO and GO could arrange for the RC to provide the information to the PC to demonstrate compliance with the requirements or, alternatively, send the information to both the PC and RC.
6. The SDT has modified the standard based on various comments. The phrase "in accordance with the documented criteria of the Planning Coordinator" has been deleted. This requirement has been further revised and separated into two requirements applicable to the Resource Planner and Transmission Planner, respectively.
7. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.1.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document which senstivities are more significant to study System responses. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed. For example an entity's base case Load level may be modeled as a 50/50 Load level which represents what the entity considers normal peak weather conditions. A sensitivity to that may be a 90/10 Load level case which represents extreme weather conditions.

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Commenter	**Yes**	**No**	**Comment**

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

8. Requirement R2.5.2 was changed for clarification.

R2.5.2 Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

9. R2.6.1 – R2.6.3 – Requirement R2.6.2 was changed for clarification.

R2.6.2 For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

10. Requirement R8 (old requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT believes that initiation dates are required for near-term Corrective Action Plans to give an indication that the Corrective Action Plans can be implemented in time.

11. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

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Commenter	**Yes**	**No**	**Comment**
12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and Requirements deleted R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". 13. The SDT has revised Table 1 to include N-0. 14. The term "System adjustment" is used in the existing TPL Standards, and is intended to have the same meaning in the proposed TPL standard, and includes both manual and automatic actions. 15. The SDT has made extensive changes to the tables to address these concerns. 16. and 17. The use of the defined term 'Facility Ratings' includes time elements which accommodate your concern. 18. You must perform any Stability analysis that is required to meet the performance requirements. 19. Requirement R11 contains this language. 20. The scope of the SAR and standard being prepared is only related to reliability assessments. 21. The SDT attempted to make Steady State and Stability identical but this was not always possible. 22. The SDT believes that the reference to the outaged DC line is appropriate. 23, 24, 26, and 27. P5.3 is intended to be the loss of a second transformer with low-side voltage >300 kV. P9.6 was to address the FERC directive in Order 693 to consider spare equipment strategy. In Q33 the SDT posted a question to the industry to request guidance on whether simultaneous tripping of all generating units in a power plant should be included the Extreme Events in Table 2 (on Stability Studies). The SDT has revised Tables 1 and 2 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. Tables 1 and 2 have also been revised to address your comments on P3 and P9.1, the repeated Extreme Event Items 3c – 3f and Item 3h. For P9.1 (P7.1 in the second draft), the SDT did not change the table to include "contiguous" for the 1 mile (or less) exclusion because the standard does not limit the number of instances where two circuits can share a common tower only that each exclusion applies to a length of one mile or less. 25. The SDT agrees and has eliminated that requirement. 28. Editorial change made to alleviate confusion. 29. You must perform any Stability analysis that is required to meet the performance requirements.			
APS	☑		R 2.5.1 and R 4.6 require plant stability studies for all generators greater than 20 MVA for changes in excitation system or PSS addition. Generally plant stability is a problem only for large plants with large generators. Changes in the excitation system of a small generator or PSS addition does not significantly impact the plant stability. In fact, in most cases it improves the plant stability. When an excitation system or a PSS is commissioned in the field, part of the commissioning tests ensure that turbine-generator is stable and that the performance of the excitation system and PSS are acceptable. If an excitation system change or PSS addition is causing a plant stability problem in simulation, it is generally a data issue and can be best handled in MOD standards. Requiring stability studies to be redone does not in any way contribute to the system reliability. There are hundreds of old generators in the US which are going through excitation system retrofits in a given year. Requiring a stability study for each change would add additional study burden without any value to the system. This is unnecessary work with little consequence on the system performance or reliability.

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Commenter	**Yes**	**No**	**Comment**
			Note: We have additional comments on these standards but they have been covered by comments from WECC. We fully support all of those comments.
Response: Those values are based on Large Generator Interconnection Procedures as approved by FERC. Unit controls are an integral part of the power system and must be analyzed when changes are made.			
BPA	☑		Support comments sent by WECC. In addition,BPA has the following comments: 1. R2.3.1 - The way the requirement is written sounds like the short circuit study should be run after changes are made to the BES. The study needs to be done sufficiently in advance to allow for needed equipment replacements as a result of the study. Also, "current" in the first senetence should be changed because it is confusing whether it refers to "present" or "amps". 2. There needs to be better definition what is meant by "bus tie breaker". It is assumed this includes both bus tie breakers between a main and auxiliary bus, as well as bus sectionalizing breakers between two main bus sections. 3. In general the table seems unnecessarily complex. It would appear to make more sense to group events by performance as done in the previous Table 1. Also, in general the resulting events for the element contingencies in the table should be compared and like events grouped together since they would be are modeled the same and show the same performance in powerflow studies. 5. P9.1 - It is recommended to exclude multiple circuits sharing a common structure for no more than three miles, rather than one mile. Our analysis shows river crossing systems can be up to three miles and it is impractical to plan for common corridor outages of up to this distance. 6. Planning event P9.6 is the same as P8.3 with the only difference being the restoration time. 7. Regarding extreme event descriptions: - Item 3.a is not a Transmission Planning, but is relevent for Resource Adequacy. - Item 3.b is an operational issue not relevent to Transmission Planning. Successful cyber attack would need to be defined. Also, how would the consequences of a successful cyber attack be predicted? - Regarding item 3.c, generation capabilities should already be modeled in base cases within the planning horizon. - Items 3.d through 3.f are not relevent to Transmission Planning. These are Resource Adequacy issues within a short term operational horizon. - Items 3.e and 3.f appear redundant to items 3.c and 3.d. - Item 3.g is not really a planning issue. The system should be designed to meet required

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Commenter	**Yes**	**No**	**Comment**
			performance for selected contingencies regardless of age or maintenance pratices. - In general, the Extreme Events layed out in the previous Table 1 is a much more practical approach to planning the transmission system.
Response: 1. Requirement R2.3.1 has been deleted. In Requirement R2.3, the wording has been revised to be clear that an annual assessment is required and what studies may be used. Requirement R2.6 provides further detail about which past short circuit studies may be used. Requirement R4 explains the conditions that the studies should analyze. 2. The SDT has included a proposed definition of a Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 3. Tables 1 and 2 have been revised to provide greater clarity. 5. The SDT notes that distances greater than a mile present comparability issues with regard to other situations such as bay crossings, harbor crossings, and other longer spans. The SDT has not revised the requirement as a result in the interest of maintaining comparability without opening the waiver up to other situations. 6. The SDT has deleted P9.6. 7. With regard the Items 3.e and 3.f appearing to be redundant to items 3.c and 3.d., the SDT agrees and has made the appropriate changes to the standard. With regard to the other comments about the Extreme Events, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example paragraph 1834 include "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. The SDT believes that the Extreme Event items that the commenter has raised concerns about are consistent with the list of examples provided in paragraph 1834. Further, the SDT notes that while the commenter is correct that some of these events have traditionally been treated as deliverability issues, nonetheless they will dramatically impact the reliability of the interconnected network and are logical Extreme Events for which the probability and consequences should be evaluated when considering ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments.			
BCTC	☑		1. We have some questions of clarification for the Standards Drafting Team, that may resolve some of our concerns. (i) Is it the intention of NERC that the more stringent performance requirements in this standard would be applicable for determining System Operating Limits before Transmission Owners are able to implement Corrective Action Plans? The BCTC system is part of the western interconnection and BCTC is a member of WECC. WECC members apply a principle that Planning Standards are also applicable for determining System Operating Limits. If the answer to this

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Commenter	**Yes**	**No**	**Comment**
			question is "no", then BCTC may be able to support some aspects of raising the bar, with the understanding that SOLs would be determined based on the performance standards that the system is planned to. (ii) Has the Standards Drafting Team considered how Transmission Planners will address discrepancies between Corrective Action Plans for this standard and the reality of what can be constructed due to regulatory approvals, siting problems, financing issues, etc.? For example, is it the intention that Transmission Planners should continue to study Corrective Action Plans to meet an N-1-1 Planning Event (e.g. P5-1) without generator tripping when the practical situation is that we may be fortunate to be able to build to meet N-1 with some generator tripping? We are concerned that if we cannot meet the performance requirement for P5-1 due to delay or denial, continuing to assess Corrective Action Plans to meet P5-1 does not provide much useful information compared to planning to meet a doable target. Item 2 below provides a proposal to address this. 2. There is always the possibility that a regulator may deny funding for a Corrective Action Plan or approve funding for a Corrective Action Plan that does not fully meet the performance standards, a siting process may delay or block a Corrective Action Plan, or some other process may frustrate the ability follow through with a Corrective Action Plan to meet NERC performance standards. To avoid the need for a Transmission Planner to continue to study Corrective Action Plans that cannot be implemented, we suggest adding the following Requirement R2.7.6: The Planning Assessment is not required to include a Corrective Action Plan and address the subsequent requirements (of R2.7) in cases that (a) an applicable regulatory agency has ordered that a Corrective Action Plan is not to proceed or that an alternative Corrective Action Plan that does not meet the performance standards is to be implement or (b) the Transmission Planner has documented evidence indicating that such an outcome is likely to occur. Other Requirements for Five and Ten year Assessments may also be exempted depending on the regulatory order. The Planning Assessment will include evidence of the order. 3. R3.3.3, R3.4, R4.5.1, R4.5.2 - A rationale for the selected contingencies should be sufficient. It should not be necessary to explain why the remaining contingencies would produce a less severe result. 4. Table 2, P1 should include shunt devices. 5. A definition or reference to a definition for Firm Load and Firm Transfers is required. The present situation is that these terms are "defined" as those loads and transfers that can be supplied while meeting Category B requirements. In other words, the standards define the terms. The commercial uses of firm and non-firm may not be applicable and they actually mean non-recallable and recallable service, not directly related to system performance, but incorporating aspects of

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Commenter	Yes	No	Comment
			reservation times. 6. Extreme Events of Tables 1 and 2 should not be subject to the same study requirements as Planning Events. Table 1 Extreme Events need not be studied for both the Near Term and Long Term Horizon (ref. R3.4, R3, R2.1 and R2.2) and for all five years of the Near-Term Horizon (ref R3.4, R3, R2.1). Table 2 Extreme Events should not be required for all five years of the Near-Term Transmission Planning Horizon (ref. R4 and R2.4). When conditions warrant, only a single assessment representing a selected reasonable planning horizon should be required, and an update required only when past studies are no longer representative. We are concerned that many of the proposed Table 1 Extreme Events (Item 3. a, c, d, e, f) are resource adequacy issues (we also observe that c and e appear to be identical). Transmission Planning Assessments of these events should be initiated at the request of Resource Planners. It should not be necessary for Transmission Planners to initiate and maintain current studies of these Extreme Events. We suggest that Extreme Events be removed from R3 and R4 and addressed in a separate Requirement. 7. The Purpose of this standard should be restated as: Establish requirements for Planning Assessments, including Corrective Action Plans, to be conducted over range of forecast conditions based on system planning performance requirements. Explanation: This revised wording more accurately describes the content of the standard. The Requirements of this standard are to perform Studies and Assessments. The performance tables are referenced by the Requirements and are supporting to the Requirements, but are not a "capital R" Requirement.
Response: 1. NERC, in its response to FERC's NOPR on the FAC-010, FAC-011, and FAC-014 standards, committed to revising the FAC and ATC standards when there is consensus on the TPL standards. The intent of the Corrective Action Plan is to establish a doable set of actions that are to meet the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of corrective actions being delayed. It is the entity's responsibility to assess these impacts and adjust the next set of actions planned to meet performance. The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc. In addition, generation tripping for single Contingencies has been added back into the standard and the N-1-1 performance requirement has been revised to allow generator tripping and Non-Consequential Load dropping. 2. The SDT does not believe that it is necessary to add the words concerning regulatory delays or denials. The intent of the Corrective Action Plan is to establish a plausible set of actions that, when implemented, achieve the performance requirements. Senstivitiy studies have been specifially added to the standard to allow the planner to assess the impact of modification to or delay of a corrective action plan. It is the entity's responsibility to assess the impacts of a modification or implemetation delay and adjust the next set of corrective actions or modify the proposed plan to meet the performance requirement as prescribed in the standard. The standard also requires that the assessment cover more than the ten year period if the entity deems it necessary to accommodate any long range projects that may take years to complete due to ROW acquisition, hearings, etc. 3. The SDT believes that it is necessary as part of a complete documentation set explaining why and what was done.			

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Commenter	**Yes**	**No**	**Comment**
4. This was added as requested. 5. In reviewing this comment, the SDT noted that Firm Demand and Interruptible Load are defined in the NERC Glossary. The SDT believes Load that is not Interruptible Load as defined in the NERC Glossary best fits the intention of the requirements pertaining to Firm Load in the TPL standard. Therefore, the SDT modified the references to Firm Load to refer instead to non-Interruptible Load in the TPL standard. With this change, Firm Load does not need to be defined in this standard. 6. The SDT agrees with the comment that Extreme Events should not be subject to the same study requirements as Planning Events; however, the SDT proposes to resolve the issue by clarifying the study requirements in the table and the text without removing the Extreme Events from Requirements R3 and R4 and addressing Extreme Events in a separate Requirement. With regard to the comments about resource adequacy issues, as noted in the BPA 7 answer, these events that have been traditionally considered resource adequacy issues are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. As a result, the Transmission Planner/Planning Coordinator should investigate these Extreme Events regardless of whether the Resource Planner considers them to be an issue or not. In this way, the Transmission Planner/Planning Coordinater considers ways to make the Transmission System more robust with Operating Procedures and/or System improvements that are reasonable in cost in comparison to the probability and consequences of the Extreme Event. The SDT did not change the standard with regard to these comments. 7. Since most commenters did not express concern with the Purpose language, the SDT felt that no change was necessary.			
CAISO	☑		1. First, and as a general matter, the TPL-001 standard needs to accurately reflect the roles of PA'S and TP'S in areas with organized competitive markets and where the PA'S and TP'S are not vertically integrated utilities. In those areas, the TPL standard should recognize that compliance with the standard is achieved through the publication of a Plan that identifies system needs – and leaves open to the marketplace the specific mix of resources that investors construct to meet those needs. As a result, the Plan need not be, and should not be, prescriptive as to the resource mix that must be achieved. It is important for plans to be equally open to generation, demand response and transmission and not be presecriptive to the actual resource mix. Further, not all organized competitive markets have a mechanism in place to develop an integrated resource and transmission plan to meet future needs. Some markets conduct forecast assessment, thereby providing signals to market participants to make investment decisions. 2. Similarly, reflecting the divested nature of the industry in areas operated by ISOs and RTOs, the modeling standards should be reviewed to make sure that asset owners (e.g., generator owners and transmission owners) are required to give information in the level of detail and granularity that will allow PA's and TP's to develop plans and models consistent with these standards. 3. As highlighted in question 16, DSM should be considered an acceptable solution to system needs. However, DSM is generally considered in meeting resource requirements rather than as one of means to relieve transmission constraints. In planning studies, loads that are identified as DSM type (contracted or potential) are modeled as firm loads for reliability assessment. We would therefore seek the SDT's suggestion on how specifically DSM should be explicitly modeled or used to aid in

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Commenter	**Yes**	**No**	**Comment**
			achieving transmission reliability in the planning horizon. Further, the drafting team must consider whether DSM providers are covered in the Compliance Registry and how the NERC Standards should obligate them to provide the requisite information to PA'ss and TP's so that they are fully taken into account. 4. Finally, the standards need to be improved to better distinguish the responsibility of Planning Authorities versus Transmission Planners. Currently, the Standard refers to both entities as carrying out the requirements. This appears to be reundant.
Response: 1. The SDT believe that the standard is not prescriptive in the way described in the comments. 2. Comment is beyond the scope of the standard under development and should be addressed through proposed changes to the appropriate MOD standards. 3. The use of DSM is optional. Requirement R2.7.1 has been modified based on comments received to use "may include" instead of "including". The standard does allow for consideration of DSM but other factors may disallow inclusion of DSM in the Corrective Action Plan. The amount and uncertainty of DSM needs to be justified by the entity which includes it in its Correction Action Plan. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. The standard is applicable not only to the Transmission Planner but also to the Planning Coordinator and the Resources Planner. These entities are expected to establish relationships to provide for intergrated analysis and resultant Corrective Action Plan which may include generation, transmission and DSM components. 4. Requirement R2 specifies that each entity is responsible for "its" portion of the BES. Even so there will likely be overlap and joint responsibility in some instances as identified in Requirement R5.			
CenterPoint	☑		1. TPL-001-1 focuses solely on reliability to the exclusion of economic cost/benefits, prudent avoidance, and landowner impacts, which have been the hallmarks of good utility practice that have governed transmission planning and construction for decades. FPA section 215(i)(2) "does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." However, adherence to TPL-001-1 as currently drafted, will require, de facto, the construction of additional transmission facilities. CenterPoint Energy believes this standard excludes proven, historical good utility practice to reach far beyond what is intended by the FPA. TPL-001-1 contains an excessive number of requirements (over 50). The SDT should consider the removal or modification of the following unnecessary, redundant or overly prescriptive

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Commenter	Yes	No	Comment
			requirements: 2. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 3. R2.1.3 and R2.4.3 should be removed because they introduce new, vague requirements. 4. R2.2. Analysis beyond five years has little value due to the speculative nature of predicting load and generation growth. Furthermore, ERCOT does not annually create Long-Term Planning Horizon cases because ERCOT does not believe it is necessary. This requirement should be removed. 5. R2.5 and R4.6. These requirements are overly prescriptive and unnecessary for the reasons stated in the response to Q32. They should be removed. 6. R2.7.1 through 2.7.5. Requiring Corrective Action Plans that address how performance requirements will be met is reasonable; however, these standard requirements are overly prescriptive and unnecessary. R2.7.1 through R2.7.5 would result in the development, documentation and explanation of fictitious solutions to fictitious problems. They should be removed. 7. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 8. R5. The roles of the Transmission Planner and Planning Coordinator are already addressed in the approved NERC definitions and further described in the approved NERC Reliability Functional Model. This requirement is unnecessary and should be removed. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer, monopolar DC line) with generation adjustments is impractical and overly burdensome. For multiple contingencies, CenterPoint Energy recommends including only two-circuit tower lines and the two components (generator, Transmission circuit, transformer, monopolar DC line) that would be cleared by a breaker failure (i.e., stuck breaker).
Response: 1. The SDT's understanding is that the ERO has the authority to set performance requirements for reliability. 2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD			

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Commenter	**Yes**	**No**	**Comment**
standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 3. The SDT feels it is appropriate to set a minimum level of sensitivity cases to be looked at. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The SDT has modified Requirements R2.1.3 and R2.4.3 to clearly stipulate that the entity shall provide rational for why sensitivities on the list were or were not included in the sensitivity studies and that the entity may consider additional sensitivities that are appropriate for its own system. The Standard requires that deficiencies identified from the results of the current studies need to be addressed via Corrective Actions Plans while leaving it at the entity's discretion to decide which deficiencies, if any, identified through sensitivity studies should be addressed by the Corrective Action Plan. **R2.1.3**. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied: **R2.4.3**. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 4. The SDT feels that this requirement is appropriate based on its understanding of planning practices throughout North America. This is also mentioned in FERC Order 693. 5. See response to Q32. 6. After careful consideration, the SDT agrees that if the Corrective Action Plan is going to include "committed" and "proposed" projects, they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire NERC footprint. Therefore, the SDT has modified Requirement R2.7.1 and deleted the original Requirements R2.7.2 through R2.7.4 to reflect "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 7. FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event. 8. The Functional Model is intended as a guide and aid in drafting reliability standards. Nothing stated in the Functional Model is enforceable in and of itself. Only requirements in approved reliability standards, which may mirror the Functional Model assuming that industry consensus is received on the subject matter, are enforceable.			

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Commenter	**Yes**	**No**	**Comment**
9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
HQTE	☑		1. We think that the proposed fusion of previous TPL-001 to TPL-004 and the addition of more specific contingencies involves too much change at once. It would have been better to make specific change to each individual standards. That way, it would have been more practical to evaluate the impact of the proposed changes. 2. A major concept before evaluating the impact of a standard is to know on what system it will be applied to. In the tables, the notion of a voltage treshold (>300 kV) is introduced. It is our interpretation that the standard as drafted applies only to BPS elements part of that treshold (>300 kV) and not every ">300 kV" element. The SDT should indicate if they have the same interpretation as ours. 3. We reiterate our comment that it would be preferable to have only one table that would include both steady state and stability contingencies with their respective expected performance. 4. There might be some protection standards that would need to be developped/clarified before some proposed changes in this standard. 5. The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments from Central Maine Power.
Response: 1. Much of the wording and underlying concepts are the same for the four standards today – the major difference being that each refers to normal, single, multiple or extreme Contingencies. All four use the same table. Merging them into one standard has simply eliminated much of the duplication and brought together the smaller portions of each standard that were different. Past experience has shown that since the four are so closely related that a change in one has a tendency to reflect a change in another – merging the four together helps keep all the changes and relationships in a single point of view. Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of Order 693 “directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process”. In addition this Order, in conjuction with Order 890, enurmerate attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with Orders 693 and 890 without being unduley burdensome. 2. As proposed, the standard is intended to apply to all BES (not BPS) Facilities, but for some events the performance requirements are different for Facilities above and below 300 kV. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure			

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Commenter	**Yes**	**No**	**Comment**
not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. 3. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. Based on industry feedback, the SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 4. Since the SDT is considering specific references to items such as SPS, the SDT will need to address any direct effect on other standards. The SDT encourages the commenter to provide comments on any specific instances where such a clarification or change may be needed. In addition there is a standard under development that will be addressing integration of all Protective Systems. That team will be coordinating with the TPL team. 5. Base Case has been deleted as suggested.			
NPCC RCS	☑		The SDT has made an effort to define Base Case, yet has not used the term in the standard. At a minimum, Base Case should be referred to in sections 2.1.1, 2.1.2 In addition to the comments by Central Maine Power.
Response: After reviewing the comments to this proposed definition and the use of the term "base case" in the standard, the SDT determined that "Base Case" does not need to be a defined term.			
Central Maine Power National Grid New England ISO NU NSTAR United Illuminating	☑		1. There should be a "P0" standard that applies to system performance without any contingencies. 2. Standard should be clear that stabiltiy analysis is not required for Long-Term Planning Assessment. 3. R.1.1 Load forecasts should be addressed in MOD standards, not TPL. 4. R 1.4 This should only refer to known long-term outages, not planned outages. Delete "including protective relays"; this is addressed through other provisions. 5. R.2.1 Shorten "Near-Term Transmission Planning Horizon Planning Assessment" to "Near-Term Planning Assessment". 6. R 2.2 Shorten "Long-Term Transmission Planning Horizon Planning Assessment" to "Long-Term Planning Assessment". 7. R2.1, 2.2, 2.3 & 2.4 – The initial paragraph should have identical language regarding 'annual', and 'current or past' aspects.

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Commenter	**Yes**	**No**	**Comment**
			8. R2.1.1 There should not be a requirement to look at years one and two; a 5 year study should be sufficient. If there has been an ongoing 5 year study, there should be no major unexpected problems occurring in years 1 and 2. Studies of earlier years should only be required if an unanticipated event occurred that had not been considered in prior studies. The TPL should not address shorter term "Operating Studies" or operating issues. 9. R 2.2.1 Modify to "If any known projects have a lead time that is longer than ten years, the Planning Assessment shall be extended accordingly." 10. R 2.6 Steady-state, short circuit, and stability analysis should be required no more than every 5 years unless there is a significant change the system. 11. R 2.6.1 Remove reference to "market structure changes". The purpose of it's inclusion is unclear. 12. R 2.7.1.1 Project initiation date should be deleted. If it is retainted, it needs to be defined. 13. R 2.7.3 Committed and Proposed projects should be defined. 14. R 3.2.1/R 4.3 - What is the intent of this requirement? There should probably be an MOD associated with Generator Owner requirement to provide related generator protection/ limiter data or other plant information. 15. R 3.4/R 4.5.2 Remove the requirement to implement changes to reduce or mitigate the likelihood of such consequences of Extreme Events. This may not be reasonable or achieveable. 16. R 3.2 Sectionalizing schemes shall be considered when reflecting the post-contingent system. 17. R 3.2.2 - Propose deleting this. Line ratings should already take relay loadability into account. 18. R 3.3.2.1 - Proposed deleting "expected duration". This would be dependent upon the damage to the element due to the iniating event and other factors. 19. R 3.3.2.2 - The requirements of this section do not match P6. 20. R 3.3.3 - Change introductory language to read "Those multiple Contingencies that are…"

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Commenter	Yes	No	Comment
			21. R 3.5 - Generation tripping should be allowed as well as generation run-back. In addition, all performance requirements shall be met, rather than just meeting facility rating requirements. Suggested lanague "Manual and automatic generation run-back and/or generation tripping is allowed as a response to single and multiple Contingencies as long as the performance requirements of this standard are met." If these changes are accepted, R 3.6 can be deleted. 22. R 4 and R 4.1 - The language should be made similar to R 3 and R 3.1. 23. Suggest bringing language similar R4.4 into the R 3, the steady state section. 24. R 4.2 - High speed automatic reclosing schemes shall be considered. 25. R 6.3 - Change to read "Planning Coordinators of neighboring impacted areas". 26. Table 1 3 b and c Extreme Event descriptions are vague concepts that cannot be practically simulated. 3 d and e are not reasonable or practically useful to simulate. 27. Table 1, P8 - Language needs to be clarifed as to how the 300 kV threshold is to be treated for transformers. Is this for the high side, low side, or both sides? P5 is much clearer. 28. Table 2 - Clarification needs to be made that the faults being simulated are permanent faults. This can be addressed under the "Performance Requirements" portion at the beginning of the table, or modify each fault description. 29. Table 2 P9. Recommend that this be changed to require that faults should be on different phases of each of two adjacent transmission circuits on a multiple circuit transmission tower 30. Table 1, P9(6) and Table 2 P9 - It is unclear as to what is meant by "A spare transformer inserted to replace an outaged transformer followed by System adjustments". Unclear as to what is to be tested. 31. General comment - Transmission System is used throughout the document and is an undefined term The New England Transmission Owners and ISO New England transmission planners met several times to discuss the proposed standard and develop consensus comments based on our experience. The preceding comments are what was developed.

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Commenter	**Yes**	**No**	**Comment**
			Attached to the e-mail sending these comments is the September 12 Draft 1 TPL-001-1 Reliability Standard in Word format, red-lined with changes to the posted standard which are intended to reflect all of the comments above. This document was maintained by Central Maine Power Company during the course of the New England transmission planner discussions, and any variance (though none are expected) in not intended. It is expected that this red-lined TPL document will be helpful to the ATFN SDT in reviewing our comments.

Response: 1. The SDT concurs for the steady state performance requirements and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. However, "normal System" is already included as part of the description of the initial System conditions associated with the fault for the stability study. Therefore, it is not necessary to include P0 in Table 2.
2. The SDT agrees. The requirement only specifies Near-Term.
3. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
4. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725.
5. The intent of the suggestion was adopted.
6. The intent of the suggestion was adopted.
7. Identical language was not used; the same words were used in a different order and context. Requirement R2 and the following four sub-requirements each address a slightly different aspect of what studies are to be run. Requirement R2 only mentions current and past in general terms since more specifics are provided in the sub-requirements. Requirement R2.1 makes reference to "annual current" studies to emphasize the fact that the Requirements R2.1.1 and R2.1.2 require specific studies be run each and every calendar year. Requirements R2.2 is consistent with Requirement R2.1.1 in that it requires a specific run each and every calendar year. Requirement R2.3 does not require specific run every year but allows for current or past to support the Assessment; this is also true for Requirement R2.4.
8. Requirement R2.1.1 requires you to study years one "or" two and five. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the Operating Horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required. Areas with faster growth should appreciate the extra studies.
Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." Requirement R2.1 allows for the Planning Assessment to be "...supplemented with qualified past studies…" If you have past studies which are applicable, the standard allows for such.
9. The SDT believes that the present draft language captures the same concept.
10. The SDT agrees with your recommendation and has revised Requirement R.2.6.1 to show a five year shelf-life.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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Commenter	**Yes**	**No**	**Comment**
~~structure changes~~ the study shall be five calendar years old or less. 11. The SDT concern was that such structure changes could potentially affect dispatch scenarios, or even transfers being modeled – both of which are sensitivities. 12. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 13. After careful consideration, the SDT agrees that if the standard is going to include "committed" and "proposed", they will need to be defined. However, the SDT agrees that it will be very difficult to develop definitions of "committed" and "proposed" that are applicable for the entire continent. Therefore, based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between "committed" and "proposed" projects. It also lists examples of what is intended by the word "actions". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. R6.2.2 - Whereas the SDT agrees that the suggested re-phrasing has merit, the proposed rephrasing is potentially problematic because "Long-Term Planning Assessment" is not a defined term. 14. The intent is that what is modelled is true to real-life expectations. Changes to MOD are not within scope. 15. The SDT feels that this is an appropriate requirement based on understanding of existing practice within North America. 16. That was the intent of this requirement. 17. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment. 18. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 19. Requirement R3.3.2.2 was changed to correct this discrepancy.			

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2 Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 20. The reference to Table 1 will need to be included because Requirement R3.3.3 applies only to Steady State performance to distinguish this requirement from those in Requirements R4.5.1 and R4.5.2, which apply to Stability Performance. 21. The SDT agrees and has changed Requirement R3.5 **R3.5** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: **R3.5.1**. All Facilities shall be operating within their Facility Ratings. **R3.5.2**. Such action would not violate safety, equipment, regulatory or statutory requirements. **R3.5.3**. A sustainable, stable, operating condition is maintained 22. The SDT attempted to make this language similar to the extent possible. 23. The SDT believes that Requirement R2.7 covers this matter for Steady State but will discuss this matter further for subsequent drafts. 24. The intent of this requirement is to model the system as it would be operated and high speed reclosing would therefore be included. 25. The SDT believes that your comment has already been addressed by the words "affected entities" (now directly adjacent Transmission Planner) in Requirement R8 (old Requirement R6). Impacted is difficult to measure. In addition, the purpose of the "peer review" is to help ensure that a Corrective Action Plan is inclusive and some potentially impacted areas are not overlooked. 26. As noted in the BPA 7 answer, these events are included as Extreme Events to be consistent with FERC Order No. 693 and because such events could dramatically impact the reliability of the interconnected network. 27. The SDT agrees that the language for P8 needs to be clarified with regard to the 300 kV threshold. As a result, the SDT has made changes to the standard to clarify the 300 kV threshold. 28. The SDT agrees and has changed the standard to clarify that the faults being simulated are permanent faults. 29. The SDT has made the recommended change in P7. 30. This item was deleted. 31. Transmission is a defined term in the NERC Glossary as is System.			
City Utilities/Springfield	☑		Requirement R3.2: Contingency analyses representing only the removal of elements that System protection is expected to automatically disconnect which includes Consequential Load Loss is a reduction in reliability. Excluding the contingency analyses between all elements including those with manually operated switches will result in lowering existing reliability standards and ultimately limit the load restoration capabilities of the BES. Minimum performance standards should be adhered to for all applicable contingencies including outages of elements that may be switched both automatically and manually taking into account controlled load curtailment that is allowed. Requirement R3.3.2.1: The expected duration of Consequential Load Loss was noted to be required in a Planning Assessment following a single Contingency without any indication as to the assumed

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Commenter	**Yes**	**No**	**Comment**
			cause of the outage. The basis for such estimations of time needs to be defined such that these assessments are developed on a consistent basis.
Response: 1. One of the drivers for assessing the System performance based on removing all elements that System Protection is expected to disconnect (breaker-to-breaker) upon clearing the fault is to address concerns expressed in interviews by NERC TIS and FERC. The premise is that the assessment must examine all phases after a fault occurs. This includes the initial response of the System immediately after the fault clears, as well as after any existing or planned switching actions, such as the ones to which the commenter refers. 2. The proposed TPL-001-1 standard does not place limits on the amount of Consequential Load Loss or the outage duration. In Requirement R.3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is necessary to obtain this data to evaluate the future need for and establish a basis to define maximum amounts of Consequential Load Loss that would be allowed.			
CPS Energy	☑		1. R1.1. This is a modeling requirement and should be incorporated into the modeling (MOD) standards. Remove or modify this requirement to eliminate any redundancy with existing modeling standards. If certain subrequirements of R1.1 of TPL-001 are not currently requirements in a MOD standard, it should be questioned, then, whether or not these specific subrequirements are actually needed in ANY standard. 2. R2.2. ERCOT does not study the Long-Term Planning Horizon because ERCOT does not believe it is necessary. Remove or modify to state "as applicable by region." 3. R2.7.1.1 Duration of projects vary between Transmission Owners and statement of the project initiation date has no value to reliability. 4. R3.3.2 Relay loadability is considered as an MLSE component to the circuit rating as identified in MOD-008 and MOD-009. 5. R3.3.2.1. The requirement to identify consequential load loss for single contingencies in the Planning Assessment is unnecessary and burdensome and should be removed. 6. R3.6 Automatic generation tripping should be allowed for radial-connected wind resources. 7. Table 1 - P6.1, P6.3, and P6.4 These events are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 8. Table 1 - P9.1 Loss of double-circuit tower lines are triggered by a single credible event and should not allow for loss of Non-Consequential Load. 9. Table 1 and Table 2 - P4, P5, P8, and P9. Including all combinations of two components (generator, Transmission circuit, transformer) with generation adjustments is impractical and overly

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Commenter	**Yes**	**No**	**Comment**
			burdensome. For multiple contingencies, include only double-circuit tower lines and the two components (generator, Transmission circuit, transformer) that would be cleared by breaker failure.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2. The SDT believes that the purpose of the long term horizon is to uncover any unexpected trends that might appear after the first five years. Although planning may not be performed as stated in the draft standard, the standard does provide a level of confidence that unusual or unexpected trends or events could always affect the current planning process and allows for planners to propose potentially long term economic solutions that could not be envisioned in the shorter term.
3. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.
4. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. The SDT has not made changes in response to this comment.
5. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
6. The SDT has made a change to allow for tripping under certain conditions.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:
R3.5.1. All Facilities shall be operating within their Facility Ratings.
R3.5.2. Such action would not violate safety, equipment, regulatory or statutory requirements.
R3.5.3. A sustainable, stable, operating condition is maintained.

7. These events are on lower voltage facilities on the BES. The probability of the outage of one breaker or a bus section is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker or lower voltage bus section. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard.
8. This event is a lower probability event, for example the probability of the outage of one common tower event is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load

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Commenter	**Yes**	**No**	**Comment**
or interruption of firm Transmission service for the loss of a common tower event. The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 9. The analyses of the combinations of two components are required by the existing TPL standards. The SDT understands the concerns in the potential increase in work load. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts.			
Entergy	☑		1. Significant Increase in Study Activity Workload on Transmission Planners The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The more specific format and additional requirements of the "Corrective Action Plan" require the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. 2. Implementation Plan Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and increasingly expensive due to the environmental and social issues associated with new Transmission. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners, extraordinarily expensive, and possibly unachievable. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. 3. Design and Construction Constraints Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on commodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned due to the competition for both human and material resources.

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Commenter	Yes	No	Comment
			4. Cost-Benefit Analysis It will be extremely expensive, requiring unprecedented levels of capital investment in Transmission facilities, to become compliant with a proposed standard without any evidence that such increased requirements are justified. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements justify the huge expenditures certain under the proposed standard. A clear understanding of the reliability benefits and economic costs to customers is critical prior to final action on the proposed standard. While tightening standards will result in a more secure system, overbuilding the system at a significant cost to withstand more severe but less likely contingencies may not be in the public interest. Additionally, it is unclear whether the propose standard is in conflict with section 215 of the Energy Policy Act of 2005. 5. System Adjustment Clarification The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed such as committing units, de-committing units, firm and non-firm use, etc. would facilitate transparency and coordination between Transmission Planners. 6. Transmission Service Evaluation Another concern is that the proposed standard appears to be inconsistent with the current requirements for evaluating firm transmission service, generally based on an N-1 standard. To the extent this standard is adopted as proposed, the new standard would also need to be incorporated into the standards against which new transmission service is granted.

Response: 1. Much of the work that the commenter sites as additional is something that is required by the current approved standards. For example, Requirement R3.2 requires that the planner not just “outage” each power flow model element but reflect outage conditions that truly exists in the real world, e.g., a fault on a three terminal circuit should be modeled as three power flow elements being removed from the case to reflect actual operation. The concepts of “re-testing” and “committed” projects have been removed from the Corrective Action Plan so that only the value added concept of listing the actions necessary to achieve the desired level of system performance remains. Although sensitivity cases are now specifically required, they were considered by many utilities to determine the level of risk that remained after the addition of the proposed reinforcement projects.
2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard.
3. The SDT is unsure of the intent of the comment. While it is becoming increasingly difficult to build new Facilities, the fact is not in itself a valid reason for not complying with the performance requirements of this standard. The responsible entity is required to annually assess the compliance with the performance requirements and to have a Corrective Action Plan when the assessment indicates an inability to meet the

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Commenter	**Yes**	**No**	**Comment**
performance requirements. A Corrective Action Plan does not necessarily result in building new Facilities. If it is impossible to correct the failure then a mitigation plan should be submitted for approval. 4. The SDT shares your concern on the benefits and cost to meet the proposed increase in some requirements. The SDT and a large number of commenters felt that the proposed changes in requirements were reasonable and will help improve reliability. The SDT is including in the next draft, a schedule for compliance in the Implementation Plan which should give some time for entities to become compliant with the new requirements. The TPL standard is not a standard "to build"; it is a standard to plan for System reliability. The individual entities have the option of deciding how best to meet the growing load and associated reliability needs. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The provisions for an entity to grant Transmission service in the US is part of the entity's OATT and is beyond the scope of this standard.			
Exelon	☑		1. There should be more specific requirements for the long-range studies. The P requirements should be run on the long range case but corrective action plans need only be proposed and not committed. 2. R3.3.2.1 appears to require consequential load loss identification including peak demand and duration. however there is no requirement addressing the use of this information. Why is this required? 3. R3.3.3 should be clarified. It is our interpretation that not each of the P contingencies be studied if sufficient rationale is provided to determine the most critical. It would seem that each of the planning category events would need to be addressed. 4. What is the expectation regarding sensitivity analysis in R2.1.3 and R.2.4.3 if there are no performance requirements defined? 5. It should be clear in the performance tables that the 'event column' contingencies are logically 'or' events.
Response: 1. The performance requirements apply to both the "near-term" and the "long-term"assessments. Compliance with the performance requirements should be documented through assessments and a Corrective Action Plan. The SDT has modified the requirements in the new draft to remove the phrase "committed projects." 2. The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 3. Requirement R3.3.3 requires evaluation of only those Planning Events (involving multiple Contingencies) that are expected to produce more severe System impacts. Requirement R3.3.3 also requires that the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. 4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements			

<table>
<tr><th colspan="4">Q43</th></tr>
<tr><th>Commenter</th><th>Yes</th><th>No</th><th>Comment</th></tr>
<tr><td colspan="4">R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

5. The SDT has made changes to clarify the table.</td></tr>
<tr><td>FirstEnergy</td><td>☑</td><td></td><td>1. - R1. Load flow model submittal is redundant with various MOD standards and should not be required by this standard. To the extent any new requirements are introduced, we suggest that existing MOD standards be revised or new MOD standards be created as needed.

2. - R2 Organization of this requirement could be improved by grouping by Near Term and Long Term and then by steady state, short circuit, and stability requirements.

3. - R2.1 Too many annual studies are being required by this standard for the Near Term. We suggest limiting the current study year requirement be limited to one Near Term study. As written, it appears that this requirement forces a study for each of the 5 years, however the requirement should to be able to assess the entire 5 year period but not study each year.

4. - R2.1.1: As written, 2 studies are needed to meet this Near Term assessment requirement. It should be left up to the TO to determine the appropriate year in the short and long term periods. It's particularly odd given the fact that the TO could select year six for the Long Term study which would end up giving him back to back year 5 and 6 studies. The requirement should be to study one year in</td></tr>
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Commenter	**Yes**	**No**	**Comment**
			the 1 to 5 and one year in the 6 to 10 year periods. 5. - R2.2: This wording is very confusing. We are assuming that it means that you must continuously have to have a study that is less than one year old for the year 6 to 10 period. If so, wording needs to be clarified. 6. - R2.4.1: The idea of modeling induction motor loads is good in concept, be we question the practicality for an auditor to enforce. To date, a definitive way to model induction motor load does not exist. For example, what is the right mix for percent of load to be motor load or percent of large vs small induction motors. 7. - R2.6.1: Unless "material change" is specifically defined, the requirement is ambiquous and difficult to enforce consistently. What constitutes a "topology" change? 8. - R2.6.2: Same comment as R2.6.1 above, material change needs to be defined. 9. - R2.6.3. Same comment as R2.6.1 above, material change needs to be defined. 10. - R.2.7.1.1: We don't think it is reasonable nor necessary for the TO to provide an initiation date. No one should care when it was initiated as long as it is in service by the time it is needed. 11. - R2.7.1.2. Requiring an in-service year for the long-term may not be feasible for the initial study assessment. Based on the number of issues that could occur in the long-term horizon it may take a TP another 6 months to a year of more detailed area studies study to find the optimal solution(s) to resolve multiple system deficiences. In the long-term, only a list of SOLs problems along with year problem is initially anticipated should be required. 12. - R3.2.1: We suggest the following rewording "R3.2.1. Studies shall include the minimum steady state voltage limitations for all generators, and generators shall be simulated to trip for voltage below the minimum steady state limitation." 13. - R3.2.2: This is unnecessary in this standard. This is already addressed in the FAC standards dealing with equipment rating. Additionally, the proposed PRC-023 relay loadability standard addresses this concern. Alternatively, reword the requirement to say "if a relay is expected to trip because of an overload then the resulting facility shall be simulated in addition to the initiating event". 14. - R3.3.3. How do you know which events beyond single contingencies result in producing "more

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Commenter	**Yes**	**No**	**Comment**
			severe" impacts without running all? Either you test or you don't. We suggest some type of cyclical expectation for testing each of the less probable Planning Events, i.e. every three years each must be covered etc.the most critical 15. - R3.4 Same comment as R3.3.3, you need to test each to understand which produces the most severe impact. We suggest some type of cyclical expectation for testing each of the Extreme Events. The frequency of testing should be less often that the items covered in R3.3.3. It appears the only expectation is to consider some type of change to reduce or mitigate potential Cascade for Extreme Events. It should be clearly written that there in no mandatory expectation to remove the Cascade risk that may be associated with an Extreme Event. 16. - R4.5.1. Same comment as R3.3.3 (Steady-State) applies for this Stability requirement. 17. - R4.5.2. Same comment as R3.4 (Steady-State) applies for this Stability requirement. 18. - R4.6.1. We agree with the requirement but the SDT should assure consistency with data submittal requirements in the MOD standards. PERFORMANCE TABLES - General 19. In general, we feel the tables are overly complicated and difficult to follow. We suggest the SDT give consideration to merging the proposed tables back together to a single performance table. We also question why the team chose to leave the NERC A, B, C, D concept. The concept of Planning Events could reflect that NERC A, B & C categories must be met for Planning Events and that Category D are Extreme Events. Drastic deviation from the historical NERC performance classifications will require significant re-write of existing TP planning criteria documentation. 20. 300kV Level - It is confusing how the 300kV level requirements are placed within the tables. We suggest separate columns for performance requirements for 300kV and higher and below 300kV. This way, the same Planning Event could easily be reference on the same line and the expectations for each system level could be more readily determined. TABLE 1 - Steady-State Performance Table 21. We suggest that the "Initial Condition" column that is included in Table 2 - Stability Performance Table - also be added to Table 1. This would allow each to have the same look and feel, and would cut down on the lengthy wording such as: "Loss of a generator followed by System adjustment followed by loss of a generator" 22. Bullet 1 - "Equipment Ratings should not be exceeded." It is not clear which equipment rating

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Commenter	**Yes**	**No**	**Comment**
			would be the applicable rating. 23. Bullet 3 - "Voltage instability, cascading outages and uncontrolled islanding shall not occur". These terms require a definition to ensure consistent interpretation and application from an auditor. 24. It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 25. Why are non-bus tie breakers treated separate from other breakers? 26: P2: Why is a stuck breaker listed as a single contingency? 27. P8: What about a transformer followed by a line outage? Why not just simply list the components and say any combination of the two. 28. P9: "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? Extreme Event Descriptions: 29) For item 1, it's understood that for the N-2 items listed, the "extreme" aspect is that the second event occurs without system adjustment. However, we question whether a two generators simultaneously out should be considered an extreme condition. 30) We agree with the items listed in item 2 as they line-up well with the prior category D events from the existing TPL standards performance table. 31) Many of the classifications listed in item 3 are subjective and can not be tested. We propose that these items should not be requirements. TABLE 2 - Stability Performance Table 32. With regard to Table 2, much of the proposed testing required for stability are not necessary from a reliability standpoint. Some test items are included that are not, at least in the eastern interconnection, going to impact stability any worse than the relatively simpler requirements of the present standards. By testing single phase local faults in conjunction with a stuck breaker and remote faults with back up clearing for each line emanating from a power plant, you'll cover 99% of your stability issues. Also, this table does not adress relay scheme failures (back up clearing) that were

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Commenter	**Yes**	**No**	**Comment**
			covered in the present standard and which can have a significant impact on the stability of a unit/system. 33. Under the "Event Column", it is inconvenient to need to look back and forth on the table to reference other events, the items should be written in full text. For example, under P4 it is indicated that the "Initial Condition" is a single generator out and the "Event Column" indicates apply "P1.2 Contingency, P1.3 Contingency, etc." These items should be written out so that the user of the Table does not need to flip back and forth to see what the referenced contingencies entail. 34. Regarding P1, why require dynamic analysis for an unexpected loss of the listed equipment without a fault? The fault iniated outage will always be worse. 35. As stated above for Table 1, It is not clear why stuck breaker items are distinguished from an internal breaker fault. Each will create the same resulting system condition. 36. P5, P8, P9: The analysis suggested to run these multiple contingencies in dynamics would be extremely time consuming and produce little value. We suggest that the steady-state anlysis be used to screen those contingencies which show the potential to cause system cascade and then run dynamic analysis on those items. 37. As stated for Table 1 above, "Loss of a transformer followed by a System adjustment with a spare transformer available followed by the loss of another transformer." It is not clear why this is needed? Wouldn't the spare be a possible mitigation of the initial contingency? 38. In the Notes section shown under Table 2, for item "ii", we are not sure this could be accomplished as our relay models are not reflected in our data set used for dynamics simulation analysis. Two separate and unique software tools house the data and we believe this to be common among most companies.
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. Changing the order or sequence of the specific requirements has been discussed by the SDT but the decision was to retain the current sequence to avoid more confusion among the commenters. The benefit of changing the sequence did not outweigh the benefit of continuity at this point. The commenter is welcome to make a specific proposal for change in the next round of comments. 3. Requirement R2.1 does not require a study for each of the five years. The Planning Assessment shall cover the five year period. Requirements R2.1.1, R2.1.2, and R2.1.3 cover peak loading, off-peak loading, and sensitivities. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that			

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Commenter	**Yes**	**No**	**Comment**

in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required.

Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "...supplemented with qualified past studies..." If you have past studies which are applicable, the standard allows for such.

4. The SDT feels that the requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that in Requirement R2.1.1 the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required.

Requirement R2 includes a statement which states that "Planning Assessment shall use current or past studies." R2.1 allows for the Planning Assessment to be "...supplemented with qualified past studies..." If you have past studies which are applicable, the standard allows for such.

5. The intent of Requirement R2.2 is to study one year in the five year period each year. The timing of annual planning studies may mean that the most recent study is slightly over one year old in some years. Over time, the entity should have a portfolio of studies for the long term period as the basis to confirm the assessment of the period.

6. The SDT has softened the wording of Requirement R2.4.1 to address this issue.

R2.4.1. System peak Load for one of the five years. For peak System Load levels, ~~the~~a Load model shall ~~include the dynamic effects~~ be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads.

7, 8, and 9. The SDT agrees this is difficult and has modified the requirement to add some clarity. Most of the studies now have a backstop age of five years where they are no longer useable.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.

R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

10. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT

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Commenter	**Yes**	**No**	**Comment**

continues to believe that providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.

11. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.

12. Requirement R3.2.1 was meant to allow the Planning Coordinator and the Transmission Planner the discretion on the treatment of the generators that may exceed their maximum or minimum voltage limits.

13. The SDT has received numerous comments in support of these requirements. Requirement R3.2.2 is included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to be clear that this factor must be taken into account in the planning studies. In addition, Requirement R.3.2.2 only requires the studies to consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. The SDT has not made changes in response to this comment.

14, 15, 16, and 17. The SDT believes it is appropriate for the Transmission Provider/Planning Coordinator to decide how to determine the events that result in the "more severe" impacts.

The SDT believes that the standard as written is clear and does not indicate a "mandatory expectation to remove the Cascade risk" for Extreme Events. For example, Requirement R3.3.1 indicates that performance criteria shall be met only for System normal conditions and for Planning Events in Table 1. Requirement R3.3.1 does not include the requirement that the performance criteria be met for Extreme Events.

18. The SDT has added requirements R9 through R13.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.

R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information.

R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each

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Commenter	Yes	No	Comment
year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 19 and 20. The majority of commenters support the development of the two tables as opposed to the single table in the existing TPL standards. Further, the SDT believes that the two tables provide the ability to clarify issues associated with Stability performance and evaluation requirements versus steady-state performance and evaluation requirements. These issues were expressed by commenters during the development of the SAR that initiated the re-write of the TPL standards. By the same token, comments were expressed during the development of the SAR about the need to consider significantly changing the classification of outages to these categories and even to consider eliminating the categories. The SDT took the approach of eliminating the categories in order to concentrate on defining the performance requirements individually for each event as appropriate. The SDT does not see a need at this time to revert to the previous classifications. The SDT has made changes to the tables to clarify the performance and evaluation requirements as the SDT agrees with the commenter that further clarification from the standard issued in the first comment period was required. The SDT agrees with the commenter concerning the need for clarification of the 300 kV performance requirements and, as a result, made changes to the standard intended to accomplish this purpose. 21. The SDT has implemented the suggestion to add an initial condition column to Table 1. 22. The SDT notes that Equipment Ratings are covered in the FAC standards and are set by the Transmission Owner. The SDT does not see the need to add any further requirements with regard to Equipment Ratings. 23. Definitions for cascading and stability are included in the NERC Glossary. Further uncontrolled islanding, while not defined, is a common term that is well understood. The SDT does not propose to improve the definitions for Cascading and Stability or propose a new definition for cascading outages and uncontrolled islanding. The SDT believes that while it may be helpful to either develop a voltage instability definition or else specify performance requirements for voltage instability, there are not generally accepted performance requirements for voltage instability across NERC making it difficult for the SDT to write a voltage instability performance requirement at this time. For example, it has been found that an acceptable margin for voltage Stability varies bus to bus and therefore, is not suitable for a general instability requirement on a PV curve or alternative. There are a number of IEEE papers (e.g., P. Kundur, J. Paserba, V. Ajjarapu, G. Anderson, A. Bose, C. Canizares, N. Hatziargyriou, D. Hill, A. Stankovic, C. Taylor, T. V. Custem, V. Vittal, “Definition and Classification of Power System Stability”, IEEE Transactions on Power Systems, vol. 19, no. 2, pp. 1387 – 1401, May 2004) that provide descriptions of voltage instability. It is important to understand what events are being modeled even when conducting steady state studies so as to ensure that studies are being conducted recognizing the FERC indicated in paragraph 1707 of Order No. 693 that planning assessment “faithfully duplicate what will happen in the actual power system and not a generic listing of outages.” As a result, the SDT is not proposing to make changes to the standard in response to this comment. 24. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 25. The reason for separate treatment of Non-Bus-tie Breaker and Bus-tie Breaker is that there are different System consequences for the 2. 26. The SDT agrees that a stuck breaker is not a single Contingency. It requires a fault-initiated Contingency followed by the failure of the breaker or the System Protection to operate properly. As a result, the stuck breaker is a lower probability Contingency. The SDT has changed the identification of the outage in the table. 27. The SDT agrees with this suggestion and has made the change to the table. 28. P9.6 was an attempt to include outages involving long lead time equipment considering spare equipment strategies in the table as			

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Commenter	**Yes**	**No**	**Comment**
directed by the FERC in Order No. 693. The SDT has deleted P9.6 and included this consideration in Requirement R11 of the second draft of the standard to address this issue. 29. Whether two generators out without System adjustment in between is an event which severely stresses the System would depend on the individual System under study; the SDT believes it is appropriate to not include this as a Planning Event and therefore has not revised the table as suggested. 30. Thanks for the support. 31. With regard to the comments about the Extreme Events in Item 3, the SDT notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events and Item 3 is consistent with paragraph 1834 in the FERC order. See the response to BPA 7 for more details. Further, the SDT notes that these events dramatically impact the reliability of the interconnected network and are logical extreme events for which the probability and consequences should be evaluated when considering ways to make the transmission system more robust with operating procedures and/or system improvements that are reasonable in cost in comparison to the probability and consequences of the extreme event. The SDT did not change the standard with regard to these comments about Extreme Events in Item 3. 32. The SDT believes that all Stability requirements are necessary for reliability based on an understanding of current practices within North America. Protection systems will be addressed in subsequent versions. 33. The SDT has completely re-formatted the tables due to industry comments. 34. The SDT agrees and has made the change to the table. 35. The SDT feels that the resulting conditions are not the same. Stuck breaker is described in the notes in the tables. An internal fault is a single Contingency but a stuck breaker is not. 36. The SDT believes that Requirement R5.5.1 provides the distinction you are looking for. 37. Spare terminology has been deleted. 38. The intent of the note is the system must meet performance and that the loss of any generator is not greater than your Contingency reserve. You can simulate relay models using other techniques.			
FPL	☑		1. General Comment: NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order as well as created unnecessary confusion. FPL believes that the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard was not a specific requirement by FERC Order 693 and may not have been a good decision by the STD, therefore it should be reconsidered after reviewing all of the comments. At a minimun, the team should somehow clearly demonstrate changes in the standard's wording and required performance levels as compared to the existing standards. The new proposed draft of TPL-001 creates unnecessary confusion and interpretation of new ambiguous language, which is inconsistant with the stated objectives, instead of providing clarity to the standards. As an example of how to provide additional clarity, the existing standards have unnecessary redundancy in the tables, for example, it would have been nice to clean up (clarify) the tables such that the table for TPL-001 would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on.

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Commenter	Yes	No	Comment
			2. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unjustified major capital expenditures and/or reductions in ATC. This also could have an adverse impact on commercial transactions. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system after Planning Events. The benefits from the additional performance requirements have not been identified in the proposed standard. Is there a planned phased in approachto move from the existing standard to the new proposed standards. If so, what is it? 3. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness. Specific comments on the Draft Standard Performance Criteria 4. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of service is created,

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Commenter	**Yes**	**No**	**Comment**
			which is unjustified. Comments on New Performance Tables: 5. The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 6. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 7. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 8. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice will apparently be disallowed. 9. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. The fault with protection element failure categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 10. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted nor have they been justified. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements.

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Commenter	**Yes**	**No**	**Comment**
			DC Line Performance Requirement 11. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 12. Models cannot discern the difference between a “committed” project, and a “proposed” project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a “project initiation date” is ambiguous. What will constitute “project initiation” …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. “Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements.” In addition to the concerns mentioned above, how are delays in meeting project in-service dates, which are not in the direct control of the Transmission Owner, caused by siting and Right of Way difficulties (public outcry, exercising eminent domain, court process, etc) addressed? The standard needs to have provisions to recognize these types of issues allowing a Transmission Owner to be compliant as long as he is using due diligence to overcome these types of delays. Analysis of Relay Protection Failures: 13. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must

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Commenter	**Yes**	**No**	**Comment**
			usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to address relay failure verses breaker failure. Load Modeling Requirements: 14. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. 15. R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE’s may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. 16. R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate fot the TPL standarsds. 17. R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads.

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Commenter	**Yes**	**No**	**Comment**
			18. Specific types of load models should not be required in this standard. 19. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 20. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and not pursue the proposed new standard any further. This would bring a much needed part of the Reliability Standards into the framework of mandatory enforcement and provide guidance on this longer term effort to improve the TPL standards.
Response: 1. The SDT must not only consider directives made in the FERC Orders, but it must also consider the direction given in the two associated SARs. Much of the wording and format in the current standards is repetitive. They all share the same performance table. Historically many have commented that because of the duplication in wording and format that the four should be merged together so that consistency would follow. It would also be easier to find and see the differences for each level of contingency. The SDT will continue to minimize repetitive language, simplify tables, minimize the number of notes, etc. Commenters in general have supported the concept of merging the four standards together. In addition, Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition, this order, in conjuction with 890, enurmerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome. 2. The SDT understands that there are extended transition issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an implementation plan to accommodate such issues. The plan will be included in the third posting of the standard. 3. The requirement concerning Consequential Load Loss is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. In regard to your comment regarding the general use of footnotes, the SDT agrees that notes can add clarity and we have included footnotes where useful in the newly formatted tables. 4. The SDT agrees with the comment that the initial conditions must be clarified in Table 1. Therefore, the SDT has made changes to add an initial condition column to Table 1. The SDT agrees that the System must remain secure after an event and therefore has clarified the standard by adding words to cover this requirement. Further, the SDT agrees that the overlapping single Contingencies in C3 or the multiple circuit tower Contingency of C5 in the existing TPL			

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Commenter	Yes	No	Comment
standards are much lower probability but given that the performance requirements are only raised on these events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 5. The SDT agrees with the comment and believes that this is consistent with FERC Order No. 693. 6. The SDT agrees that C1 and C2 in the existing TPL standards are much lower probability but given that the performance requirements are only raised on C1 and C2 events for facilities above 300 kV, the SDT does not believe that the proposed changes are unreasonable especially since the changes are consistent with FERC Order No. 693. Please see the SDT responses to Question 22 for more details. 7. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. 8. The SDT has referenced Facility Ratings in general terms in Requirements R3.3.2.3 and R3.6.1 to provide flexibility with time based ratings. 9. The SDT has reviewed and revised Extreme Events in Tables 1 & 2. 10. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. 11. As a controllable element, a DC terminal can carry more load than it might otherwise based on an impedance split in an all AC System. With most DC providing asynchronous DC ties, the SDT has elected to allow interruption of service. 12. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2			

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Commenter	**Yes**	**No**	**Comment**
through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions". The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities however the region defines "initiation". **R2.7.1**. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 13. Protection system failures are being studied and will be covered in a future version. 14. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 15. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. 16. The SDT has revised this requirement based on industry comments to clarify the intent that Load data be based on expected or historical System performance. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 17 & 18. The SDT believes that the dynamic effects of induction motors must be considered. The standard does not specify the details of how to model induction motors. Therefore, the SDT believes the standard includes the necessary requirement without being overly prescriptive. 19. Your reference to FAC-002 only addresses the study of a specific request for Interconnection. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. 20. The SDT believes that the present course of drafting the four standards as one standard with a revised table of "Contingencies" is the best solution to addressing all FERC directives, following the SARs, considering past comments and providing a single standard outlining the fundamental planning analysis.			
FRCC	☑		General Comment: 1. The SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will require unnecessary major capital expenditures and/or reductions in ATC which will have an

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Commenter	**Yes**	**No**	**Comment**
			adverse impact on commerce. Neither of these outcomes is desirable. Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed. (Interruption of Firm Transfer) Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a

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			very significant change for some utilities and this limited exception should be maintained. Footnote (b) was worked on extensive and achieved industry consensus at one time defining the maximum amount of load that could be shed at 100 MW. Footnote (c) which permits load shedding and curtailment of firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. It is not clear what is meant by the phrase "Equipment Ratings" found in the performance requirements of Table 1. Utilities have different equipment ratings such as normal, long term, short term and emergency ratings. It is not clear that these type of ratings will be permitted in the proposed standard. 6. Several new Category D "extreme events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (3) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required stability studies. Analysis of Relay Protection Failures: 7. The fault with protection element failures have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing standards is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard does not require the analysis of any protection failure. This draft of the TPL standard ignores studies required for analysis of relay protection failures. There is a widespread misconception that studying breaker failure scenarios covers for relay protection failures. This is a false assumption. Typical delayed clearing for a stuck breaker is in the order of 8 to 20 cycles. This is accomplished by the local relay system sensing the stuck breaker and tripping the adjacent elements. However in the case of a protective relay failure the fault must usually be cleared remotely by tripping all lines connected to the station. Typical delays for a relay failure can easily be greater than 30 cycles. Where as breaker failure action just trips a couple of adjoining elements and leaves the rest of the station intact. A typical example of this difference is to assume a bus fault. For breaker failure, all bus breakers except the stuck one would trip. The breaker failure relay scheme then would time out and trip the adjoining breaker and the remote end of the adjoining line would trip. This could all happen in less than 20 cycles. Now consider a bus fault with the differential relay failed. The local relays don't sense the fault because they have failed, nor does the local breaker failure scheme activate because no local detection has occurred. The only way to clear this fault is to trip all lines from the remote terminals. This may take 30 cycles or more. With breaker failure, the bus and one line trips in about 20 cycles. With relay failure, all lines trip remotely isolating the substation in about 30 cycles. Both scenarios must be studied with relay failure being the worse case. Generally, different solutions are required to

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			address relay failure verses breaker failure. 300 kV Threshold Performance Level 8. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Load Modeling Requirements: 9. The proposed TPL Standard contains numerous references to load modeling. These modeling requirements should be addressed in the MOD Standards. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of Recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. * R1.1.1 Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some LSE's may have great difficulties in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. * R1.2. Load models with supporting rationale that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 10. * R2.4.1. System peak Load for one of the five years. For peak System Load levels, the Load model shall include the dynamic effects of induction motor Loads. Prescribing specific types of load models in this standard is not appropriate because system topology and load make up may be unique from area to area. 11. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. These performance criteria are better suited in the FAC

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			Standards since evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. 12. Table 2 Angular Stability Notes: The requirement of generation loss not exceeding BA spinning reserve requirement (1.a.ii.) is an unjustified increase in required performance level from the existing TPL Standard which require the grid response to be stable and within applicable ratings. The portion of the notes requiring generator out-of-step protection are inappropriate and unwarranted. First, the simulation result may show the generator being tripped by backup distance or loss of field protection which may be acceptable to the generator owner. Second, the requirement for impedance swings not causing other transmission elements to trip is inappropriate and in conflict with manufacturer recommendations and prevailing practice for generator out of step protection. Most generator out of step relays are set to trip on the "way out" so as to limit phase angle difference across the opening contacts. With this practice, one can not prevent transmission line tripping due to zone 1 pickup without installing out of step blocking should the swing impedance passes through zone 1 relay. Out of step blocking of zone 1 relays is a bad idea as it opens the door to prolonged asynchronous connection of generators. 13. Circuit Breaker Contingencies: The proposed TPL standard separates circuit breaker related contingencies based on the intended use of the circuit breaker. If the circuit breaker is used to connect busses together (i.e. bus tie breaker) a lower level of performance is required than for other uses and configurations. The existing TPL standards have the contingency events and required level of performance appropriately ordered based on the probability of occurrence. We are not aware of different failure rates for bus ties breakers as opposed to the general circuit breaker population. The proposed standard requires an unjustified higher level of performance for non bus tie breakers and would encourage the use of low cost switching station arrangements such as single breaker/single bus which are less reliable. 14. Need to clarify the performance requirements that apply to sensitivity studies. These requirements should not be the same. 15. A.3. - Suggest replacing the word "probable" with "credible" for consistency with the white paper from the Operating Limit Definitions Task Force. 16. R2.1 - It is not clear how the requirement to address all 5 years can be accomplished when the annual studies do not require all 5 years to be studied. Is the planner expected to study the

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			other years also, but that the required set of cases does not link to each of the 5 years? 17. R2.2.1 - This requirement creates compliance concerns. Therefore, it is suggested that the SDT clarify that the Long Term Assessment is not required beyond 10 years. 18. R2.7.3 - The term "proposed" may not be a good choice here ... especially since that's not a term used in other reliability assessments .... should another term be chosen or perhaps this definition could be matched up with work being done now on classification of resources for RAS. Steady State Performance Table: 19. P1 - If the transmission line outaged is the facility defined by contract as being the only contract path for the firm transfer, then the firm transfer will be interrupted. P1 should be clarified that this is acceptable. 20. P3 - Are these elements meant to be combined into a multiple contingency or considered separately (since they are listed with commas)? Or is this meant to be one of the 3 elements listed first AND the stuck breaker? Not clear the way this is worded. Or maybe the structure needs to be different in the sentence (like bullets for the first 3 that would make the "and" stick out more). 21. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1 the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in that Order. The proposed draft standard is a large change in the magnitude of the performance requirements from the exiting TPL Standards. The SDT needs to consider how this proposed standard will be implemented in this new mandatory compliance environment and ensure that reasonable compliance measures can be developed from the proposed standard.
Response: 1. The SDT recognizes that it has it has raised the bar on performance in some areas. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. FERC Order 693 clearly states the FERC position on Non-Consequential Load loss. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance. 2. An Initial Conditions column has been added to the tables. 3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group. 4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision. 5. Equipment Ratings is a defined term in the NERC Glossary. 6. The SDT was responding to FERC Order 693 in the details for Extreme Events.			

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7. The SDT is still working on the Protection System elements of the standard and will provide more detail in a future revision.
8. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria.
9. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13.
10. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models.
11. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions.
12. The note on spinning reserve has been corrected. The existing standard does not define what it means for the grid response to be stable. The SDT has attempted to do that with the footnote you referenced. The SDT believes that an excessive amount of generation pulling out of synchronism and tripping is not a stable grid response. Therefore, we have limited the amount which can trip to the amount of the Contingency reserve of the Balancing Authority. If a generator pulls out of synchronism, the SDT believes there should be some means to trip the generator from the grid. Otherwise, the generator could be damaged and the quality of power on the grid suffers. The footnote has been modified to require that the generator must have "out-of-step protection or some other means to trip the generator". The requirement for impedance swings to not cause the tripping of other Transmission elements is most appropriate. A stable response of the grid would not include losing additional Transmission elements. Out of step blocking on lines is not allowed as a solution. The requirement is for the impedance swing not to pass through relay characteristics which would result in tripping Transmission elements. This requires the system to be improved so that the impedance swings do not go out on the Transmission System.
13. Based on the available outage data, the SDT has decided that bus tie breakers are less likely to be exposed to stuck breaker opportunities
14. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the System the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

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R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied. 15. The SDT feels that 'probable' is a better choice of words here and the majority of commenters have supported the SDT decision on how the purpose is stated 16. The SDT believes that a planner will be able to aggregate current and past studies in a portfolio or archive that will fulfill the requirement. 17. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon". Paragraph 1692 of order 693 "directs the ERO to consider integrating Reliability Standards TPL-001-0 through TPL-004-0 into a single Reliability Standard through the Reliability Standards development process". In addition this order, in conjuction with 890, enumerates attributes of planning standards that the FERC feels should be incorporated into the consolidated standard. SDT believes that the first draft of the standard is consistent with orders 693 and 890 without being unduly burdensome. The SDT is cognizant that reasonal compliance measures and an achievable implemetation plan need to be developed as part of the standard development process. 18. The indicated language has been deleted from the second revision. 19. P1 - If service to Load by contract can be interrupted for defined conditions, then the SDT does not view this as firm. 20. The SDT has re-formatted the tables to clear up any confusion on this item. 21. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible.			
Georgia Transm.	☑		R1.4: The planning assessment is to identify the needs of the BES. A spare equipment strategy should support the needs of the BES, not vice versa. Long-term outages need to be defined. R2.2.1 Not clear on the purpose of this requirement. Is the concern that the Planner perform a ten year analysis even when the in - service years are outside of the current ten-year planning horizon? The extension period should be defined. R3.2 Current models do not have the capability of performing the assessments necessary to meet this requirement.
Response: 1. The SDT has revised this requirement based on industry comments to clarify intent and to be responsive to FERC Order 693, paragraph 1725. 2. The SDT believes that the requirement as written is clear that studies longer than 10 years are only required if the known lead time of critical projects is longer than 10 years. The standard as written does not mandate a study longer than 10 years out but recognizes that a 15 year out study conducted to adress anticipated long lead time projects can be used to fufill the requirement of "Long-Term Planning Horizon".			

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3. The SDT feels strongly that the assessment should be based on study of the System as it is expected to perform. The requirement that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention" is consistent with that philosophy. A Contingency modeling methodology that reflects how real Systems would operate will need to be constructed if it doesn't already exist.			
IESO	☑		(1) Pertaining to Q1 to Q11: we do not see the need to define this many terms for this standard. Many of the terms are easily understood and have been used in transmission planning for years that the majority of planners in the industry know what they mean. For example: base case, extreme contingencies (these are in fact listed in the table), planning assessment, planning event, etc. Furthermore, the terms plant stability and system stability are also well understood to mean "machine synchronism" and "system oscillation/damping". Among the proposed definitions, only the following terms need to be defined to add clarity: a. Consequential (and non-consequential) loss of load b. Long-term vs near-term (suggest to change it to short-term) planning horizons (2) We do not see the need to use the term RAS (Remedial Action Scheme). The term SPS (Special Protection System) is common used in the industry to generally mean any protection scheme that is designed to initiate actions to control flows, voltage, generation runback or high speed rejection, switching of shunt devices, cross-tripping in response to some pre-determined parameters such as loss of a circuit or some threshold voltage or line flow level. Introducing the term RAS would be confusing to suggest that they do not equate to or are not a part of the SPS. (3) We interpret the requirement stipulated in R1.1.1 is intended to enable more accurate simulations of load response - both in steady state and dynamic analyses. However, we do not support having this level of granularity (eg: industrial, commercial, residential etc.) stipulated in a planning assessment standard as similar requirements already exist in several MOD standards that deal with forecasted load and modeling. We suggest the mix of load detailed requirements be addressed in the latter set of standards. Similarly, R1.2 is best addressed in the MOD standards. Specific to R1.2, we do not agree with the requirement to provide supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. Load forecast data already provides projected mix of real and reactive demands and type of load. (4) R1.4 and R2.1.3 require outages be considered in the planning process. We suggest the SDT clearly stipulate that only known planned long term outages (with a minimum duration to be defined) need to be considered. This suggests is made on the basis that:

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			- Only known outages should be modeled. The need to model unknown outages would render study scope to be too wide to manage - Only planned outages should be modeled for the same reason. - Only known planned outages > a certain period should be modeled since it would be unrealistic and unmanageable to model and propose planning solutions to system constraints that appear to last less than, say, 2 weeks. As a general practice, many planners apply a 4 week period as the minimum for inclusion in planning assessment. Without narrowing the scope, planning assessment will be an enormous task and difficult to manage.
Response: 1. The SDT deleted the Base Case definition in response to various comments. However, few if any other commenters suggested deleting the other terms proposed in this comment and several suggestions were received from various commenters to include additional definitions. Furthermore, various comments indicated lack of a consensus understanding of the Stability terms, prompting the SDT to retain and clarify the initially proposed definitions. 2. RAS and SPS are interchangeable terms as per the NERC Glossary. 3. The SDT believes that models must reflect the expected Load mix of industrial, commercial and residential Loads to correctly reflect the behavior of the System. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 4. The SDT intent was for the planner to model known planned outages. Sensitivities may be needed to confirm how much affect the duration of the known outage may have on the assessment. Requirement R1.4 which applies to the whole standard calls for "Known planned outages…"			
ISO/RTO	☑		
Response: Thank you.			
ITC	☑		1. A modeling issue that we would like to see standardized is the modeling of generation resources when the load exceeds or is very near the installed reserve level (low generation reserve margin). This would occur in future years when new resources are unknown or not announced yet. It is a concern of ours because we are an independent transmission company and are not always apprised of new resources. We also have a concern with some models which "assume" where new generation would be located or fake generation has been added to meet the load requirements. This can produce distorted transmission assessments because the generation location assumption is not firm. We would prefer to see generation scaling, or an assumption that the power will be imported or a combination of scaling and imports. Assuming 100% generator availability is also not a good assumption just to balance load and generation. Other modeling issues:

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			2. Should not rely on a single generator being dispatched (redispatched) to solve a problem. 2. Using a single generator for redispatch should not be an acceptable corrective action (i.e. rely on a generator that might not be there or may take an extended period to start up). 3. Sensitivities for both the planning horizons should consider load forecast error and variability. You shouldn't just stick with one assumption, such as a 50/50 probability of occurrence. The system needs to be able to operate to loads exceeding 50/50 probability of occurance. 4. We would also like to see additional requirements be put on "corrective action" solutions to reliability violations resulting from planning assessments. Any corrective action should be restudied to insure that it does not cause other reliability problems for system conditions other than those for which the corrective action is intended to resolve. For example, if redispatch under a transmission outage condition is acceptable, it should not cause any additional reliability violations for the next contingency.
Response: 1. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. 2. NERC Standards are to specify the requirements, which must be met and not "how" they are met. Whether a single generator can be used in a Corrective Action Plan would depend on whether the resultant Transmission System can meet the other requirements of NERC Reliability Standards. Therefore, when a single generator is used in a Corrective Action Plan, the System must also demonstrate that it can meet System performance requirements for loss of that generator. If the generator is not yet on line, then additional sensitivity studies should be performed to cover the assumption that it may not be available. 3. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Due to the nature of future analysis, the SDT did not draft specific language to mandate Load growth be a sensitivity analysis for future assessments. Industry feedback is that future assessments already include a variation in projected Load growth. The standard does not preclude any entity from performing studies for any planning horizon that envolve a wide range of sensitivities. The specific requirement to perform re-test has been removed. 4. The SDT believes that as part of obtaining the appropriate corrective action, the solution is tested as part of the study to make sure it meets the performance requirements.			
JEA	☑		In reference to the use of Non-consequential load shedding under single contingency events: I do agree that long term plans should be implemented with the goal to eliminate non-consequential load shedding as a response to this failure mode. However, it may be more beneficial for investing in system improvements to reach this state of robustness where there may be a few years (or seasons) of potential exposure for utilizing non-consequential load shedding. This should be prudent utility practice as long as post-contingency response is executed within the time frame allowed by the

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Commenter	**Yes**	**No**	**Comment**
			facility emergency ratings and load shedding is limited to Transmission Provider's contracted or tarrif loads. For example, adding or upgrading transmission facilities into a load area where future generation additions are planned to be in-service within the short term horizon (mitigating thermal or voltage violations assessed under P1 and P4-1 through P4-4) would not be the best investment for the overall economic benefit of the bulk electric system.
Response: Draft 2 Changes for 300 kV and higher systems regarding N-1-1 conditions: Based on industry feedback the SDT has made changes in proposed Draft 2 requirements related to independent overlapping single Contingencies involving two non-generation Transmission Facilities operated at a voltage level above 300 kV. Draft 2 now permits the loss of Non-Consequential Load to meet the Transmission performance requirements for these types of events. Please refer to performance tables Planning Event P6. It is noted that in Draft 2 the SDT is still requiring more stringent performance requirements of the EHV Transmission for the less probable, but greater risk single Contingency events. Please refer to performance tables Planning Event P2 and note that bus section faults and internal breaker faults (non-Bus Tie) associated with above 300 kV Facilities are held to a higher performance standard than those operated at 300 kV or below.			
KCPL	☑		It is redundant to require provision of modeling data in this Standard. This is covered in Standards MOD 10, 12, 16-25.
Response: The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
LUS	☑		The Planning Authority/Transmission Planner should use valid acceptable assessments to plan their systems to operate and supply customer demand and Firm Transmission Service. If the Planning Authority/Transmission Planner determines other methods (such as operational guides) to resolve system overloads for "N-1 Contingency", the operational guides should be limited to only native network facilities that are in direct control and ownership of the Planning Authority/Transmission Planner. Operational guides should be considered only as short term solution to resolve the overloads and shall be used in all studies and approval for transmission service requests. If the operational guide do not completely resolve the overload or restricts access to transmission service, then the Planning Authority/Transmission Planner shall determine facilities to be constructed to resolve the overloaded or restricted facility.
Response: NERC Standards are to specify the requirements, which must be met and not "how" they are met. The draft standard does not preclude the use of operating solutions.			
LADWP	☑		This proposed standard is very tutorial in nature and far too prescriptive for a standard. A standard should be about what are the criteria and measurables, not about how to meet the criteria. This propsoed standard should also recognized that it is just a part of many standards being formulated by NERC, know its boundary as transmission planning standard, and not try to be an all

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Commenter	**Yes**	**No**	**Comment**
			encompassing standard for every facit of the power system. Do what we do best as transmission planner and not try to take over others like marketer, operator, generators, etc.
Response: The goal of the SDT is to provide more information but not be too prescriptive.			
LCRA	☑		1. The NERC PC and OC are currently working on a definiton that defines "adequate levels of reliability". The SDT should take this definition into consideration and ensure it is applied in the proposed NERC Std. revision. Along the same lines, if this has not been done yet, the SDT needs to consider the NERC "Reliability Criteria and Operating Limits Concepts" white paper and incorporate applicable elemetns of that white paper to the propsoed NERC Std. revision accordingly. It would not make sense for these (the propsoed NERC std. and the noted white paper to be inconsistent or at opposite ends in terms of what is expected of a reliability-based planned transmission system). other editorial comments: 2. R1. Delete one of the "each" 3. R1. Should state that data submittals should be "in accordance with regional procedures or process". This will eliminate the region getting data in all sorts of formats. 4. Table 1 - the allowance of loosing "consequential load" should be evaluated based on options to provide temporary emergency back-up support as well as size of load, for example. Structure failures can take an extended period of time to restore and can have significant impacts on a raial load that does not have remote or distribution back-up support. This performance requirment of transmisssion radial-supplied loads should be left to regions or to transmission owners/planners for their own areas based on specific area needs (type and size of load, back-up availbailiyt, etc.). 5. Table 1 - How does NERC define a "transmission circuit"? Does it include a sinlge transmission line as well as a double circuit transmission line? 6. Other than the probability of occurrence, what is the difference between a structure failure of a single circuit and a structure failure on a double circuit configuration? Why is a double circuit not considered a single contingency?
Response: 1. The SDT has reviewed the definition of adequate level of reliability and has included it in its deliberations. The SDT has reviewed the “Reliability Concepts” white paper and find that the document is largely consistent with the current standard as written by the SDT. One notable difference is that the white paper seems to indicate that the Transmission System is designed and operated so that cusomers should only be interrupted that are directly connected to the outaged element for events including Transmission line or transformer faults, breaker or switch failures, or generator trips. (See page 11 of the white paper.) If the SDT were to use this approach then SDT should not allow Non-Consequential Load Loss for P6.1 and P6.3, even though these breakers are below 300 kV.			

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Commenter	**Yes**	**No**	**Comment**
As indicated in the responses to other comments, the SDT has taken the position that the probability of the outage of one breaker is much lower than the probability of a single Transmission line outage. Therefore, the SDT has drafted the standard to permit loss of Non-Consequential firm Load or interruption of firm Transmission service for the loss of a lower voltage breaker. (The SDT does not permit the loss of Non-Consequential firm Load or interruption of firm Transmisssion service for the loss of a breaker above 300 kV.) The majority of the commenters in response to the first posting of the standard agreed with the SDT's approach in this regard. 2. Editorial change was made. 3. The SDT has revised this requirement based on industry comments to specify only that modeling data must be exchanged and allows entities to develop their own formats. It is beyond the scope of the standard to specify the process for data exchange. 4. The standard allows for loss of Consequential Load and does not address restoration requirements. 5. and 6. The Tables treat circuits differently if they share a common tower and they define the maximum length that a double circuit can still be treated as independent circuits as one mile.			
Manitoba Hydro	☑		1. MH would prefer that many of the categories in the existing Table 1 be retained. The SDT has resort the contingency buckets with no explanation as to how this was done. can the SDT provide statistical outage date to justify the changes. MH is not convinced the SDT has addressed the few confusioning issues in Table 1. 2. R1: MH does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 3. R1.4: requires planned outage data to be provided to planners. I do not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the impacts of an outage with system adjustment followed by testing for the next contingency. 4. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency in what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 5. R2.1: It is not necessary to assess all five years of the near term planning horizon – year one, three and five will be more than sufficient. What is the reliability benefit driving the SDT to mandate each of the first five years be assessed? 6. R2.1.2 and R2.4.2 -- It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control.

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Commenter	**Yes**	**No**	**Comment**
			7. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 8. R2.3: The short circuit study is a design issue that would more appropriately covered by a FAC standard. MH recommends it be removed from the Planning standard. 9. R2.6.1: Why would a past study be invalidated if there is a change in market structure? It would seem that the operation of any market would have to respect reliability criteria. 10. R.3.3.2.2: Curtailment of firm transfers is allowed as a system adjustment in the existing standard. This ability must be retained in the new standard. Curtailment of a firm transaction is not equivalent to curtailment of load, but is more comparable to runback/tripping of generators. Both are events that can be backed up by contingency reserves and do not result in consequential load loss. Disallowing firm transfer curtailment will result in numerous violations of the performance requirements and result in a requirement to build millions of dollars of transmission. MH can not accept a standard which mandates that firm transfers can not be curtialed following a contingency. 11. R3.3.3: If rationale for the contingencies selected for evaluation is available then this rationale will state why the selected contingencies are expected to be the most severe. The requirement does not need to state "and shall include an explanation of why the remaining Contingencies would produce less severe System resuts".This is redundant. 12. R3.4 and R4.5.2: Evaluating a change designed to mitigate the consequences of an exteme event can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose of this evaluation? 13. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. 14. R6: Requires distribution of results and “coordinating analysis of these results through an open and transparent process”. Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. There should be a requirement to conduct joint assessments on inter-regional transfer capability. The assessments should also be provided to the Regional Entities/NERC. Table 1 -Steady State Performance

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Commenter	**Yes**	**No**	**Comment**
			15. MH requests the SDT to provide rationale for how the planning events where resorted from the existing Table 1 Categories to the proposed Planned events. 16. Performance Requirements: As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? "Simulate Normal Clearing unless otherwise specified." should be deleted from this Steady State Performance table. 17. This table should have an Initial Condition column as well as an Event column, as in Table 2. The wording of event descriptions in Table 1 should follow the wording of similar event descriptions in Table 2. 18. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 19. Interruption of Firm Transfer Allowed: Interruption of firm transfer should be allowed following a single contingency – this is a change from the existing standard where system adjustment after a Cat B event could include reduction of firm transfer. Similar to generation tripping/runback, the loss of a firm transaction does not result in Consequential load loss as it is backed up by contingency reserve. 20. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 21. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 22. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 23. P9-2: A monopolar DC line loss may be covered in P4-2 (and no non-consequential load loss is allowed). Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line? 24. P9-3, P9-4 and P9-5: When the DC line loss is bipolar, the event should be moved to the extreme event category. Does loss of a monopolar DC line refer to loss of a single pole of a bipolar line or a bipolar dc line? Can the PC/TP choose between the loss of a monopolar DC line and the loss of a bipolar DC line?

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Commenter	**Yes**	**No**	**Comment**
			25. Exteme Events Evaluation Requirements 3: This should be removed as this is the Steady State Performance table. 26. Extreme Event Descriptions: How did the SDT determine what events should be classified as Extreme Events? Was statistical data analyzed? 27. Extreme Event 1: In the existing TPL standards, the simultaneous loss of two elements was considered a Cat C multiple element event. What is the SDT rational for the change? 28. Extreme Event 2c: Why is the loss of a single large load an Extreme Event? 29. Extreme Event 3f: This is a repeat of Extreme Event 3d. 30. Extreme Event 3g: What is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be desined to prevent multiple line loss due to icing? Table 2 - Stability Performance Table 31. Performance Requirements: The MRO adds 1/2 to 1 cycle to the Normal Clearing time during simluations as an additional safety margin. The SDT should consider enforcing this practice. 32. Event: What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? 33. P1: There should be a P1-4 event for a shunt device (ie. "4. A shunt device (including FACTS devices)"). 34. P6-2: What is the justification for classifing a bipolar DC line loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event. 35. P6-3: Why is a breaker internal fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements. 36. P9-1: Is there any justification for the selection of one mile? Would the fact that there is line shielding be justification for increasing this length? A more reasonable selection could be 5% of the length of the longer of the two circuits. 37. P9-3: This contingency should be classified as an Extreme Event since statistically, the outage

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Commenter	**Yes**	**No**	**Comment**
			duration of a dc circuit (assume you mean a bipole) is less than 2 hours for MH bipoles, so the probability of a second outage is very low. . 38. P9-6: Isn't this the same as P1-3? If the outaged tranformer is replaced by a spare transformer, this restores the system to a normal state prior to the event ("Apply a P1.3 Contingency."). What is the point? 39. Note 1.a.i.: Planning Event P3.2 does not exist. 40. Note 1.a.ii: This definition of angular stability should be deleted and the definition in Note 1.a.i. should apply to all Planning Events. The system should not be considered to be angular stable when generators are pulling out of synchronism. 41. Note 1.a.iii.: This standard should define a minimum damping factor and allow the PC/TP to have a more restrictive damping requirement if they choose to.

Response: 1. The SDT looked at available historical, statistical data and used that data for guidance in re-ordering the table.
2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
3. Planned outages that are long-term need to be provided to the planners in order for them to appropriately represent the topology of the system. This does not imply that one must build in order to accommodate a planned outage and to be responsive to FERC Order 693, paragraph 1725.
4. The referenced verbiage has been deleted from the revised standard.
5. Assessement does not mean that studies have to be run for each of the years, only for Year One or two and five for peak load and for any one of the 5 years for off-peak load. If no changes occurred between the years the assessment will be very simple. However, if the required Corrective Action Plan is delayed, or there is a long planned or forced outage to a major generation or Transmision Facility, or it is believed that some of the sensitivities may have to be addressed, etc., there may be a need to assess each of the years.
6. Agree if that is the case for your System. Each entity is responsible for demonstrating the appropriateness of the assumptions used in the current studies. To some entities this case may be their base case and others it may be a sensitivity case.
7. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Long-term horizon. This does not preclude any entity from running more studies, including for off-peak load conditions.
8. Actions listed in the Corrective Action Plan will more often than not result in higher fault, requiring the installation of even more additional equipment to accommodate the higher fault duty. This requirements ensures that the “entire” effect of the corrective action is captured in the plan. In addition by considering the “entire” effect of a proposed corrective action the entity may find it more economically to propose another action. Therefore, the SDT feels that this should be part of the Planning Assesment.
9. R2.6.1 - The SDT has revised R2.6.1 to delete the reference to market structure.

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R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

10. Curtailment of firm transfers is allowed for some specific Contingencies in compliance with FERC Order 693.
11. R3.3.3 - The SDT recognizes some may consider these words redundant. However, it should be noted that many commenters have asked for the SDT to add words to make other requirements perfectly clear. Since these words do not hurt the requirement and may help some to better understand the requirement, the SDT has not deleted these words.
12. As noted in Requirements R3.4 and R5.7.6, there is an expectation that facilities are designed to reduce or mitigate the likelihood of Extreme Event situations that expose the System to cascading events.
13. This has been added.

R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenci~~es~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

14. R6 - By meeting this requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2).

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

15. The SDT reviewed each planning event considering the likelihood of the event, the potential outcome of the event and the directives from FERC concerning loss of Non-Consequential Load and determined the expected performance for each event. Then, the SDT re-ordered the events and grouped them by the type of outage and the expected outcomes.

Performance requirements:
16. The SDT has reviewed and revised Tables 1 & 2. In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology.
Cascading outages and uncontrolled islanding can also occur, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies.
The SDT did not change Table 1 to remove "Normal Clearing" because depending on the bus configuration, delayed clearing would result in removing more Facilities from service than normal clearing in the steady state post-Contingency period.
17. The SDT has revised Tables 1 & 2 accordingly.

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18. The SDT has accordingly proposed a definition for Bus-tie Breaker. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 19. The SDT has reviewed and revised Tables 1 & 2. "Firm Transfer" has been replaced with "Firm Transmission Service". 20. P6.2 - The SDT has reviewed and revised Tables 1 & 2. 21. P6.3 - It is true that multiple elements are impacted, but it is still a single Contingency event. 22. P9.1 - The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. A percentage doesn't provide the same limitation and consistency. 23. It refers to the loss of a monopolar DC line or one pole of a bipolar DC line. 24. P9.3, P9.4, and P9.5 - The SDT feels that the loss of a bipolar DC line is a multiple Contingency Planning Event. The tables have been revised to provide clarity. 25. Extreme Events 3 - The SDT has revised Extreme Events in Tables 1 & 2 and to comply with FERC Order 693. 26. Extreme Event Descriptions - The analysis of Extreme Events is an effort to assess potential impact of plausible but unlikely events. The selection of events is deterministic, not probabilistic. The SDT also notes that in Order No. 693, paragraph 1834, the FERC gave examples of Extreme Events that the FERC would expect to see in the revised standard. These examples are consistent with the items that the SDT included in the standard as examples of Extreme Events to be considered. For example, paragraph 1834 includes "(1) loss of a large gas pipeline into a region or multiple regions that have significant gas-fired Generation; (2) a successful cyber attack; (3) regulation that restricts or eliminates the use of a river or lake or other body of water as the cooling source for generation; (4) tornado or wildfire, or other event and (5) the loss of older transmission lines, which may not be constructed to meet an entity's present radial ice loading requirements…" In paragraph 1834, the FERC directs NERC to expand the list of events with examples such as those described in the paragraph. 27. Extreme Event 1 - In the existing Table 1 the non-simultaneous loss of two unrelated elements with System adjustment in between is in Category C3, the simultaneous loss of two circuits on a common structure is in Category C5. In the proposed standard Table 1, Extreme Event 1 covers loss of two unrelated elements with no System adjustment in between. If the reference is to a single Contingency, then the focus should be on the Contingency rather than the number of elements affected by the Contingency. 28. Extreme Event 2c - Event 2c is the loss of a station. Event 2e is the loss of Load. The loss of a single large Load or major Load center assumes that multiple events need to occur to realize this level of impact. 29. Extreme Event 3f - The SDT has reviewed and revised Tables 1 & 2. 30. Extreme Event 3g - The issue reflects the exposure during a period where an entity is taking older lines out of service to rebuild them to newer design standards. 31. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard. 32. The SDT has provided a definition of a Bus-tie Breaker. 33. Shunt devices have been added to the table. 34. This is now listed as a multiple Contingency (P7). 35. The table has been re-done to emphasize that you need to study events and not just single pieces of equipment. 36. One mile was based on the SDT's review and understanding of existing conditions. 37. The SDT has revised the table (P6) to make it clear that this is for a single pole.			

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Commenter	**Yes**	**No**	**Comment**
38. The language referring to a spare transformer has been deleted form the table. 39. Editorial error has been corrected. 40. The SDT has reviewed the definition of angular Stability and feels that it is appropriate. 41. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard.			
MEAG Power	☑		To the extent that the new standard is more stringent, additional time should be allowed to implement the corrective action plan, with fines suspended until reasonable time has passed to allow implementation. I.E., If the solution is 20 miles of new 500 kV T/L, then allowing fines to the short-term horizon is unreasonable – building 20 miles of 500 kV T/L is not possible in 2 or 3 years.
Response: The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard.			
MISO	☑		The Midwest ISO appreciates the opportunity to offer the following recommendations: 1. Requirements for providing modeling data in R1. are redundant with the exising requirements of MOD-010-0, MOD-012-0, and MOD-016-0 through MOD-025-1. Adding these requirements to the TPL Standard is unnecessary and may create confusion. 2. The Standard does not address the return of direct (consequential) load loss following a contingent event. How long of an outage event acceptable?
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The proposed TPL-001-1 standard does not place a limit on the amount of Consequential Load Loss or the outage duration. In Requirement R3.3.2.1 the Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. The SDT believes it is first necessary to obtain data on these items to allow comparison of similar sized Systems and it drives transparancey to expected outcomes.			
MRO	☑		The MRO commends the SDT on the difficult task of rewriting some of the most important NERC standards: the TPL standards. The MRO has a number of comments and suggestions. 1. Load modeling data in R1.1 and R1.2 do not belong in the TPL standards. It should be provided for in the MOD standards which provide the numerous load model data requirements. At a minimum, R1.2 should be revised to only require documentation of stressed system conditions. It is unnecessary and micro management to provide for "measurement during stressed System conditions". Further, it is unusual standards drafting to provide for a measurement of load in an assessment standard. 2. R1.4 should be revised to separate "known planned outages" from the rest of the requirement in

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Commenter	**Yes**	**No**	**Comment**
			separate sentences. This is because the reference to spare equipment outages does not have any bearing on the "known planned outages" requirement. Further the consideration of spare equipment strategy is not explained enough to understand what is required here. Further it is not clear as to what equipment must have consideration of spare equipment. The MRO recommends that R1.4 be rewritten as follows: "Known planned outages. Long-term forced outages for transformers with low-side voltages of 100 kV and above and generator step-up transformers should be identified where lack of spare transformers could result in outages of the transformers over the annual peak demand hour." 3. It is unreasonable for R1.5 to provide that planned facilities that are included in System Assessments include circuit breakers, and protection system equipment. These two items should be dropped from R1.5 since these are engineering details that are typically not available at the time that the System Assessment is made. 4. R.2.1.1 - The system peak load study requirements for studies for two of the near-term period seems to be excessive. The MRO recommends that only one year in the near-term period be required. 5. R2.6 should be deleted. The MRO believes that R2.1 and R2.4 are sufficient in describing when current studies are required. R2.6 will result in unnecessary restudy of the system. Alternatively, if R2.6 is kept, then the requirement should be a performance requirement, that as long as material changes do not require restudy then restudy is not required. The Transmission Planner and Planning Coordinator could be required to document why restudy is not required. Material changes should be expanded to refer to only those "significant" transmission line additions or generator additions. 6. R2.71 should be revised to delete "including the duration of interim Operating Procedures" or else the SDT should explain what is meant by this with additional information about what interim Operating Procedures are. 7. R2.7.1.1. should be revised to delete the requirement for project initiation date. This information is not typically available at the time of performing a System Assessment since this is detailed engineering information not pertinent to planning. 8. R2.7.5 should be deleted. The MRO believes the such detailed review of the status of the installation of projects to be beyond the scope of the TPL standard. Since NERC has no authority to require the installation of facilities, how does NERC have authority to require a review of the status of such facilities?

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			9. R3.2.1 and R3.2.2 seem unnecessary details that are micro-management of the planning process. Both requirements could be met by the transmission planner and planning coordinator with general statements of little value. Also, relay loadability is included in facility ratings and does not need to be covered in TPL. 10. In Table 1, "a shunt device (including FACTS devices)" is too general. Arresters and potential devices for metering and relaying are shunt devices. This should be changed to a specific listing such as: transmission capacitors (100 kV and above), transmission reactors (100 kV and above), …" and whatever other devices that the SDT intends to be included here. 11. In Table 1, Single pole of DC line should be moved to P1. 12. In both tables, "monopolar DC line" should be replaced with a "single pole of a DC line". 13. The revised tables are confusing in descriptions of various outages particularly since the interconnected transmission system has been planned for the past decade using the previous Table I. The SDT should limit its changes to Table I to a limited number of changes that have been known to cause issues in the past rather than raising the bar in a number of cases. 14. The Extreme Event descriptions in Table 1 should be revised to provide definitions of local area and wide area. 3 d. (3f.) and 3 c. (3 e.) are duplicates and should be combined. Wide area events as listed are such unusual events, which are difficult to analyze or model. The requirement should provide that the number of these wide area events to be studied is limited to a minimum of one. 15. The MRO does not believe that contingency reserve is necessarily synonymous with spinning reserve. The SDT should clarify note ii to Table 2. 16. The SDT should clarify the wording in the tables to better explain the events which are either above or below 300 kV. For example, in P5 change 1. IS IT "A Transmission circuit followed by a System adjustment above 300 kV followed by the loss of another Transmission circuit above 300 kV." or is it "A Transmission circuit followed by another Transmission circuit resulting in impacts on 300 kV facilities"? P5 3. should be revised to say, "A transformer with a low side voltage rating above 300 kV followed by a System adjustment followed by the loss of another transformer with low side voltage rating above 300 kV." or is it "A transformer followed by the loss of another transformer resulting in impacts on 300 kV facilities."

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Commenter	Yes	No	Comment
			17. R2.1.3 - R2.1.3 reguires sensitivity studies that involve many potential scenarios that would be difficult to create in a Planning Assessment. Planners can not model the unknown and to assume the unknown may be a difficult task to complete. Instead of "shall be run and", the language should be "shall be considered based on current knowledge of system including" 18. Extreme Events description for common right-of-way should be defined. Does this include line crossing points? Suggest exclusion for corridors one mile or less similar to P9.1. 19. The language description of the even should be substantially the same between Table 1 and Table 2. Table 2 format is a bit cleaner with initial condition and event separated. Table 1 should follow this format. 20. The loss of a shunt device (e.g. SVC) should be added to Table 2 (P1.4). 21. Note 1ai. to Table 2 refers to event P3.2 which doesn't exist in the Table 2. 22. Note 1aii. to Table 2 allows generating units to "cascade trip" for certain events that were this would not be allowed in the existing TPL standards. The MRO recommends that the more of the events be listed in 1ai. so as to at least maintain reliability. 23. Note 1aiii talks about acceptable damping. NERC should have a standard requiring development and documentation of damping criteria by the planning coordinator. 24. P9 should be changed from referring to a monopolar or bipolar dc line to a single pole of a DC line. THE FOLLOWING ARE RON MAZUR'S COMMENTS. 25. The MRO does not believe R1 is required in this standard. The modelling standards should cover the requirement of the data owners to provide data to the PC. Further this data needs to be provided to the TP as well. 26. R1.4: requires planned outage data to be provided to planners. The MRO does not believe this is a requirement for planning. It is not economic to add facilities to accommodate future planned outages. Secondly, the Table 1 multiple contingencies already mandate that planners consider the

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			impacts of an outage with system adjustment followed by testing for the next contingency. 27. R1.5: requires the PC to define "planned facilities" which should be included in the model. This will lead to inconsistency what is modelled, as experience has shown that there will be a wide range of assumptions in the definition. This standard should offer a definition for stakeholder debate. The SDT should clarify what is intended by including Protection System Equipment and control devices. 28. R2: The SDT should define the elements of an acceptable assessment in more detail. 29. The MRO recommends that the need to assess Plant Stability be removed from this standard. The generator connection standard and the proforma tariff interconnection process ensure the plant stability meets performance requirements. The System Assessment provides an overall assessment of the integrated system performance, which includes the impact of the plant. This requirement appears to be redundant. 30. R2.1: It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 31. R2.1.3: The requirement for sensitivity cases is excellent. The SDT should consider: R.2.1.3.1: separate real MW load variation and Power Factor variation R.2.1.3.2: clarify the intent of modification of expected transfers. Does this apply to firm transfers only, or does it also encompass non-firm transfers. ..R.2.1.3.4: Instead of a sensitivity, the reactive devices should be included in the Table 1 &2 contingencies. If the intent is to investigate robustness to voltage instability, the SDT should clarify. R.2.1.3.5: Generation additions/retirements should be removed as this is covered, or should be, by the interconnection standards. The SDT should clarify.the need for generation additions/retirement. 32. R2.2: The long term assessment should also include an off peak case with simultaneous transfers to provide some indication if the system performance is expected to degrade. 33. R2.3: The short circuit study is not a reliability assessment issue but a design issue that is more appropriately covered by a Facility Rating Standard. The time required to conduct and report on this analysis in an assessment is better spent on more contingency or sensitivity analysis. 34..R2.4: Similar to the comment on R2.1,. It is important to assess off peak loads with high simultaneous transfers as this is the period where extensive economic interchange occurs, and

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Commenter	**Yes**	**No**	**Comment**
			transient stability issues arise as less uneconomic peak units are off, leaving the load to be supplied by remote generation with reduced local reactive supply, voltage and damping control. 35. R2.4.1: Should be clarified to limit the detailed modeling to local areas where the planner expects an emerging voltage recovery issue due to unusually high concentration of induction motor load. This is a local issue, and a bulk system reliability issue that is imposed system wide. The MRO believes this should be moved to the sensitivity case requirements R2.4.3. 36. R2.4.3: Sensitivity Case requirements should mirror the steady state comments, subject to the suggestion provided above for R2.1.3. That is: ..R.2.4.3.1: should also include power factor variation (actually a separate requirement) as in the stability world, the dynamic modelling of load has a significant influence in meeting transient performance requirements. R.2.4.3.2: I agree it should simultaneous non-firm transfers. This should be applied to the steady state sensitivity as well (see R.2.1.3.2). ..R.2.4.3.3: delete ..R.2.4.3.4: Needs to be clarified. See R.2.1.3.4. . R.2.4.3.5: see R.2.1.3.5 37. R2.5: Plant stability analysis should be deleted. 38. R2.6.1: Nowhere else in the standard is there a requirement to assess reliability impacts of market structure changes, so why would a study become invalidated if there is a change in market structure. It would seem to me that the operation of any market would have to respect the reliability criteria. 39. R2.7: Corrective Action Plans: Is the intent that corrective action plans also address issues raised by the sensitivity studies. The MRO argument would be that it should not be mandated. The plans are developed to meet base case needs which are based on expected load forecasts, transfers, etc. Sensitivity studies are done to measure the robustness of the base case plan. It should be left up to the Planner to decide if the plan is adequate based on the likelihood of the scenario studied, even if the sensitivity analysis shows some performance violations. 40 Also, if rationale is provided for contingencies selected as they are expected to be most severe, then by default those not selected are less severe. Why is there a requirement to explain why you did not select a contingency. 41. R3.4: Requires extra analysis compared to TPL-004-0. Developing mitigation for Extreme Events

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Commenter	**Yes**	**No**	**Comment**
			can require significant work. Since there is no requirement to implement corrective plans for Extreme Events, what is the purpose? 42. R3.5: Generator tripping should be added in addition to runback. Generator tripping is used extensively in regions where remote generation is delivered via long transmission. Generator tripping should be an available option for the planner to use as opposed to requiring justification as a regional difference. 43. R4: The requirement to assess Plant stability is redundant as this is assessed as part of the generator interconnection. It should be deleted. 44. R4.5.2: The MRO disagrees on the need to define mitigation for Extreme Events. 45. R4.6: Should be deleted. 46. R6: Requires distribution of results and "coordinating analysis of these results through an open and transparent process". Can the SDT clarify what the intent is? As written, it implies the PC/TP just shares assessment results with neighbours. The MRO believes there should be a requirement to conduct joint assessments on inter-regional transfer capability. 47. Table 1 Performance Requirements: • As this is a steady state table, how does one assess if voltage instability, cascading outages or islanding occurs? • Generator tripping for single contingencies should be added to the allowable actions. • How did the SDT classify which event was single contingency vs. multiple contingency vs. extreme? Was statistical data analysed? • What is a non-bus tie breaker? Is this any breaker that is not a bus tie breaker? • Event P2-3 should be relocated to the P1 event category. • What is the SDT rationale for defining bus faults >300 k as single contingency events? Is there any statistical dat to warrant this extra requirement? Now a Cat C? Since little load is served off >300 kV it may be a moot point. • P6 single contingency: What is the justification for classify P6-2, a bipolar dc loss as a single contingency? The existing standard classifies this event as a Cat C multiple contingency event? • P6-3: Why is a breaker fault classified as a single contingency? One would assume such a fault would be cleared by backup protection resulting in the loss of multiple elements? • P9-1; Is there any justification for selection of one mile? Can it be two miles? More? Why not no more than 5% of line length? Would the fact that there is line shielding be justification for

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Commenter	**Yes**	**No**	**Comment**
			increased length? 48. Extreme Events • Event 3.g: what is the rationale for distinguishing between old vs. new design for the loss of multiple lines due to icing? Is the SDT implying that new lines must be designed to prevent multiple line loss due to icing? 49. Table 2 Stability Performance • MRO Comments on Table one for the same contingencies should also be applied here. 50. P6-2 should be a multiple contingency, as it is in the existing TPL standards. 51. P9-3: should be an extreme event. 52. P9-6: Please clarify the requirement to indicate that it relates to long lead times. 53. The definition for Angular Stability should be modified to allow planned tripping of a generator following a line trip. Why are generators allowed to pull out of synchronism for other planning events? This is cascading. The SDT should clarify if they are refering to local or regional damping modes in 1.a.iii.

Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
2**.** The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725.
3. The SDT does not agree. The SDT believes circuit breakers and protective equipment should be considered when developing criteria since these can affect System performance.
4. The SDT feels that requirement to run a peak load study for two of the years in the Near-Term Horizon is a minimum required for an adequate Planning Assessment. The SDT felt that the Year One or two study should provide operations with the best information to transition to the operating horizon. The year five planning study is the first near term study from the long term set. Five years is a short time if unexpected new facilities are required.
5. R2.6 - The SDT has revised this requirement in response to the numerous comments received.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market~~

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Commenter	Yes	No	Comment
~~structure changes~~ the study shall be five calendar years old or less. **R2.6.2**. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. **R2.6.3**. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~ 6. Interim Operating Procedure is required to ensure that the all the performance requriements in Table 1 and Table 2 are met. It could include SPSs, pre-Contingency interruption of non-firm Loads, uneconomic generation dispatch, etc. The SDT recgnizes that this is a temporary measure until a permanent solution is put in place and that is why its duration is required. 7. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6) Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time. 8. The standard requires that the identified future deficiencies be addressed by the Corrective Action Plan. The standard does not prescribe what this plan should be but entities have to demonstrate that the Corrective Action Plan or its alternatives will in fact be implemented in time to address the identified deficiencies. If the parts or all of the Corrective Action Plan turns out to be unrealistic due to something like a regulatory order, you still need to meet the performance requirements and a revised or new Corrective Action Plan that meets the performance requirements will need to be developed. The determination of when to update the Corrective Action Plan is based on good engineering judgment. 9. R3.2.1 & R3.2.2 - The SDT has received numerous comments in support of these requirements. Requirements R3.2.1 and R3.2.2 are included to provide clarity on simulations in response to FERC Order 693. Relay Loadability is included to provide the connection between facility ratings and planning studies. The SDT has not made changes in response to this comment. 10. The SDT has revised the table references to shunt Contingency events and removed the paranthetical reference to FACTS devices. The SDT believes it is more appropriate to leave the event more general based on the difficulty of maintaining an up to date reference to emerging technologies. 11. The SDT concurs with your observation. We have made several changes to the performance table organization based on industry input. The single pole DC outage is now reflected as a P1 Planning Event. 12. The SDT concurs with your feedback and the suggested change has been made in Tables 1 and 2. 13. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for Facilities above 300 kV and has adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. The SDT has retained a higher			

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Commenter	**Yes**	**No**	**Comment**

expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Considerations in Q20 through Q23 for additional information. The SDT believes that this approach is consistent with FERC Order 693.
14. The SDT has revised the Extreme Event references and has removed the duplications you reference. The reference to local and wide area events has been retained as we did not receive a significant amount of comments opposing its use and it seems to be generally understood that local are extreme Contingencies eminating from a single location (substation, plant or ROW), whereas the wide area tend to cover a much larger landscape due to a natural disaster or cyber attack. The TP is given flexibility in which Extreme Events it wishes to cover, see Requirement R3.4.
15. The SDT agrees and has revised the note accordingly.
16. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard based on feedback from the industry and input from SDT members. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements the SDT feels the industry will find valuable. The SDT believes the new format will more closely meet your needs.
17. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirements R2.1.3 and R2.4.3 have been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirements R2.1.4 and R2.4.4 have been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own system. The sensitivity studies do not in themselves establish the need for a plan, only the areas of the system for which the analysis is needed.

R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

P5.3 - The table format has been revised for clarity. We have added notes at the end of each table to clarify when a transformer is considered EHV (above 300 kV) or a BES transformer below the EHV level.
18. Tables 1 and 2 have been revised to bring greater clarity.
19. The SDT revised the performance Tables 1 and 2 for clarity based on industry feedback. The SDT has included the initial condition column in each and the events correlate one to one in both tables.

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20. The single Contingency loss of a shunt device is now included as Planning Event P1.4 in Tables 1 and 2.
21. The SDT has corrected the problem in Table 2.
22. The SDT believes that we are not reducing the reliability of the System as compared to the existing standards.
23. The SDT has reviewed this requirement and has determined that at this time this is not appropriate for a North American standard.
24. Tables 1 and 2 have been revised to include a variety of new improvements. The reference to monopolar is now "single pole of a DC line". The SDT has however retained a bipolar DC line outage; see Planning Event P7.2.
25. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
26. The SDT has revised this requirement based on industry comments to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725.
27. The requirement for the PC to define planned Facilities has been deleted from the revised standard. The SDT did not receive many requests for additional clarification of Protection System equipment and control devices and therefore did not revise the standard to address this concern.
28. The SDT has modified the assessment language dealing with steady state analysis in Requirement R2.1 to better define those requirements along with adding Requirement R2.1.4 to allow any additional sensitivities to be run that may be deemed necessary. In addition, Requirement R2.2 has been revised to specifically address steady state analysis: Requirements R2.4 and R2.5 have had many changes to better address the Stability portion of the assessment, Requirement R2.6 better details what past studies may be used in the Planning Assessment, and Requirement R2.7 better addresses Corrective Action Plans and System deficiencies. The SDT believes that all these changes result in better defined portions of the Planning Assessment.

R2.1. ~~The steady state portion of~~ The Near-Term Transmission Planning Horizon ~~Planning Assessment~~ portion of the steady state analysis shall ~~address all five years of the assessment period~~ be assessed annually and be supported at a minimum by the following annual current studies, supplemented with qualified past studies as ~~shown~~ indicated in Requirement R2.6:

R2.1.4. In addition to those sensitivities mentioned in Requirement R2.1.3, any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

R2.7. For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities. The Corrective Action Plan shall:

29. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that

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Commenter	Yes	No	Comment
this was responsive to FERC Order 693. 30. Requirement R2.2 requires as a minimum a peak load study for one of the 5 years in the Near-Term Horizon. This does not preclude any entity from running more studies, including for off-peak load conditions. 31. The standard is providing some guidance on what needs to be included in sensitivity studies without being totally prescriptive. In response to some comments, the standard was modified to clarify the language to state that at least one of the sensitivities listed in Requirements R2.1.3 and R2.4.3 should be studied and reasons be given for not studying the other ones. Furthermore, the standard also allows for entities to study sensitivity not included on the list that are more appropriate for their respective systems. 32. R2.2 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 33. R2.3 - The SDT respectfully disagrees and believes that the requirement for short circuit analysis is an improvement and covers a gap in the existing Transmission planning standards. It is essesntial that as System changes are introduced that increase the strength of the System and result in increase short-circuit fault currents, that the Transmission planner not simply look at steady-state Facility Ratings but also consider the short-circuit as well. Having steady-state, short-circuit and Stability in a single cohesive standard ensures that the Transmission planning engineer is evaluating all aspects of proposed changes to the System. 34. R2.4 - The Draft 2 version remains unchanged in regard to your comment. There was no overwhelming response from industry that compelled the SDT to make the change proposed. The standard requires off-peak analysis for near-term. In the long-term Requirement R2.2 states "…at a minimum, a current System peak Load study is required annually." This requirement is to capture long lead-time events for peak-Load periods. The peak system is typically the more troublesome period for most planners as Loads are higher and Facility Ratings are lower. Your concern is valid that in the off-peak, transfers across a system can be elevated and it is expected that if a particular System is subject to heavy transfers that a prudent Transmission planner would cover such situations based on their own identified need through sensitivity studies. Howver, such off-peak anlysis is not mandated by the standard for the Long-Term Planning Horizon. 35. The SDT feels that the Load model used in the study should represent actual conditions as accurately as possible. It has been shown during the reconstruction of the events of the August 14, 2003 blackout in the Northeast that the Load model was critical. One of the recommendations involved developing better Load models. 36. To the degree possible, the SDT has revised the standard to better align steady state and stability sensitivity lists. 37. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 38. R2.6.1 - The SDT agrees with your view and references to market structure changes have been removed in Draft 2. 39. Agree. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard was be modified to clarify this. 40. In developing a rationale why a selected Contingency is the most severe will require some sort of comparison to other Contingencies. In doing so the explanation required in the standard is already addressed. 41. The SDT feels that the current TPL-004 provides limited value to improve System reliability. Performing studies and not even considering			

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possible corrective actions (as is the case with the current standard), may result in over looking relatively inexpensive corrective actions which could significantly help improve reliability. It is appropriate to add another requirement to help improve reliability System development. The purpose of the requirement is to assess the risk of cascading outages or a catastrophic event, develop corrective actions and actually implement such actions if it is reasonable, for example installing a SPS. This is also consistent with Paragraph 1833 in FERC Order 693, which directs NERC to modify TPL-004-0 to identify options for reducing the probability or impacts of extreme events that cause cascading.
42. This has been added.

R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

43. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693.
44. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard.
45. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693.
46. R6 - By meeting the requirement for "coordinating analysis of these results through an open and transparent process", the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement. (see R8 in draft 2)

R8. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

47. Performance requirements:
The Draft 2 version includes a new Requirement (R6) which indicates that each TP must define and document proxies used in simulation studies to identify System instability for conditions such as cascading outages. voltage instability, or uncontrolled islanding.
In the steady state time frame, voltage instability can occur typically during high power transfer and/or peak demand periods. Voltage instability can be assessed using a long-term Stability program. However, it can also be assessed using a power flow program that simulates governor action. There are a number of IEEE papers (e.g., G. Morison, B. Gao, and P. Kundur, "Voltage stability analysis using static and dynamic approaches," IEEE Transactions on Power Systems, vol. 8, no. 3, pp. 1159 – 1171, August 1993) that can provide suggestions on the methodology.
Cascading outages and uncontrolled islanding can also occur in the steady state time frame, for example, when the Transmission Facilities load beyond the corresponding relay trip settings. This could cause uncontrolled tripping of Transmission Facilities beyond those required to clear the fault. Even though these events are rare, the Transmission Planner should be aware of their possibility when performing studies.

R6. For the short circuit portion of the Planning Assessment, as described in Requirement R2.3, each Transmission Planner and Planning Coordinator shall assess the short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties.

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The SDT agreed to make this change, Requirement R3.5 of the second draft of the standard now allows genration tripping for single Contingencies.

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

To address the directive from FERC in Order 693, the SDT classifies Contingencies by events instead of by the number of Transmission elements lost. One event, for example loss of a breaker, can remove from service upon fault clearing all elements connecting to the breaker. Statistical data available from regional databases were analyzed in developing the draft standard.

A Bus-tie Breaker is often used in straight bus substation layouts to sectionalize an otherwise long continuous bus into smaller sections. The SDT has proposed a definition of a Bus-tie Breaker in the second draft.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

Tables 1 and 2 have been revised and Event P2-3 has is now shown as Planning Event P1.5, and loss of a bipolar DC line has been reclassified as a multiple Contingency event.

The SDT recognizes that bus section faults can and often do trip multiple Transmission Facilities. The Planning Event P2 defines single Contingency events that are somewhat lower probability than those in P1 but often result in higher consequence impacts due to loss of multiple Transmission elements for the single electrical fault. In more reliable station designs (ring, breaker and a half,etc) this type of condition is minimized. The new TPL Draft 2 continues to emphasize a higher expectation of performance for bus section faults and other P2 events on the Transmission System above 300 kV. See Summary Response for questions Q20 through Q23 for more details on the team's rationale for continuing to seek this level of reliability improvement.

The SDT concurs with your view and has made the change. A bipolar dc loss is no longer a single Contingency Planning Event.
You are correct in describing the outcome – multiple Facility outages. However, the SDT is describing an internal fault of a breaker, not a stuck breaker condition. Therefore the SDT is treating these as a single Contingency event. The SDT agrees that these are lower probability events than the "typical single Contingency" events but they pose greater risks. The SDT has separated the single Contingencies as P1 and P2 based on their probabilities of occurrence. Also, allowable responses to the P2 events differ from those for the P1 events. It is noted that stuck breaker events are treated separately as P4 Planning Events.

The choice of one mile was based on a review of various regional practices.

48. The reference to this item has been removed and more general weather conditions resulting in extreme Contingency conditions are assessed in the Extreme Events area.
49. See comments for Table 1.

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Commenter	**Yes**	**No**	**Comment**
50. The SDT agrees and has revised the table accordingly. 51. The SDT has reviewed this requirement and has determined that at this time this is appropriate for a North American standard. 52. The SDT has removed the terminology referring to spare transformers. 53. The SDT has reviewed the issue and revised Requirement R5.5.3 to provide clarification. **R5.5.3**. Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:			
Muscatine P&W	☑		Muscatine Power & Water (MPW) is a municipal utility with approximately 33 miles of 161 kV lines (2 lines) and 33 miles of 69 kV lines with three – 161/69 kV substations and seven – 69/13.8 kV substations. The service territory is approximately 24 square miles. Our last system peak was 149.9 MW on July 29, 1999 with a more recent peak of 146.9 MW on July 17, 2006 with generating capacity of approximately 253 MW from four units. The main problem we have is keeping up with the standards changes with our limited resources. We would suggest: 1. It was good to see the definitions section. We would also suggest including all acronyms including those in common use. Acronyms have become so common and they are now being reused to mean different things to different groups that for new people, multitasking individuals, or those not dedicated to a specific standard acronyms add confusion. Where possible, we would suggest using existing terms and, if appropriate, preferably already defined or have them defined in IEEE standard #100 dictionary. 2. Can you address adequate documentation? I'm not looking for detail formats or requirements but more minimum requirements and suggested layout etc. One of the problems I have during audits is how much documentation to provide without going over board. More is not good considering time requirements. Our goal is to make it easy for us and the auditors. We met the standard but have we proved it. Being a small utility with little impact on the bulk system how much should we provide? 3. In our region the MAPP Design Review Subcommittee (DRS) and in some cases the Subregional Planning Groups (SPGs) review new and proposed changes to facilities. In many cases they would have to approve any RAS or SPS and thus provide a peer review/reasonable and workable check. 4. R.2.6.1 - Being a small utility we are concerned about the planning study must be less than 3 years old. We budget for studies every three years but adjust that based on whether material changes have occurred to the system. Our last cycle was 6 years only because our load hasn't been growing and we still haven't hit our peak of 1999. Since we are dependent on consultants, we also have a concern for how long it can take for them to complete the study. Since we are small the bigger customer gets the attention. We do use the same criteria for near and long term planning horizons. We also participate in MAPP and ITWG studies for the annual and bulk system review and

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Commenter	Yes	No	Comment
			since our issues in studies are more local rather than the bulk transmission system. How should/could the sensitivity studies be covered for us at the regional level? 5. 300 kV and above questions: MPW is a small utility that doesn't have any facilities above 161 kV or any DC lines. I can see requiring more stringent performance for EHV and possibly lower voltage facilities in some cases, however, whether to allow the loss of Non-Consequential load should be left to local entities to decide since the cost of the "corrective action" could exceed the cost of the load loss and put undo burden on the customers. Depending on the type of load the customer may not want/be willing to pay for the extra reliability. If ordered, how will the cost be recovered? The cost should be recovered by the users not just the local customers. Thanks for the opportunity to comment!
Response: 1. The proposed definitions in the draft standard will be incorporated into the Glossary of Terms when the standard is approved. We believe it is better to have the terms listed in the NERC Glossary of Terms rather than pointing to the IEEE standard since the NERC Glossary is more readily available for use in the reliability standards environment. We have reduced the number of definitions in Draft 2 to try and have a more pointed impact where a definitional term is most needed. 2. Your concern is a compliance matter and not directly related to the reliability requirements. Although not yet available in Draft 2, the SDT will be adding compliance measures in a future draft. If the measures do not clearly address your concern please raise a more specific question related to the appropriate requirements/measures. 3. Thank you for your comment. 4. R2.6.1 - The SDT has revised R2.6.1 to allow the use of past studies that are 5 calendar years old or less. **R2.6.1**. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less. 5. The SDT has added greater detail to Tables 1 & 2, which provides for more situations where it is acceptable to lose Load. With regards to the loss of Load, the standards don't address cost recovery.			
NERC TIS	☑		1. In definition of "CONSEQUENTIAL LOAD," misoperations need to be defined better or removed, i.e. inadvertent tripping of elements due to protection system failure, including inadvertent SPS operation, may cause loss of load NOT connected to the element tripped off. In context of the definition, it appears that the misoperation should be on the protection system for the element that is tripped. {PARTLY COVERED} 2. Even when post-contingency voltage remains within prescribed limits, some voltage-sensitive customer load could still be dropped off due to their inherent sensitivity to allowed changes in voltage. Should such cases be considered as dropping non-consequential load or are the performance requirements met as long as post-contingency voltage stays within the prescribed limits? Such load losses can rarely be predicted by steady state analysis unless the

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Commenter	**Yes**	**No**	**Comment**
			loads and their distinct characteristics are explicitly modeled, but may be detectible in dynamic analysis since it is often the first swing voltage excursion that trips such loads. 3. Assuming the standard is passed, especially if the bar is raised, there should be some reasonable implementation period specified to allow entities that do not meet the standard's requirements presently and time to implement changes to become compliant. 4. Why is there a 300 kV threshold? Is there evidence that increasing the redundancy of the high voltage network will provide the largest reliability benefits? 5. Need to specifically define when it is OK to use "permanent" SPSs to meet performance requirements following the first contingency, i.e. separating a balance island should be OK. It is OK to utilize temporary SPS while the permanent corrective measure is being put in place. 6. Need to define, perhaps in the list of definitions, what is the "bus-tie breaker." Differentiation of center breakers in breaker-and-one-half schemes is a crucial item not to be subject to interpretation and possible confusion. 7. Need to clarify that "stuck breaker", regardless of whether cause by protection system failure, breaker failure to operate, or a slow breaker, is de-facto delayed clearance and causes additional contingency (ies). 8. Firm Transfer Cell for P3 does not make sense. 9. Need to strengthen the notion, in the bullets at the top of Table 1, that the assessment should also cover n-0 or "normal state (seems to be adequately covered in the body of the standard, but does not jump out from the Table 1 bullets at the head of the table.) 10. Include SHUNT DEVICES in P3–P9 planning contingencies. The same comment is applicable for stability table. 11. Need to clearly specify what documentation would be required to fulfill the standard's requirements for assessing extreme contingencies. 12. Replace "all" in the Extreme Events subheading with a more appropriate term. 13. Replace "all" in the table for Extreme Events for both Steady State and Stability tables with a more appropriate term to manage documentation requirements. 14. Use different designations for planned and extreme events in steady state and stability tables, e.g. PS and ES for steady state and PD and ED for stability (D for dynamic). 15. Throughout the tables, do not refer to "internal" breaker faults but use breaker fault instead. Faults can occur internal to the breaker, flashed bushings, or a fault (on or within) a free-

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Commenter	**Yes**	**No**	**Comment**
			standing CT associated with the breaker. 16. Modify bullet 5 in the Stability Table to include SPS failures to read: "Simulate the removal of all elements that Protection Systems, SPS or RAS systems, and controls are expected to disconnect for each Contingency." If an SPS or RAS is expected to operate for a contingency, it must be modeled as such for that contingency study. 17. In R1.2 need to add "for the period analyzed" and defined what "stressed" conditions means. 18. In R 2.1.3.7 need to insert "long-term" in front of "transmission outages." There is also a need to clarify/describe/define what long-term transmission outage is. 19. There are concerns, particularly for NON-vertically integrated TPs, about need of including Plant Stability requirements. 20. Define what "material" change is in R2.5.2. 21. Presumably the standard will be stamped with a CEII designation 22. Additional granularity should be included showing the correlation between Requirements and their applicability to any of the Functional Model Entities cited in the Standard. 23. Obligations to study and share results of the following should be clear in the TPL Standards: • Analysis of impacts on your system for contingencies outside of your system footprint. • Analysis of impacts on other systems for contingencies within your system. The owners of the other systems should be notified of your findings and joint analysis should be done if warranted. • Powerflow and stability analysis of contingencies that have interconnection-wide impacts. This may best be accomplished through modifications to existing standard TPL-005.

Response: 1. The SDT revised this definition in response to various comments.

Consequential Load Loss: Load that is no longer ~~served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation~~ connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

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steady state performance requirements.

2. The SDT revised this definition in response to various comments. The SDT believes the revised definition addresses the concern expressed in this comment.

Non-Consequential Load Loss: ~~Load loss other than Consequential Load Loss. For example, Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems.~~ Non-Interruptible Load loss other than Consequential Load Loss. For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss.

3. The SDT is sensitive to need for an implementation policy to allow for Transmission Owners to respond to requirements that involve raising the bar, but an implementation plan was not developed for this posting. The SDT anticipates developing an implementation plan in response to the next posting.

4. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT felt the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if large EHV transformers experiences a catastrophic failure, not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time.

Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are commonly found on lower voltage Systems.

The feedback received from industry was divided related to the SDT’s emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter’s questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT’s approach and indicated that the impact to their Systems would be minimal. Some commenter’s even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

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5. The SDT has revised requirements to include changes related to the allowable use of SPSs related to N-1 events. See new Requirement R3.5 of the Draft 2 TPL-001 standard which indicates SPSs are permitted for automatic generation runback or tripping following a single contingency event. **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~iesy~~ ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 6. The SDT has proposed a definition for bus-tie breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 7. Tables 1 and 2 have been revised to provide greater clarity. The SDT has accounted for both stuck breaker and Protection System failures as two unique Planning Events. See performance table requirements for Planning Events P4 and P5. 8. The SDT concurs and changes have been made to the performance Tables 1 and 2. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. 9. The SDT concurs and has added a P0 Planning Event at the top of Table 1 to address the N-0 (existing Category A) condition. 10. The SDT has modified the tables to include shunt devices where appropriate. 11. Changes were made to simplify and clarify Extreme Event expectations. Please refer to both performance tables and Requirements R3.4 (steady-state) and R5.5.4 (Stability). 12. The statement has been revised to say "For all Extreme Events considered". 13. The statement has been revised to say "For all Extreme Events considered". 14. The Planning Events for steady-state and Stability now correlate one-for-one, so the SDT does not feel a need to distinguish each uniquely. The Extreme Events are not presently listed in a tabular format with the formality of the Planning Events. This is somewhat intentional to draw greater emphasis and focus to the Planning Events. If you feel changes are needed in our presentation of the Extreme Events within the performance tables, the SDT would be open to a suggested format from TIS. 15. Tables 1 and 2 have been revised to explain "internal breaker fault" (see Note 5 in Table 1 and Note 4 in Table 2). With this change the term "internal breaker fault" was retained. 16. The SDT believes that SPS/RAS is included in Protection Systems as defined in the NERC Glossary. 17. The SDT has revised the data and modeling requirements based on industry comments to clarify intent. **R9.** Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information. **R10.** Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission			

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Commenter	**Yes**	**No**	**Comment**
planning horizon, within ninety days of a request for such information. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. **R12**. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information. **R13**. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information 18. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase the length of the "planned outage" that it has considered in its base case studies. 19. The SDT has reviewed the need for Plant Stability and has concluded that it is appropriate to include it in this standard. It also felt that this was responsive to FERC Order 693. 20. The SDT has changed the wording to provide clarity. **R2.5.2**. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant. 21. The Standard is public information. Individual reports may need to be reviewed by the individual entity to ensure compliance with CEII. 22. References to entities have been added. 23. R6 requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's Transmission Planning Process. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890.			
NCEMC	☑		1. Planning Coordinator: The definition of Planning Coordinator should be kept within this document rather than relying on the NERC Functional Model as we believe that this entity has an important role in insuring coordination of transmission and resource plans. Coordination: 2. During the teleconference, one issue brought up was the matter of external contingencies being

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Commenter	**Yes**	**No**	**Comment**
			tested as a part of a TP's analysis. The reply was that this issue will be addressed outside this draft standard (TPL-005 and TPL-006) or would be accounted for in the coordination efforts among Transmission Planners. NCEMC is of the opinion that Requirements R5 and R6 need further details to insure adequate anlysis between and among Transmission Planners having varying local planning criteria so that Seams Issues are addressed that are not currently being address in regional and inter-regional studies. To the extent possible, timing of studies should be required to insure coordination between regional and inter-regional groups. Significant Increase in Study Activity Workload on Transmission Planners: 3. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the “Corrective Action Plan” requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 4. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. A reasonable period for transition is order. Design and Construction Constraints: 5. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project

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			costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 6. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 7. It has already been noted earlier but deserves repeating here: The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 8. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge. Stakeholder Process: 9. As a Transmission-Dependent Utility and Network Customer within 3 different Balancing Autorities with one being a Regional Transmission Organization, NCEMC cannot stress enough the need for a Stakeholder Process for coordination Transmission Planning that may impact Load-Serving Entities and other entities involved. It is critical to address reliability needs of all taking transmission service today and in years to come.
Response: 1. The SDT modified the definition and the definition will be approved with the standard and added to the Glossary of Terms Used in Reliability Standards. 2. R5 (R7 in second draft) requires the determination of the entities responsible for the portion of the studies. R6 (R8 in second draft) requires "coordinating analysis of these results through an open and transparent process". By this requirement the SDT meant a stakeholder process that was set up to meet the requirements of FERC Order No. 890 with regard to an Attachment K filing of a Transmission Provider's			

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Transmission Planning Process. In addition, NERC Standards are to specify the requirements, which must be met and not "how" they are met. The SDT has made a change to clarify this requirement (see R8 in draft 2). **R8**. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~affected entities~~ neighboring systems, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. 3. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 4. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 5. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 6. Cost issues are outside the scope of NERC reliability standards. 7. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 8. Any requests for long-term Transmission service need to be studied in accordance with peformance requirements. 9. This draft standard addresses the requirement for coordination of studies in an open and transparent process (see Requirement R8 in draft 2).			
NCMPA	☑		Much of the language in R1 is redundant, because the MOD standards already address what data are required for modeling purposes. Including data requirements here, as well as in the MOD standards, will introduce the possibility of inconsistencies between the two as well as unnecessary duplication of work for entities providing the data. If any changes need to be made to what data are collected or to whom it is provided, those changes should be made in the MOD standards, not by adding data requirements to this standard. As for most every standard written, some consideration should be given to the cost of meeting the more stringent requirements proposed for this standard. While it might be possible to make incremental improvements in reliability, it may not be cost-effective, particularly given the low probability of some of the events addressed in the standard. Before stakeholders are asked to vote on this standard, a cost-benefit analysis should be performed to provide what would be an otherwise missing, but very important piece, of information about whether the costs of complying with the

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Commenter	**Yes**	**No**	**Comment**
			requirements of this standard are justified based on the reliability improvements that would be achieved.
Response: 1. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. 2. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards.			
OPPD	☑		The terms Bus Tie Breaker and Non-Bus Tie Breaker used in Tables 1 and 2 are not well defined. To prevent misinterpretation of the standard, include diagrams that point out examples of bus tie breakers and non-bus tie breakers for each of the following bus schemes: 1) Single bus 2) Ring bus 3) Breaker and a half 4) Double bus double breaker.
Response: The SDT has proposed a definition for Bus-tie Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
PJM	☑		1. Delayed clearing due to primary relay system communication failure 2. Bus Contingencies should not be included for sensitivity/stressed case 3. Sensitivity case should not be included for long term study 4. Need to clearly define number of studies required for Load Flow/Stability and what performance criteria must be met. • Peak Case • Off Peak • Sensitivity 5. Need to allow SPS operation after a first contingency, system readjustment and a “second “ first contingency. 6. SPSs can include generation tripping
Response: 1. The SDT does not understand the question and therefore can’t respond. 2. Bus Contingencies are just one type of sensitivity that could be included but is not mandated. 3. Sensitivities are not required for long-term. 4. The SDT believes that the number of studies is clearly defined. 5 and 6. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenci~~es~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			

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Commenter	**Yes**	**No**	**Comment**
PRPA	☑		1) P5 and P8 in Tables 1 and 2 – If you keep the "300 kV bar" for distinction between P5 and P8, then please make an exception for P5 to be "Yes" on Non-Consequential Load Loss where load pockets (a.k.a. local load-serving areas) are concerned because "system adjustments" might not be possible to avoid the need for Non-Consequential Load Loss after the loss of another line into the load pocket. Example - A city, which is a type of load pocket, is served by three transmission lines. If one of the lines into the city is removed from service for maintenance, "system adjustments" within the city might not be possible to prevent steady-state voltages from dropping below an acceptable limit after loss of a second line into the city. If during such an "N-1Line-N1Line" Planning Event the city voltages become extremely low, then shedding of some of the city's load should be allowed, i.e. Non-Consequential Load Loss, for all voltages 100 kV and above. In this example, when one line into the city is removed from service, the TOP could either arm an SPS or RAS for automatic load shedding, or alert the operators to possible implementation of an Operating Procedure for manual load shedding. The city, along with its TO and other authorities, may decide by their own wishes to "raise the bar" and add facilities to maintain acceptable voltages for the worst "N-1Line-1Line" affecting only its local area. However, a facility addition type of solution, driven by a "No" for Non-Consequential Load Loss in P5, should not be mandated. "Controlled interruption of electric supply to customers (load shedding)" should be allowed for all voltages 100 kV and above as Footnote (c) in TPL-003 allows. Consistent with this request to allow load shedding for this type of disturbance for all voltages 100 kV and above, FERC Order No. 693 in Paragraph 1825 regarding TPL-003 for Category C disturbances (including "N-1Line-1Line") does not ask for "controlled load interruption" to be eliminated, but rather FERC directed the ERO to modify footnote (c) to Table 1 to clarify the term "controlled load interruption". And please note FAC-010-1, R2.5 – "Planned or controlled interruption…(load shedding)…" for TPL-003 conflicts with "No" for Non-Consequential Load Loss in P5 of Draft TPL. 2) Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as location and ramp-up speed of the AGC unit(s) responding to the generation trip or runback, loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements." Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. It should not matter which method of generation redispatch is employed if all impacts of tripping vs. running back a generator are properly considered and performance requirements are met. The time period for a particular Emergency Rating might require

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Commenter	**Yes**	**No**	**Comment**
			faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. No need for R3.6 with above revision to R3.5.
Response: 1. The SDT has completely reformatted the performance tables in Draft 2 of the TPL-001-1 standard. The new format more closely mimics the existing approved TPL standard Table 1, with enhancements we feel the industry will find valuable. The SDT has responded to industry comments regarding higher performance requirements for facilities above 300 kV and have adjusted requirements for N-1-1 non-generator outages to permit Non-Consequential Load shed post-Contingency following the second event. We have retained a higher expectation for certain N-1 Contingencies occuring on the EHV System. See the Summary Response in Q20 through Q23 for additional information. 2. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:			
Progress–Carolinas	☑		1. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA. 2. Need to define bus-tie breaker. Is center breaker in a breaker and a half scheme a bus-tie breaker? 3. Need to continue to allow interruptions to firm transfers. This is essentially allowing redispatch and is an economically sensible solution to low probability high impact multiple contingencies. 4. Need to clarify if the "stuck breaker" is associated with the first event in multiple event contingencies or does one have to choose a breaker not involved with the first event. Note that a breaker cannot be "stuck" if there is no demand to trip. Therefore, a stuck breaker that is not adjacent to the first event will not have a demand to trip. 5. Need to distinguish what the difference is between a "stuck breaker" and a "[loss of breaker due to] internal fault". The specific meaning could make the difference in the clearing time selected for stability studies (normal clearing time versus delayed clearing time). 6. In the Table 2 (for stability) the last bullet under Planning events says to "simulate normal clearing times unless otherwise specified". Does this mean that "stuck breaker" events should be simulated with normal clearing times? Note that in the real world, internally faulted breakers may clear in either normal or delayed clearing time, depending on the relaying and CT configuration.
Response: 1. The limits cited are consistent with the registry criteria, Large Generator Interconnection Procedures, and FERC Orders. 2. No, a center breaker in a breaker and a half scheme is not considered a Bus-tie Breaker. The SDT has proposed a definition for Bus-tie			

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Commenter	**Yes**	**No**	**Comment**
Breaker in the second draft. **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.) 1. Tables 1 and 2 have been revised to replace "firm transfer" with "firm Transmission service". 2. The SDT agrees and appreciates the feedback. The SDT has re-worked the tables, and believes the wording used for stuck breaker will satisfy your concern. Please see Planning Event P4 in each performance table. 3. Tables 1 and 2 have been revised to provide clarity. Please see Planning Events P2.1 and P2.3. 6. The sentence "simulate normal clearing times unless otherwise specified" refers to the events sepcified in the Tables. A stuck breaker would have clearing time that is "otherwise specified". The intent is to simulate "real world" events using the clearing times appropriate for the specific fault and breaker/Protective System configuration.			
Progress–Florida	☑		General Comments 1. NERC Standards TPL 001-0 through TPL 004-0 are approved standards that only required modifications pursuant to FERC Order 693. In this proposed draft standard TPL 001-1, the Standard Drafting Team (SDT) has far exceeded the recommendations suggested by FERC in the Order and has created unnecessary confusion. We disagree with the SDT's decision to combine NERC Standards TPL 001-0 through TPL 004-0 into one standard. Some changes to the existing TPL Standards may be warranted. One particular improvement would be clarifying the tables such that the table for TPL-001, for example, would only contain the performance criteria for Category A, with footnotes only applicable to that category, clarified as directed by FERC in Order 693. Similarly, TPL-002 would only contain performance criteria for Category B, and so on. In addition to combining the standards, the SDT has significantly changed contingency specifications and required performance levels. In many cases the changes represent a very significant increase in required performance standards that will result in the following: a) major capital expenditures, some of which will be of a magnitude unprecedented for the Bulk Electric System. Many of these projects would be constructed to mitigate one single low-probability event. The ratepayers, upon discovery of this necessity and realization that these significant expenditures will be passed on to them in their rates, will certainly object to these efforts and will question the wisdom of NERC's mandating change on such a massive scale without the knowledge or input of the public. The SDT stated in its continent-wide conference call on October 10, 2007 that the intent of many of the objectives contained in the proposed TPL-001-1 was to "raise the bar" for electric utilities. We would like to know specifically what this means. The phrase "raise the bar" is vague and overused in North American vernacular in general, and it is particularly irresponsible to use such vagaries when proposing standards which will result in unaffordable upgrades to the North

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Commenter	**Yes**	**No**	**Comment**
			American Bulk Electric System. b) reductions in ATC. To be compliant with the more stringent requirements of TPL-001-1, Transmission Operators would in many cases be forced to reduce ATC in order to decrease transmission flows to a point at which corrective actions may be taken without the result of cascading. This is diametrically in opposition to one of the key objectives of deregulation and comparable treatment for all entities engaged in transactions on the Bulk Electric System. c) Reduced Reliability. The elimination of footnote (b) will result in many outage scenarios for which loss of Non Consequential Load is presently unavoidable, but subsequently prohibited. For some scenarios, Transmission Owners may seek to avoid the excessive cost of a project by simply removing breakers from substations, thereby increasing the range of the initial breaker-to-breaker operation and essentially converting the disallowed Non Consequential Load to Consequential Load. This is obviously an undesirable option and in opposition to fundamental principles of reliability, but might be rendered necessary due to the increased requirements of TPL-001-1. d) Inability to react to issues of non-compliance. The dynamic nature of planning analysis is such that, from one annual planning cycle to the next, the constantly changing load and generation forecasts invariably result in emerging transmission projects unforeseen in previous cycles. With the increased stringency of TPL-001-1, reacting to these emerging needs in time to demonstrate compliance will be impossible, and thus non-compliance is seen as an inevitability. To further clarify, the major transmission projects that TPL-001-1 would necessitate would be of a magnitude such that extensive engineering, land acquisition and involvement with regulatory and governmental agencies would be required, which could result in project lead times of 10 years or more. Not only would a lengthy transition period be needed for TPL-001-1, but upon the Standard's effective date the ability to implement all future projects would need to be given special consideration in light of these challenges. In other cases, the performance criteria are not clearly defined, such as the timing between multiple contingencies, and the level of readiness of the system before and after Planning Events. Finally, the SDT has chosen to eliminate the footnotes in the current standards, contrary to the direction of FERC in Order 693 to "clarify" the footnotes. The purpose of the footnotes is to further explain terms in the tables, provide guidance in interpreting the expected performance criteria, and specify any exceptions to the criteria. Footnotes also serve the purpose of keeping the standard concise by eliminating repetitiveness.

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Commenter	**Yes**	**No**	**Comment**
			Specific comments on the Draft Standard Performance Criteria 2. The performance requirements table should clearly define what the initial state of the system is assumed to be before any Planning Events, and what the state of the system is assumed to be after the Planning Event. For example, P1 (single contingency) events: assuming that the system is to be compliant, the state of the system prior to the event must be "secure" such that the event could occur and there is no interruption of firm transfer or loss of load, Equipment Ratings are not exceeded, System steady state voltages and post-transient voltage deviation are within acceptable limits. However, the system is not as it was before the event. The system could be described as "normal" but perhaps not "secure". If the requirement is that the system must also be "secure" after the event, then the standard must clarify what is allowed for "system adjustments" after the first Planning event to prepare for the next. FERC Order 693 directed the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency. However, in order to bring the system to a secure state, as is necessary for the second contingency of a category C3 or C5 event, footnote (c) allows curtailment of firm transfers, and FERC Order 693 only required footnote (c) to be clarify the term "controlled load interruption", leaving the curtailment language intact. The implication of this interpretation is critical to peninsular Florida. The Category B loss of one 500 kV line from Florida to Georgia is sustainable, such that the system is "normal" after the event. However, in order to be prepared for the next contingency, (the loss of the second 500 kV line), firm transfers must be curtailed (Interruption of Firm Transfer). Without the ability to curtail firm transfers, a "super-firm" priority of transmission service is created for non-native load customers, and thus comparable treatment no longer exists. Comments on New Performance Tables: The draft TPL standard represents a major change in the Table 1 contingency definitions and required performance levels. 3. Table 1 Contingencies C1 and C2 are being moved to the single contingency category. While C1 and C2 represent single element outages, their probability of occurrence is much lower than the other Category B contingencies and they do not belong in the single contingency performance requirements group. 4. Footnote (b) which permits, as a limited exception in unique circumstances with a sound rational basis, some localized load reduction for single contingencies, has been removed. This is a very significant change for some utilities. Footnote (c) which permits load shedding and curtailment of

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Commenter	**Yes**	**No**	**Comment**
			firm transfers has been removed from C1, C2 and most of C3. This is a very significant increase in required performance level that is not justified. 5. The "applicable rating" for loading and voltages in Table 1 has been removed so that essentially, the same ratings and voltage restrictions apply to both B and C contingencies. Some utilities plan to a normal rating for single contingencies but will allow a higher short term rating for Category C events. This practice appears to be either disallowed or inadequately described in TPL-001-1. Transmission Owners should allowed to base ratings on manufacturer specifications or other reasonable criteria using sound engineering judgment. 6. Several new Category D "Extreme Events" have been added which greatly expand the scope and complexity of Category D studies. These are (1) any two unrelated single element outages and (2) wide area events a. through h. These represent a major increase in the scope of Category D studies and probably a doubling of required SWG studies. It should be note that the existing Categories D1 through D4 have been substantially changed to eliminate analysis of relay failure contingencies. The philosophy contained in the existing TPL-004 standard is that faults with a protection failure should be evaluated whether that failure is a circuit breaker, relay or CT; the proposed standard restricts the analysis to breaker failure. 300 kV Threshold Performance Level 7. The TPL-001-1 draft sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Additionally, facilities above 300 kV naturally tend to transport larger amounts of power. The loss of single or multiple facilities above 300 kV generally results in an immediate generation-to-load mismatch too great to avoid either curtailment of firm transactions or loss of Non Consequential Load, or both. Singling out facilities above 300 kV for more stringent requirements is therefore clearly unreasonable. DC Line Performance Requirement 8. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie. With a parallel DC tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even

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Commenter	**Yes**	**No**	**Comment**
			cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities with less stringent requirements. Distinction Between Committed and Proposed Projects: 9. Models cannot discern the difference between a "committed" project, and a "proposed" project in a performance analysis. The standard should instead set criteria for when models can be relied upon for planning purposes such that changes to the future plan will not have an impact on reliability. The intent of Requirements R2.7.3 and R2.7.4 should be combined and added into R2.7.1.1. Rather than adding the additional requirement to document a criteria, the requirement should be that in the Near-Term Planning Horizon, projects cannot be removed (or modified) without demonstrating that the revised plan meets performance criteria. In addition, the requirement in R2.7.1.1 to supply a "project initiation date" is ambiguous. What will constitute "project initiation" …construction start date? …Engineering complete date? …Land procurement date? Funds allocated date (budgeted)? Suggested wording for R2.7.1.1. "Transmission and generation improvement projects for the Near-Term Transmission Planning Horizon, shall have in-service dates provided, and shall not have in-service dates changed, or be removed from planning models, without documentation to show that the revised plan meets performance requirements." Load Modeling Requirements: 10. The proposed TPL Standard contains numerous references to load modeling. The goal of improving and verifying the load model is worthwhile but is not appropriate for the TPL standards. Assessment of load model accuracy is best accomplished through detailed analysis of grid disturbance events. The main difficulties in accomplishing this are (1) grid events that significant reduce transmission voltages throughout a load area are infrequently occurring and (2) the process of recreating the event through simulation studies is extremely complex and time consuming. While these efforts should be encouraged they should remain a RRO prerogative. A few concerns not previously addressed by comments to Questions 1-42 include the following: R1.1.1 Use of expected Load mix - based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. – This requirement is not justified as the load model may be developed through disturbance analysis rather than load type synthesis by customer class. Some Load Serving Entities may have great difficulty in creating load forecasts based on customer class. Load forecasting requirements are adequately addressed in the existing MOD standards and do not belong in the proposed TPL standard. R1.2. Load models with supporting rationale - that include power factor data that may be based on historical System performance, validated by measurement during stressed System conditions, or

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			documented Transmission planning area requirements. This requirement is not appropriate for the TPL standards. 11. R.3.3.2.1. Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment. – this Requirement in its present wording could be construed to mean that the precise amount of load between breakers should be specified and reevaluated with every assessment. This would unnecessary and burdensome, and we therefore seek clarification of this Requirement or its removal altogether. 12. Requirements for studies using Sensitivity cases: R2.4.3 appears to place equal importance on base cases and sensitivity cases with regard to the need to implement projects or Corrective Action Plans. Terms in TPL-001-1 using forms of the word "sensitivity" need to be clearly defined by the SDT. Additionally, the SDT needs to clarify its intent regarding required action based on results from sensitivity studies. We do not agree that results from sensitivity studies should be given equal standing with results from base scenarios, and we would particularly object to any insinuation that projects would need to be implemented to mitigate violations seen in a sensitivity involving speculative non-firm transfers. 13. Short Circuit Requirements: The new TPL standard also contains numerous references to short circuit analysis, which are new requirements that expand the TPL standards, but without specific testing or performance criteria. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies. FRCC Specifics: One final specific issue concerns the topography and performance history of the Bulk Electric System in our particular region (FRCC). The FRCC system is a peninsular system having only one interface with the rest of the interconnected NERC system, and has historically demonstrated exceptionally high reliability with no events in recent history cascading beyond the FRCC system. While other areas of the NERC system may require some increased stringency in the TPL standards, PE feels that the adequacy of the existing TPL standards as they apply to the FRCC System has been extensively documented. Conclusion In conclusion, we believe that TPL-001-1 is unnecessary and burdensome. In particular, the

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			elimination of footnote (b) will deny Transmission Owners and Transmission Operators the right to curtail Non Consequential Load in order to restore the Bulk Electric System. This elimination has absolutely nothing to do with the reliability of the Bulk Electric System; rather, it places the reduction of Customer Minutes of Interruption (CMI) ahead of reliability. Essentially, the emphasis of TPL-001-1 is inappropriately placed on the reliability of distribution feeders rather than the reliability of the Bulk Electric System. The fundamental objective of the existing TPL Standards has been to protect the reliability of the Bulk Electric System, and we believe all future TPL Standards should do the same. Given the aforementioned issues, we believe the proposed TPL standard is inferior to the existing Board approved TPL Standards, creates unnecessary confusion, and will require many iterations of industry comment and revision. As an intermediate approach, we would strongly urge the Standard Drafting Team that the existing TPL standards be modified to respond to FERC Order 693 directives, clarify any ambiguities, and that the proposed new standard not be pursued any further.

Response: 1. The SDT followed the suggestion of FERC in Order 693 to consolidate the 4 standards into 1 if possible. The SDT recognizes that it has it has raised the bar on performance in some areas and has done that due to criticisms and suggestions from various parties. The SDT realizes that this will have an impact and is working on an Implementation Plan that will address some of the concerns. This is a performance based reliability standard and does not and should not consider economics. The SDT has made numerous changes to the tables in an attempt to provide further clarity as to what needs to be done to achieve performance.
2. An Initial Conditions column has been added to the tables. The SDT has also changes several requirements in the tables to allow for more instances of where Load can be dropped.
3. The SDT studied available data and practices and determined that these Contingencies do belong in the single Contingency performance group.
4. Local Load pockets are recognized as a problem and the SDT will address them in a future revision.
5. The use of the defined term Facility Ratings was intentional to answer problems such as described here.
6. The SDT was responding to FERC Order 693 in the details for Extreme Events.
7. The SDT feels that 300 kV and above represents the backbone of the BES and as such warrants more stringent criteria.
8. This is the only comment received on this issue so no changes were made to the second revision of the standard. However, the SDT will continue to review the performance table in subsequent revisions.
9. This verbiage has been removed from the standard.
10. The SDT feels that the current MOD standards do not cover all of the modeling requirements for a planner. Therefore, the specific areas found lacking are described in the TPL standard. Once the MOD standards are revised appropriately, these requirements can be deleted from TPL. The SDT has re-written these requirements and they are now numbered Requirement R9 through R13.
11. R3.3.2.1 - FERC required documentation of Consequential Load loss in Order 693, paragraph 1795, (not Non-Consequential) and duration should be based on best judgment for the common cause of the event.
12. Addressing or not addressing deficiencies discovered as a result of runing sensitivity studies is at the discretion of individual entities. The language of the standard has been changed to require that the entity document why or why not the results of the sensitivities have affected the Corrective Action Plan.

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13. Short circuit studies are required as part of the Interconnection process. The TPL draft addresses on-going System changes and increases in available fault current due to the additions of circuits and resources, as listed in the Corrective Action Plan. Short circuit studies help determine appropriate equipment sizing and setting of protective relays. Such studies will help provide for a complete Corrective Action Plan, i.e., the installation of a transformer to resolve a System performance deficiency may require the installation of additional circuit breakers. FERC also noted the need to include this analysis to cover such conditions. The SDT has thoroughly considered the comments of all reponders. We believe that the revised draft of TPL-001-1 places the proper focus on BES reliability and the BES' mission to serve all firm Load under an appropriate range of Contingency events. Furthermore, the SDT believes that the current draft does in fact respond to the FERC Order 693 directives.			
ReliabilityFirst	☑		The requirement for short circuit studies (mentioned in R2 and included in all of R2.3) should be removed from this standard. Relay and protection engineers use a different type of software (Aspen and CAPE) for different reasons (to calculate phase and ground faults and perform relay coordination studies). Those types of studies should not be included in this standard and are totally separate from performing power flow and dynamics studies.
Response: The SDT believes that it is appropriate to include an assessment of the results of short circuit studies in the assessment of the reliability of the Transmission system. The standard does not specify requirements related to software or specific requirements of the studies.			
SRP	☑		The SDT should be commended for very good work at identifying many different issues of the TPL standards. However, TPL-001-1 should take into account the consequences of a Security-Based or Dependability-Based Misoperation (and failure) of the Protection System. 1) A Security-Based Misoperation of the Protection System may remove additional elements of the BES and could be listed in the table under "multiple contingency". 2) A Dependability-Based Misoperation (or Failure) of a non-redundant Protection System could cause long time delays in clearing faults and clear a large area of BES around the faulted Element. This type of failure may not provide local tripping or breaker failure initiation and remote Protection Systems would need to operate to isolate the fault or disturbance. Often the operation of the remote Protection Systems would cause long time delays in isolating faults and disturbances. a) The BES should be studied and those elements need to be identified where Dependability-Based Misoperations (or failures) would prevent meeting the performance requirements of Table 1 (Steady State) or Table 2 (Stability). This type of Misoperation (or Failure) will have to be included in the Tables. For example, some parts of the BES may be able to survive long time delayed clearing of faults caused by Dependability-Based Protection System Misoperations (or failures) and still meet the performance requirements of the tables. But other parts of the BES may experience cascading outages for this same scenario. One solution to minimize the consequences of Dependability-Based Misoperations (or failures) is to install redundant Protection Systems. The redundant Protection Systems would reduce the possibility of a single Dependability-Based Misoperation (or failure) from

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Commenter	**Yes**	**No**	**Comment**
			affecting the isolation of faults and disturbances. In addition, the TPL-001 standard will need definitions of Security-Based Misoperation and Dependability-Based Misoperation. The following definitions are used for PRC-004-WECC-1: Security-Based Misoperation: The incorrect operation of a Protection System or RAS for faults or disturbances outside the intended zone of protection. Security is a component of reliability and is the measure of a device's certainty not to operate falsely. Dependability-Based Misoperation: Any of the following ▪ The absence of a Protection System or RAS operation when intended ▪ A Protection System or RAS equipment failure is alarmed or indicated to operating personnel. ▪ A Protection System or RAS equipment failure is discovered. Dependability is a component of reliability and is the measure of a device's certainty to operate when required.
Response: To date, the SDT has done the following: Tables 1 and 2 have been revised. A Contingency involving the failure in the Protection System has been added as P5 in Tables 1 and 2. Also 2a-2d were added in the Table 2 Extreme Events. The SDT is continuing discussion on Protection System issues and will be making additional changes as appropriate in future versions.			
Santee Cooper	☑		1. Transmission Planners are currently able to maintain adequate levels of reliability using the existing TPL-001 thru TPL-004 standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will result in significant reliability improvements. 2. Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints. 3. There are no explicit performance requirements for normal system performance. 4. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The standard and the ERAG MMWG need to be made consistent. 5. Requirement R2.3 There are no performance requirements for Short Circuit Studies. 6. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes.

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			7. Requirement R3.2. There should be some flexibility for simulation of planning events. For certain areas of the BES, the resulting configuration after operator intervention could be more severe than the removal of all elements. For example, the operation of a transmission line with one end open may be more severe than opening both ends of the line. This respresents actual operation in order to restore service to stations on the line. 8. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 9.Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 10. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state. 11. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 12. Requirement R4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 13. The R1 requirements should be deleted from this standard and should remain on the MOD standards. (MOD-010, MOD-012, and MOD-018) 14. Requirement R4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 15. Requirement R4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The

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			identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 16. The standard needs to define or describe the difference between a "bus" and a "bus section". 17. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare? 18. The use of the terms "bus", "non-tie bus", and "bus section" are not clear. In P7-2 what is meant by the phrase or a bus and a stuck non-bus tie breaker ? Does this imply a bus or a bus section? How would you model this?

Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.
2. The term "firm transfer" in Tables 1 and 2 has been replaced with "firm Transmission service".
3. Table 1 has been revised to include normal System performance requirements.
4. This requirement has been eliminated in response to various industry comments.
5. Short circuit duty is a Facilitiy Rating, and Facility Ratings shall not be exceeded.
6. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
7. R3.2 - The SDT has added a line end open condition in P2.
8. R3.3.2.1 - FERC has jurisdiction over firm Transmission service. FERC allows the use of "equally or more efficient or effective approach" and firm Load is being used as a proxy for firm Transmission service.
9. This requirement is consistent with FERC Order 693.
10. The SDT agrees that SPS can include generation tripping. The SDT has modified the requirements to allow SPS for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met:

11. The SDT feels that the wording is equivalent.
12. The answer is yes it does.
13. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.

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Commenter	**Yes**	**No**	**Comment**
14. The SDT feels that the wording is clear as stated. 15. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 16. "Bus section" is in the existing TPL standards; the SDT is not proposing to change its meaning. The SDT considered but has decided not to include a definition for "bus section". 17. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 18. The SDT has included a definition for Bus-tie Breaker. The SDT has clarified the event description for P7-2 (now P-4 in the second draft). **Bus-tie Breaker:** A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)			
SaskPower	☑		Saskatchewan commends the SDT for taking on this difficult and important task. We wish you good fortune. 1. Local area network load is allowed to be shed in Saskatchewan for single contingencies, and the interruption of firm transfers are allowed over our DC tie and AC tie-lines. The Saskatchewan Regulatory Jurisdiction has no plans to change this unless there is technical evidence to justify the increase in reliability versus the cost. 2. Also for P9-1, is there any justification for the selection of one mile? If there is none the development of exemption criterion should be delegated to the Planning Coordinator. It is not what Saskatchewan has used in designing its system, and it is going to involve a significant capital outlay for Saskatchewan with questionable reliability benefits. Saskatchewan will not support the default value of 1 mile unless there is a technical study (including reliability benefit versus cost) to support it as opposed to any other distance.
Response: 1. The SDT is required to address FERC Order 693 and cannot default to lowest common denominator. This issue is beyond the scope of the SDT and needs to be addressed at the NERC level. However, an Entity can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27). **2.** The one mile allows for some measurable physical constraints to building separate lines in all locations, but limits the exposure to a fixed length, which is universally applicable. SaskPower can request an "Entity Variance" in accordance with the NERC Reliability Standards Development Procedure (Page 27).			
Seattle City	☑		The additional studies required by this proposed standards are going to put a burden on our utility. We do not have the additional human resources available to perform so much additional work. Also, the stipulation that no "non-consequential load" loss may occur will put a financial burden on our utility. We have always planned assuming that we would able to be shed residential load in case of

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			an emergency caused by a N-2 event or regional outage beyond our control.
Response: The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability.			
SERC EC DRS	☑		1.In the Stability Performance Table, under contingency P8 with a line out add a generator contingency. and with a transformer out add a generator and a line contingency. 2. In the Stability table change the Extreme Events numbering to E1, E2, etc. 3. In R4.6 and other locations, the generator exemption of 20 MW should be increased to 75 MVA.
Response: 1. The transformer – line combination has been added. The SDT does not feel that the other cited events are a legitimate combination. If you have specific data to indicate otherwise, please provide it. 2. The SDT made changes to the format of Extreme Events. 3. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
SERC EC PSS	☑		Significant Increase in Study Activity Workload on Transmission Planners: 1. The increase in both steady state and dynamic studies required to ensure compliance with the proposed standards will result in increased costs and staff additions. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. Additionally, experienced staff capable of performing analyses as described in the proposed standard have become increasingly difficult to find and retain and the talent pool of people with these skills has recently become depleted to alarming levels. Implementation Plan: 2. Given the intent of the proposed standard to encourage large scale investment in the EHV system, full implementation will take years, perhaps decades. Acquirement of right-of-way for new EHV lines has become increasingly difficult in recent years and inreasingly expensive. Legal, regulatory, and other difficult issues often take several years to navigate, even for 115kV lines. The Implementation Plan timeframe, if set too short, would be unduly burdensome on Transmission Owners forcing them to be less dicretionary with funds than would be prudent. The proposed implementation plan should include provisions for those cases where viable solutions simply can not be implemented in time due to circumstances beyond the control of Transmission owners. We recommend a minimum of 15 years for the transition. Design and Construction Constraints: 3. Even if right-of-way and other legal and regulatory hurdles are cleared, and the capital funding for such a tremendous level of investment was not an issue, the other resources required to actually

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			construct the projects are equally difficult and costly to secure. Raw material prices on comodities like copper and steel have skyrocketed in recent years. Additionally, the skilled labor and Engineering resources are constrained with labor rates almost keeping up with other resource costs. Overall project costs have more than doubled over the last 7-10 years. Recent press releases concerning new generation being planned and then scrapped due to the rapid escalation of project costs are public evidence of this. The inflationary mark-up is impossible to estimate but much less will be built with the same capital investment than is currently envisioned. Cost-Benefit Analysis: 4. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures certain under the proposed standard. Additionally, as many jurisdictional rate structures share the cost of such investments between retail and wholesale customers, cost-benefit analyses should be completed for both retail and wholesale customers. System Adjustment Clarification: 5. The term "System Adjustment" as outlined in the tables should be better defined. The use of generation for redispatch may have nuances which preclude or otherwise limit their use for studies. Perhaps some clearer guidelines on what is allowed would facilitate transparency and coordination between Transmission Planners. Transmission Service Evaluation: 6. A major concern is that the proposed standard appears to be disjointed from the requirements for selling firm Transmission Service. The increase in reliability gained from the proposed standard would, in some regions, quickly be eroded by new firm sales if those sales are based on the historical N-1 ATC requirements. The proposed standard must be applied to long-term firm transmission service requests if Transmission reliability is to be truly enhanced. If the standard is not applied to Transmission Service evaluation, reliability levels for the different classes of firm customers will diverge.
Response: 1. The SDT understands the potential increases in work load. The draft standard allows the use of past studies to meet the current year assessment and study requirements. Requirement R3.2 does not require study of the protective scheme for all events, only that "Contingency analyses shall simulate the removal of all elements including those that System protection is expected to disconnect for each Contingency without operator intervention". For example, the requirement is that the outage simulation should be from breaker to breaker. In addition, Requirement R.3.2.2 only requires the studies consider relay loadability and identify how loadability is treated in the steady state simulation, not to study relay loadibility. 2. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new			

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Commenter	**Yes**	**No**	**Comment**
standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. 3. The SDT understands that there are extended transitionary issues associated with responsible entities becoming compliant with the new standard. The SDT plans to draft an extended implementation plan to accommodate such issues. The plan will be provided for the third posting of the standard. Cost issues are outside the scope of NERC reliability standards. 4. The treatment of Transmission infrastructure costs is outside the scope of the NERC reliability standards. 5. The Transmission performance tables have been modified to bring clarity to the Contingencies required for performance studies and when Non-Consequential Load Loss is permitted to meet requirements. The use of manual or automatic System adjustments to revise System topology as well as generation redispatch is always permitted so long as the actions can be performed while adhering to Facility Ratings. 6. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
SERC RRS OPS	☑		Cost-Benefit Analysis: 1. Transmission Providers are currently able to maintain adequate levels of reliability using existing standards. While incremental improvements can be made, it is not evident that prescribing more stringent planning requirements will necessarily result in significant reliability improvements. 2. The proposed standard will be exceedingly expensive to become compliant with unprecedented levels of capital investment in Transmission facilities. Before the standard comes to official vote, it would be prudent for a cost-benefit analysis to be performed to determine if the reliability improvements truly justify the huge expenditures under the proposed standard. 3. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistent with the requirement to re-dispatch to address system constraints. 4. The terms "Consequential Load Loss" and "Non-consequential Load Loss" should be deleted and Table 1 should be modified to discuss "Planned Load Loss" and "Unplanned Load Loss". It should not matter if the load is directly connected to the failed facility or downstream and served by the failed facility. If the plan to protect the interconnected grid is to disconnect those loads using a manual process or an automatic scheme, then it should be allowed. 5. The R1 requirements should be deleted from this standard and should remain in the MOD standards.
Response: 1. The SDT believes that more stringent planning ("raising the bar") is appropriate in some areas of the standard and will improve reliability. 2. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under			

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Commenter	**Yes**	**No**	**Comment**
consideration. 3. Tables 1 and 2 have been revised to replace the term "firm transfer" with "firm Transmission service". 4. The SDT feels that the terms are being used consistent with FERC Order 693. 5. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.			
SCE&G	☑		General Comment. 1. Cost/Benefit analyses should be conducted on each change in a standard or new standard. 2. Requirement 7.2 will require a 2 bus outage test on the SCE&G transmission system. Most of our busses are straight busses and a stuck line-terminal breaker will result in a clearing of the connected bus (and all facilities connected to that bus). Our read of this requirement is that we must design the system to accommodate a stuck breaker event (outaging all connected facilities) while a different bus (and all of its connected facilities) is already outaged. This is a significant leap in the required performance of our system and will result in tremendous unwarranted costs and years of new local area transmission construction. 3. Requirement R1.1.2 refers to "normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s)…" The ERAG MMWG considers normal weather to be such that the weather affected load to be that which has a 50% probability of, plus or minus. The standard and the ERAG MMWG need to be made consistent. 4. Requirement R2.7.1.1 specifies a "project initiation date". This information is not needed for system reliability purposes. 5. Requirement R3.3.2.1 requires an evaluation for "Consequential Load loss (expected maximum demand and expected duration). Load loss is not an ERO responsibility. 6. Requirement R3.3.2.2 does not permit the "shedding of firm Load or curtailment of firm transfers". This is not an ERO responsibility. 7. Requirement R3.6 states "Manual and automatic generation tripping is allowed for multiple Contingencies and for single Contingencies only in situations that meet all of the following conditions: TBD. Generators should be allowed to trip for single and multiple contingencies as long as Facility Ratings are not exceeded. In addition, generators should be allowed to trip for any condition that imperils the generator. System performance should be the criteria, not generator operating state.

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Commenter	**Yes**	**No**	**Comment**
			8. Requirement R4.2 states "Contingency analyses shall simulate the removal of all elements including those that the System protection is expected to disconnect for each Contingency without operator intervention." Delete "including those". 9. Requirement 4.6.1 states that Plant Stability studies "Shall be performed for individual generating units 20 MW or greater…" Does this mean that studies must be performed for all units? Many plants have "sister units" that are essentially the same. This requirement seems to be excessive. 10. Requirement 4.6.2 states that Plant Stability studies "Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater." The meaning of this wording is unclear. 11. Requirement 4.6.3 states that Plant Stability studies "Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results. The identified Contingencies, at a minimum, shall be evaluated." The use of "evaluation/evaluated is unclear. Is an evaluation the same as performing a study? If not, what does it mean to select a contingency for evaluation? 12. The standard needs to define or describe the difference between a "bus" and a "bus section" and ensure that the use of these terms in the standard are as intended. 13. Table I, P3, P7.2, P9.6 and Table 2, P7 need some punctuation for clarification. 14. Table I, P9.6 and Table 2, P9, why study replacing an outaged transformer with a spare?

Response: 1. Any changes in the new draft Standard have been carefully weighed and discussed by the SDT. The SDT does not believe that a formal cost benefit analysis is required. However, if you have cost data which you would be willing to supply to the SDT, we will take it under consideration.
2. The SDT feels that this requirement is appropriate for a North American standard. The eventual Implementation Plan will address the timeframe for compliance.
3. This requirement has been eliminated in response to various industry comments.
4. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review within the NERC community and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them.
5. The SDT disagrees. FERC Order 693, Paragraph 1794 specifically prohibits loss of Non-Consequential Load for a single Contingency. Furthermore, FERC required documentation of Consequential Load loss in Order 693, paragraph 1795.
6. R3.3.2.2 - R3.3.2.2 has been revised and the phrase "shedding of firm Load or curtailment of firm transfers" has been deleted.

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Commenter	**Yes**	**No**	**Comment**
R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 7. The SDT agrees that generation tripping can be included. The SDT has modified the requirements (See Requirement R 3.5). **R3.5.** Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~ if the following conditions are met: 8. The SDT feels that the wording is equivalent and no changes are necessary. 9. and 10. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria. 11. Evaluation is based on good professional judgment and knowledge of the System. It is not the same as a study. 12. The SDT considered but decided against adding a definition because the term "Bus Section" is in the existing TPL Standards and its meaning is generally understood. 13. Tables 1 and 2 have been revised. 14. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11.** Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information.			
Southern Transm.	☑		REQUIREMENTS: 1. The standard is not clear on whether corrective action plans are required for performance failures during the sensitivity analysis required for both steady-state and stability studies. In the phone conference John Odom stated that it was not the intent of the Drafting team to require that facililities be constructed for these conditions. The standard should be made clear on this point. 2. The Load Forecast section (R1.1) is new and is a duplicate of the requirements in the MOD standards and is unclear as written. Having similar requirements in multiple standards creates the possiblility of conflicting requirements for the industry. If there are different requirements necessary, the MOD standards should be modified and not introduce a new section to the TPL standards. 3. R1.1.1 is unclear in what is intended by the "actual or expected aggregate mix of industrial, commercial, and residential load". Does the word "aggregrate" mean that the split between customer classes should be at the Balancing Authority level or at each load bus represented in the model. In many cases this could place a requirement for substantial load research on the the industry which may take a substantial amount of time and expense to accomplish. The use of the phrase "actual or

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Commenter	**Yes**	**No**	**Comment**
			expected" indicates an expectation that it be based on research and not general industry averages as may be more practical in some cases. 4. The wording in section R1.2 is very unclear. Is the intent to allow for three different methods for obtaining power factor models, i.e. historical system performance, validated by measurements during stressed System conditions, or documented Transmission planning area requirements? The other understanding is that the historical System performance is only measured during stressed System conditions. If this is the intent, what is the definition of stressed system conditions that is intended? Is this just heavy loadings, such as peak times, or is it during sytem disturbances? This is not clear. We suggest that the following words be used instead: "Load models validated by measurement during load levels typically studied or documented Transmission planning area requirements." 5. Requirement R1.4 should be qualified as only the outages within the Planning Horizon. There is no need to include protective relays because outages of relays in the Planning Horizon would not be known. We suggest the following words: "Known planned outages within the Planning Horizon and long-term outages greater than one year within the Planning Horizon for Transmission and generation equipment with consideration given to spare equipment strategy." 6. R1.5: If this places a requirement on the PC to define what constitutes "planned facilities", then this should be explicitly stated as a requirement. 7. R2.1 allows Assessments to be supplemented with "qualified" past studies which are defined in R2.6. R2.6.1 specifies these to be less than three years old for steady-state analysis and certain changes could not have occurred in the "System". There should be some qualification to the definition of "System" to include "the vicinity" of the area under evaluation. We would surmise that there always be some change in topology in the Eastern Interconnect which would preclude the use of past studies. Note that the "in the vicinity of" wording is used with the plant stability studies already. Also, is the intent with the "less than" to eliminate the use of studies three years old? Similar comments can be made for R2.6.2 and R 2.6.3. 8. R2.1 The wording/structure is confusing. The "Planning Assessment shall address all five years", but this does not require all five years be studied. It appears that the minimum study requirements would be two peak studies (years 1 or 2 & 5), one off peak study (any year), and one senstitivity case for each. Is this a correct reading? 9. In R.2.1.3.1 it is unclear what is intended. The study can be for higher or lower load "forecasts" with a different load power factor due to season, weather, or time of day. If you are looking at different seasons, weather, or time of day you will have a different load forecast. Is the intent to

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Commenter	**Yes**	**No**	**Comment**
			require the studies to model different seasons or times of day that will generate different power factors or is it to focus on higher or lower loads, i.e. is it a load forecast exercise or a power factor exercise? Can we look at Spring conditions and have it qualify for this requirement even though the loads are consistent with my Base Case load forecast? 10. Requirement R2.1.3.3 lists "unavailability of long lead time facilities" as one of the sensitivity(ies) that should be evaluated. It is unclear whether this refers to the construction of projects with long lead times or for replacement of failed equipment that have long lead times for obtaining replacements. One of the drafting team members suggested it was the latter understanding that was intended. We suggest that the language be changed to "Delayed restoration to service of failed facilities with long lead times for repair". This may clarify the intent of the requirement. 11. R2.1.3.7 should be modified to read "Modification of planned long term Transmission outages." 12. R2.3.1 Does "current study" refer to an updated study or is this referring to some type of short-circuit analysis? It appears that analysis is required only every five years unless changes in the BES occur. Is this a correct reading? 13. R2.4: Need to clarify that "address all five years of the assessment period" does not necessarily require that each year must be studied individually. A study of one year could cover all 5 years if it is the worst case. 14. R2.4.3.2 Is the purpose of including non-firm transfers to identify generation limits? Please clarify that the intent is not to require constraints associated with non-firm transfers to be addressed. 15. R2.5.2: The addition of a transmission line always helps plant stability. Therefore, this should not be included as a change requiring a new study. 16. R2.7.1.1 requires that the action plan include a project initiation date as well as the in-service date. The project "initiation date" is not defined and can be interpreted as being when you thought up the project, when you started spending money on design, or when you actually started construction. As long as you have the in-service date when the project is needed, we do not see any major benefit from recording and documenting an "initiation" date. The length of time that it requires to complete a project is extremely variable based on many conditions so we're not sure what benefit, if any, will be gained by recording and documenting the initiation date. It may be impossible for someone not familiar with the legal, regulatory, etc. requirements in a given area to judge whether the timing is appropriate or not. This requirement should be eliminated.

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			17. R2.7.5 calls for the review of the implementation status of facilities. This imposes a large documentation requirement which has no benefit in reliability. We suggest making this requirement on an "as requested" basis. 18. Requirements 3.2 and 4.2: Delete the words "including those" so that it reads "the removal of all elements that System protection is expected...". As currently written, it sounds like you are going to remove more elements than the protection will remove. 19. R3.2 requires that the contingency analysis shall simulate the removal of all elements including those that System protection is expected to disconnect for each contingency without operator intervention. At present most steady state analysis uses single "element" contingency with element defined as transmission lines or transformers as defined in the Power Flow cases. In a significant number of cases these individual "lines" are part of a larger "protection control group" (PCG). that would remove multiple elements encompased by the breakers in the PCG The present load flow tools (PSS/E) do not have features that will allow this type of analysis in an automated manner. To facilitate this change in required analysis, program modification will be needed or additional programs written. For an example with a line from bus A to B and then B to C with breakers at A and C and load at B, the outage of either A to B or B to C with load service remaining at Bus B may produce a more stringent condition than removing A to B to C. It appears that the new requirement is requiring the A to B to C analysis instead of the more stringent A to B or B to C. 20. Requirement R3.2.1 is unclear. Generators generally have both a high and a low voltage limitation on the terminal voltage related to station service reqirements. Most load flow representations for generators tend to hold the voltage on the high side of the GSU instead of the low side. Is this requirement attempting to say that the voltage limitations on the generator terminals must be considered or is it something else? This should be made clear in the requirement. 21. R3.3.2.1 requires that the amount of "consequential Load loss following a single Contingency shall be identified and the anticipated duration be recorded". This is an arbitrary requirement that will require significant time and effort to document and will provide no useful information from a planning perspective. Also the inclusion of an "expected" duration is more arbitrary than the actual amount of load. The time required to restore the facilities is a pure guess at best since it will vary substantially based on circumstances and conditions. Since we are also required to remove all elements that the protection control group (PCG) will open instead of just a single "power flow model" line, some of the load may be restored during switching action for tapped loads and some may not. This creates an additonal confusion of what is required to be recorded in terms of duration and load reduction. We see no benefit from identifying and documenting either the amount of consequential

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Commenter	**Yes**	**No**	**Comment**
			load lost or the estimated duration that would justify the time and effort required. 22. R3.3.2.2 This states that curtailments of firm transfers are not permissible following single contingency events to meet the performance criteria. Please clarify whether "firm transfers" refers to firm point to point service only, or if firm network service is also included. Said another way, is the curtailment of a network resource permissible following single contingency events to meet the performance criteria? If not, please clarify how redispatch service as required by Order 890 should be considered. If curtailment of a network resource is permited, please clarify why curtailment of PTP would be held to a higher standard. Also, please clarify whether R3.3.2.2 applies to P6. Lastly, please clarify how Conditional Firm Service (CFS) as required by Order 890 should be considered in meeting R3.3.2.2. CFS allows the curtailment of "firm" PTP transfers. This appears to be in conflict with the performance criteria. 23. Requirement R3.6 is not clear. It could be interpreted as generator tripping allowed for multiple contingencies only for the situations that meet the "to be determined" conditions. Generator tripping should always be allowed for multiple contingencies. 24. R4.5 and R4.6: We suggest dropping the words "For the" in each of these. 25. R4.6.1: Plant stability studies should not be required for generating units as small as 20 MW. The threshhold should be 100 MW or greater. 26. R4.6.3: The last sentence "The identified Contingencies, at a minimum, shall be evaluated" is redundant because the requirement already says "shall be performed and evaluated" The last sentence should therefore be deleted. TABLE 1 - STEADY STATE PERFORMANCE: 27. In Table 1 in the column titled "Interruption of Firm Transfer Allowed," does it pertain to point-to-point only, or does it also apply to network loads? Please explain how this provision is consistient with the requirement to re-dispatch to address system constraints. 28. Steady state table, extreme event description, section 3: Items d and f are operating issues and therefore should not be included in the table. Also, items c and d are identical. Items d and f are identical. 29. Steady state table: Add the requirement to study n-0 to the table so it will be complete. Call it P0.

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			30. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 31. Steady state table: For the event in P3, it is not clear what the "above 300 kV" applies to. Is it only the transformer? Or it it also the transmission circuit and generator? Also, the third column mentions DC when there is no DC in the event. 32. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 33. Steady state table: For transformers below 300 kV, P9.6 is no different from P8.3. We suggest adding the clarification of "above 300 kV" for P9.6. 34. Steady state table Extreme Event: 3.b "A successful cyber attack" needs to be clarified. What should the contingency be? 3.g Add the words "As applicable" to the beginning. 3.h This should be changed to "Other events as deemed appropriate by the PC based upon operating experience". Otherwise there will be no end to the contingencies that must be studied. 35. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 36. Steady State Performance Requirement, Table 1, Performance Levels P1-P4, should allow for the interruption of firm transfers if the transfer is dependent upon on the outaged equipment (whether AC or DC) to provide an electrical path specified in the transfer. Therefore, the current verbiage used for the outage of a DC Line should be applied to all levels and state, “Yes, if transfer is dependent on the outaged equipment to provide an electrical path for service” 37. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated".

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			TABLE 2 - STABILITY PERFORMANCE TABLE: 38. Stability table, note 1.a.i: P3.2 should be P2.3. 39. Several events in the tables use the term "internal fault" for a breaker. The SDT needs to explain what is intended by this term. 40. In event P7.2, does the "below 300 kV" apply to the generator, transmission circuit, transformer, and bus as well as to the stuck breaker? Or does it apply only to the stuck breaker? 41. The event description in P3 is confusing. Please consider rewording in the 1,2,3 format of the other event descriptions. The term "non-bus tie breaker" is confusing. Please consider using "breaker (excluding bus ties)". Also, above 300 kV, most construction is either ring bus or breaker and a half. Please considered deleting the bus outage contingency. Lastly, please clarify how redispatch and CFS should be considered in the context of P3 and P4, in which the curtailment of firm transfers is not permissible to meet the performance criteria. 42. Steady state table and stability table: Change the heading which now says "For all Planning Events" to say "The following performance requirements must be met for the Planning events evaluated in addition to the requirements given in the columns" 43. Steady state and stability tables: in the Extreme Events section heading, the word "all" implies that all events must be evaluated when this is not the intent. Either make the heading "For Extreme Events" or make it "For all Extreme Events evaluated". 44. Stability table, footnote 1.a.ii. After "out-of-step protection", add the words "or some other means to trip the generator for this condition". GENERAL: 45. The overall level of documentation required by this standard is excessive.
Response: 1. The SDT is providing some guidance under Requirement R2.1.3 on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. It is the entity's decision to establish and document which transfers are more significant to study System responses. Requirement R 2.7.2 has been added to require a description of how and why the list of actions was modified and/or expanded as a result of the inclusion of the sensitivities selected. The SDT fells that the standards are clear that the sensitivity studies do not in themselves establish the need for a plan, only the areas of the System for which the analysis is needed.			

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R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation ~~with~~ of the technical rationale for ~~the selected sensitivity(ies)~~ why each of the conditions was or was not selected shall be supplied:

R2.7.2. ~~Be added to study cases and the cases re-tested to show that the System with planned additions meets the performance requirements in the tables~~ Contain a description of how and why the consideration of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 in the Planning Assessment did or did not result in a modification or expansion of the list of actions developed in accordance with Requirement R2.7.1.

2. The SDT believes some additional modeling requirements not presently contained in the MOD standards are necessary for Transmission planning purposes. The SDT has revised these requirements based on industry comments to eliminate redundancy with existing MOD standards with the intent that these requirements will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.
3. The terms "actual" and "aggregate" have been deleted. However, the SDT believes the term "expected" allows for flexibility in determining the necessary modeling information.
4. The SDT's initial attempt was to allow any of the three methods listed for obtaining power factor models. The SDT has removed Requirement R1.2 from the draft and replaced it with a new Requirement R9 in the revised draft to have the Distribution Provider provide real and reactive Load forecast data based on expected or historical system performance.

R9. Each Distribution Provider shall provide its respective Planning Coordinator with modeling information for real and reactive load forecast data for each year of the Transmission planning horizon at Transmission nodes based on expected or historical System performance including the expected mix of industrial, commercial, and residential Loads, within ninety days of a request for such information.

5. The SDT has revised this requirement based on industry comments to delete the reference to "protective relays" and to clarify the intent that *known* planned outages and long-term outages for Transmission equipment, including the impact of spare equipment strategy, be considered, and to be responsive to FERC Order 693, paragraph 1725.
6. The referenced verbiage has been deleted from the revised standard.
7. The intent of the requirements was to put an upper bound on the shelf life of the study and bracket the applicability of the study such that, if changes were made that may effect results of the previous studies, they shouldn't be used. The SDT agrees with your comment and clarified the wording in Requirements R 2.6.1, 2.6.2, and 2.6.3.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.

R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study

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area.

R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator~~

8. You are correct. The standard does not require that all 5 years be studied. The standard only requires that the assessment address the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the system can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
9. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. Requirement R2.1.3.1 provides the flexibility to allow the planning entity to decide how a variation in load on the entity(ies) system should best be studied. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determine the actions necessary to handle such items and which are more significant to study system responses.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied:

R2.4.4. In addition to those sensitivities mentioned in Requirement R2.4.3, any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems, shall be run and documentation of the technical rationale for why each was selected shall be supplied.

10. The SDT is providing guidance regarding the sensitivity studies while not being totally prescriptive. Requirement R2.1.3.3 provides the flexibility to allow the planning entity(ies) to elect the type of long lead time project that should be included in the analysis. It can be either a long lead time from replacement for failed equipment or a long lead time associated with constructing a new facility. Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies. Requirement R2.4.4 has been added to specifically state that the entity may consider additional sensitivities that are appropriate for its own System. In either case the entity must document the reason for running or not running cases for the items listed. The documentation as well as the studies for the sensitivity(ies) selected will be required to demonstrate compliance. It is the entity's decision to establish and document if it needs to consider future additions and retirements. It is the entity's responsibility to determene the actions necessary to handle such items and which are more significant to study system responses.
11. Since this requirement is relating to sensitivity, it is up to the entity to determine if it is appropriate to reduce the length of or increase

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the length of the "planned outage" that it has considered in its base case studies.
12. In the standard, "current study" is intended to refer to an updated study (i.e., as opposed to a "past study"). The SDT received comments that "current" study could be misconstrued in reference to short circuit "current" (amperes) versus the intended meaning. The SDT revised the standard in an attempt to clarify the intent. A current study will need to be performed as part of the annual Assessment if there are changes warranting one. Until such time as a BES change occurs, studies have to be refreshed at least every five years.
13. The use of the terms "shall address" is trying to convey that message, the requirements detail the studies needed.
14. R2.4.3.2 - Non-firm transfers are included in Requirement R2.4.3.2 to be investigated as sensitivity. The second draft of the proposed standard clarifies in Requirement R2.7 that the corrective actions do not need to be developed solely to meet the performance requirements for sensitivities.

R2.7 - For Planning Events shown in Table 1 – Steady State Performance and Table 2 – Stability Performance, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed ~~over time~~ in subsequent assessments but the System shall continue to meet the performance requirements in the tables. ~~Such plans shall:~~ Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities.

15. The language was changed to reflect this comment.

R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the addition of a new substation in one of the Transmission Lines connected to the plant.

16. Requirement R8 (old Requirement R6) which focuses on the distribution of the Planning Assessment results among affected entities was specifically added to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Requirement R2.7.1.1 is complementary to Requirement R8 (old Requirement R6). Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. Typically the date would indicate when significant resources will begin to be employed. This covers any project proposed for the near term. The SDT continues to believe that by providing the expected project intiation date of System improvements provides useful information to neighboring entities. The SDT believes that initiation dates are required for near-term corrective action plans to give an indication that the corrective action plans can be implemented in time.
17. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project.
18. Based on industry comments, the language referenced in this comment was retained but modified in revised Requirement R5.2 to clarify intent.

R5.2. Contingency analyses shall simulate the removal of all elements including those that System protection and other automatic controls are ~~is~~ expected to disconnect for each Contingency without operator intervention.

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Commenter	**Yes**	**No**	**Comment**

19. There may also be the case where the outage of A to C overloads a parallel circuit whereas having the C to B line is service does not overload the parallel circuit. The outage of the A to C line by automatic interruption is the more realistic outage because of the interrupting devices on the ends of the line. Both conditions are now covered in Table 1 and Table 2.
20. Most commenters did not express confusion over this requirement, so it was not modified. Requirement R3.2.1 is intended to address all voltage limitations applicable to generators, which could include nuclear plant operating voltage limits, generator terminal voltage limitations, and station service voltage limitations, for example.
21. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state.
22. The SDT has revised this requirement accordingly. The SDT does not feel that this standard distinguishes between PTP and network service. P6 has been revised and now shows as P2 in the revised table and shows a separation for performance above and below 300 kV. The SDT is still studying CFS and results will be shown in future revisions.

R3.3.2.2. Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits.

23. The SDT has modified the requirements for single and multiple Contingencies (See Requirement R 3.5).

R3.5. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~ if the following conditions are met:

24. The SDT feels the wording is equivalent and no change was made.
25. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.
26. The SDT has made this correction.
27. Tables 1 and 2 have been revised to replace the term “firm transfer” with “firm Transmission service”.
28. The SDT revised the Extreme Events accordingly.
29. Table 1 has been revised to include N-0.
30. The SDT made a change to the heading.
31. A footnote reference has been added for clarity.
32. Tables 1 and 2 have been revised to provide clarity. The term “Firm Transfer” has been replaced with “Firm Transmission Service”. In addition, the SDT has proposed a definition for Bus-tie Breaker in the second draft.

Bus-tie Breaker: A circuit breaker that is positioned to connect two individual straight bus substation configurations. (Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)

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Commenter	Yes	No	Comment
33. Tables 1 and 2 have been revised. P9.6 has been deleted and replaced with a reference in Requirement R11 in the second draft. **R11**. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information. 34. Tables 1 and 2 have been revised. The SDT cannot add "as applicable" to a standard because this term will make the standard unenforceable. The SDT notes that Requirements R3.4 and R4.5.2 allow for identifying and evaluating only those Extreme Events that are expected to produce more severe System impacts. 35. Breaker internal fault is a term used in the existing TPL standard. The SDT has added clarifying footnote number 5 in Table 1 and footnote number 4 to Table 2. 36. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 37. The SDT has made this change. 38. The SDT corrected the note. 39. This is explained in Table 1 - Note 5. 40. 300 kV applies to the equipment being studied and as defined for transformers and generators in Table 1 – Note 3. 41. The tables have been re-formatted for clarity. The SDT considers the term Non-Bus-tie Breaker as common nomenclature and has provided a definition of Bus-tie Breaker for clarity. The SDT feels that this requirement must remain to cover those situations where ring busses are not employed. CFS is still being studied by the SDT and will be handled in future revisions. 42. The SDT has changed the heading. 43. The SDT has made this change. 44. The SDT has made this change. 45. The SDT expects that increased documentation will improve coordinated Planning Assessments among the Planning Coordinator and the Transmission Planners.			
Tenaska	☑		The proposed standard contains a number of areas that need further definition, more explanation, or more specificity. 1. For example, requirement R1 should be rewritten as follows to make it clear who has responsibility for each requirement AND sub-requirement as the standard as written could be read to imply that Transimssion Owners and Generation Owners have to supply a load forecast to the Planning Coordinator: R1. Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide, as specified below, its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) : [Violation Risk Factor: TBD] [Time Horizon: TBD] R1.1. Each Load Serving Entity shall provide the Planning Coordinator load forecasts adhering, at a

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			minimum, to the following criteria: R1.1.1. Use of expected Load mix based on the actual or expected aggregate mix of industrial, commercial, and residential Loads. R1.1.2. Based on normal weather patterns as agreed to by the Planning Coordinator(s) and the Transmission Planner(s) for the area(s) of their responsibility. R1.1.3. Identification of Demand Side Management (DSM) Load reductions consistent with operational requirements. R1.2. Each Load Serving Entity shall provide the Planning Coordinator load models with supporting rationale that include power factor data based on historical System performance, validated by measurement during stressed System conditions, or documented Transmission planning area requirements. R1.3. Each Load-Serving Entity shall provide the Planning Coordinator the Firm transfers/Interchange Schedules and resources required to supply Load for each Balancing Authority. R1.4. Each Transmission Owner and Generation Owner shall provide the Planning Coordinator with known planned outages and long-term outages for Transmission and Generation equipment including protective relays with consideration given to spare equipment strategy. R1.5. Each Transmission Owner, Generation Owner, Resource Planner, and Transmission Planner shall provide known planned Facilities defined in accordance with the documented criteria of the Planning Coordinator, including but not limited to: Transmission Lines, generators, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies. The above is an example and I apologize for the poor pagination. However, the drafting team should look at each requirement/sub-requirement and specify precisely to which entity the requirement/sub-requirement applies. Other comments/concerns/questions with the proposed standard: 2. Does requirement R2 mean that you could have two assessments: one performed by the Transmission Planner and one performed by the Planning Coordinator? This could result in two assessments of the same facilities which may or may not be desired. 3. In Requirement 2.5.1, what is meant by increasing generation? Is there a minimum amount of increased generation or is it any increase? 4. In Requirements 2.5.2, 2.6.1, 2.6.2, and 2.6.3, what is meant by "material"? This needs more

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Commenter	**Yes**	**No**	**Comment**
			definition wherever the word "material" is used throughout the standard. 5. In Requirements 2.6.1, 2.6.2, and 2.6.3, the word System and system are both used. Whose System or system needs to be defined. Does that include neighboring system(s)? 6. In Requirement 2.7.3, "committed" and "proposed" need to be defined. 7. In Requirement 2.7.5, what needs to happen as a result of such review? Is something supposed to happen in the Corrective Action Plans depending on the implementation status of identified System Facilities and Operating Procedures? 8. In R3, what is "normal" performance (n-0)? Should this be a defined term? 9. In R3.2.1 and 3.2.2, why are these issues covered in a TPL standard as it seems to be more applicable to the Facility Ratings standards or the MOD10, 11, 12, and 13 standards? The TPL standard should probably reference these other standards for issues associated with ratings. 10. In R3.3.2, the reference to "single contingency" should reference the category (P1, P@, P#, etc.) in Table 1. 11. In R3.3.2.2, the term "firm transfers" needs to be defined. 12. In R3.3.3 and R3.4, reference is made to "expected to produce more servere System impacts." How does somebody determine what Extreme Events that are "expected to produce more servere System impacts?"

Response: 1. The standard has been revised to identify specific entities responsible for providing the required information.
2. The SDT expects that the Transmission Planner is coordinating assessments with the Planning Coordinator
3. The term is 'increasing generation capability', e.g., if your generator is rated at 100 MW today and 110 MW tomorrow, the 10 MW differential is the increased generation capability. The minimum is defined in Requirement R5.6.
4. Requirements R2.5 and R2.6 have been modified to address this concern. The SDT expects that the Transmission Planner and Planning Coordinator would exercise good engineering judgement when determining the need to perform a new study.

R2.5. The ~~plant~~Generating Unit Stability analysis portion of the Planning Assessment shall be analyzed consistent with Requirement ~~R4.6~~ R5.6 with studies for the year when the following changes that could affect stability margins occur:
R2.5.1. New generator(s) are added or generation modifications are made such as ~~increasing~~changes in generation capability or replacing the exciter ~~or addition of a power System stabilizer~~.
R2.5.2. Material Transmission System changes ~~in the electrical vicinity of existing generation are made~~ are made at or near the point of Interconnection of existing Generation such as the ~~addition or~~ removal of a Transmission Line ~~at or near the point of Interconnection~~ or the

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addition of a new substation in one of the Transmission Lines connected to the plant.

R2.6. Past studies may be used to support the Planning Assessment if they meet the following requirements:
R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

5. R2.6.1, 2.6.2, 2.6.3 – Requirements R2.6.1, R2.6.2, and R2.6.3 have been revised to clarify intent.

R2.6.1. For steady state, short circuit, or System Stability analysis: ~~if the study is less than three years old and no material changes have occurred to the System in the intervening period. Material changes include topology changes, generation additions/removals, and market structure changes~~ the study shall be five calendar years old or less.
R2.6.2. For steady state, short circuit ~~analysis~~, Generating Plant Stability, or System Stability analysis: ~~if the study is less than five years old and no material changes have occurred to the System in the intervening period.~~ the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area.
R2.6.3. ~~For plant and System Stability analysis: until material changes in the System make the study no longer valid. Material changes in the system include the addition of a Transmission Line or a generator.~~

6. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan.

7. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project.
8. Normal performance (n-0) describes the performance of the BES with no Contingencies. No other commenter expressed confusion. The

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Commenter	**Yes**	**No**	**Comment**
SDT does not believe a defined term is necessary. 9. Most commenters did not express concern regarding inclusion of these requirements in the proposed standard, so they were retained. The two requirements referenced relate to evaluation of Contingencies and are not addressed by the MOD or FAC standards. These requirements are intended to simulate the removal of Facilities that System protection is expected to disconnect for each Contingency without operator intervention in the steady state portion of the Planning Assessment. 10. R3.3.2.2 - Tables 1 and 2 have been modified to reflect your suggestion. 11. R3.3.2.2 – Requirement R3.3.2.2 has been revised and the term “firm transfers” has been deleted. **R3.3.2.2.** Following single Contingency events, ~~System adjustments other than shedding of firm Load or curtailment of firm transfers are permitted to meet performance requirements provided these adjustments can be accomplished within the time period allowed by the applicable time limited ratings.~~ Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. 12. R3.3.3 & R3.4 - The proposed standard allows the PC and TP to use engineering judgment and experience.			
TVA	☑		1. Requirement R1 does not belong in this standard. These requirements are covered by MOD standards. 2. Spare equipment strategy should be covered as a sensitivity study, but not included in the base case. 3. R2.1.1 should not be so prescriptive as to which years of 1-5 are studied. 4. The wording for R2.1.3 and R2.4.3 should be consistent. 5. Consideration should be given to the specific phases which are faulted in the simultaneous faults for P9 of the stability table. The results can be much different if the simultaneous faults occur on the same phase or different phases. 6. More guidance should be given for the term "Interruption of Firm Transfer Allowed" in Table 1. Firm transfer is not defined in the NERC glossary. The type of transmission service should be outlined here. 7. R2.7.1.1 - The project initiation date is not relevant in a reliability standard. 8. Extreme Event Descriptions 2. a. and b. should include mileage threshholds. 3. e. The term "large load" is vague and should be clarified. d. and f. are duplicates.

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Commenter	**Yes**	**No**	**Comment**
			c. and e. are duplicates. 9. Minimum generator voltage data required for R3.2.1 will be require extensive and costly generator testing and analysis to provide data necessary for transmission system studies. 10. R3.3.2.1 is an operational issue rather than a planning issue. 11. The addition of the "Corrective Action Plan" requires the TP to provide a significant amount of documentation for each deficiency identified by the studies. 12. Also, R3.2 requires that the studies simulate the protection scheme for all events. The current software tools cannot automate these studies for bus faults and breaker failure events, requiring each scenario to be studied manually. 13. The planning event designations are confusing because both the steady-state and stability tables have events P1-P9. A different designation should be used for one of the tables. 14. In R4.6 and other locations, the individual generator exemption of 20 MW should be increased to 75 MVA.

Response: 1. The SDT feels that some modeling requirements are not currently handled in the current MOD standards and has included them here until the MOD standards are revised.
2. The SDT assumed that all entities have a spare policy today. The studies are to be performed on that basis. Duration of Contingencies considered in the studies will be based on this policy as will be the applicable equipment ratings. If the entity feels that the policy may or can change, the entity may elect to add this change as a sensitivity study.
3. The SDT is providing guidance regarding the studies that could be incorporated in an assessment while not being totally prescriptive. The standard does not require that all 5 years be studied. The standard requires the assessment addresses the five year period. Section 2 provides guidance as to the minimum number of current studies required to produce a meaningful assessment without being totally prescriptive. It is the responsibility of the entity to determine if past studies, in conjunction current studies, sufficiently demonstrate that the performance requirements are met. If past studies in conjunction with the required current studies are not sufficient to demonstrate that the System can meet the performance needed, the entity will need to run additional current studies that demonstrate it can meet the requirements.
4. The SDT is providing some guidance on what needs to be included in sensitivity studies while not being totally prescriptive. The wording in Requirement R2.1.3 describes sensitivities for the steady state horizon while Requirement R2.4.3 describes the sensitivities for dynamic analysis. The wording in these requirements is different but parrallel. To increase the consistency Requirement R2.4.3 has been modified to require documentation of why the listed sensitivities were or were not selected for specific studies.

R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, ~~S~~sensitivity case(s) that stress the System to reflect one or more of the following conditions shall be run ~~with documentation provided explaining the rationale for the selected~~

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Commenter	**Yes**	**No**	**Comment**
~~sensitivity(ies)~~ and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied: 5. The SDT agrees that the results can be different. However, the SDT feels that in most instances, the person performing the study will select a three phase fault which is the most severe case and easiest to simulate. 6. The SDT has revised Tables 1 and 2 to replace the term "Firm Transfer" with "Firm Transmission Service". 7. The SDT agrees that this information is not required to meet reliability standards. It was specifically added as an additional piece of information in the Planning Assessment to allow some level of peer review and provide some level of confidence that the proposed plan could in fact be completed to meet the reliability objective. Initiation dates are only required in the near term since longer term plans tend to move in time and only have general scheduling associated with them. 8. The SDT believes that there should not be a threshold as you are trying to understand the robustness of the System. Large is left to the discretion and good professional judgment of the evaluator. Note 3 has been re-written for clarity and to delete duplications. 9. The requirement is intended to provide for the simulation of generator tripping in response to low system voltages that would cause auxiliary system motors to trip in the steady state portion of the Planning Assessment. 10. The requirement concerning Consequential Load is to address FERC Order 693, which directs that the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 11. The SDT does not percieve this as an onerous report requirement. The intent is that a list of proposed upgrades be reviewed and modified on a periodic basis. The intent of making the information available is to notify parties that may be impacted by a particular project of a change in the implementation of the project. 12. The SDT agrees that most automated Contingency analysis tools do not do this unless you actually modeled the bus in detail. However, we expect that "engineering judgment", based on intimate knowledge of the System, will be exercised by the planner to distinguish between what studies are important and those that aren't. The requirement is not intended to cover all possible scenarios. 13. The SDT discussed this suggestion and decided to retain the current designations. 14. This is consistent with FERC Order 693, the Large generator Interconnection procedures, and the registry criteria.			
TSGT	☑		1. R1 and R2 address some Load Forecast issues, but are not exhaustive specifications of what Load Forecast range to use in studies. There needs to be some mention of exceedance probability (ExPr) in Load Forecast criteria. For example, we use a forecast with a low ExPr in our studies because we are concerned that, if the system was planned for 50% ExPr (a lower forecast), actual deviation from that forecast might result in load at certain locations exceeding operating margins built into the interconnected transmission system designed to serve only the 50% ExPr forecast load. 2. Load Specifications in R2.4 are ambiguous for the reasons stated above. 3. Maximum study ages in R2.6.1 and R2.6.2 seem arbitrary. The time limit does not seem to add anything to the criteria if no material changes have occurred. If spot checks of the most critical areas indicated no criteria violations, there should be no reason to rerun studies. To correct this problem, we suggest using the term "assessment" rather than "study". For most people, "study" implies detailed modeling and simulation analyses summarized in a report, whereas "assessment" implies a

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Commenter	**Yes**	**No**	**Comment**
			reasonable, systematic evaluation of a system which does not necessarily include detailed analysis for the entire system.
Response: 1 & 2. Requirement R1 has been modified to make TPL-001-1 comport with existing modeling standards and to require documentation when modification of data provided in these standards is necessary for the planning studies addressed in TPL-001-1. Requirement R2.1.3.1 addresses your concern about Load forecast issues and allows for sensitivity studies of the variability of forecasts based on a number of factors. **R1**. ~~Each Resource Planner, Transmission Planner, Transmission Owner, Generator Owner, and Load-Serving Entity shall each provide its respective Planning Coordinator with the following modeling information required for System performance studies upon request (within 30 calendar days) :~~ Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources. 3. The SDT set the age limit on studies to 5 years based on the fact that relatively "small" changes can accumulate with time to the extent that study results might be affected. Requirement R2.6.2 sets reasonable criteria on what System changes might materially affect existing study results, and the SDT does not consider the criteria to be arbitrary. The term "study" was deemed more appropriate as used here than "assessment".			
AESO	☑		The Alberta Electric System Operator (AESO) supports the comments from WECC with the exception of Question #19 where the AESO agrees with the proposed requirement R2.7.4 by the SDT.
Response: The SDT has modified the standard to require only the Corrective Action Plan and indicates what is meant by the word plans. The SDT feels that the assessment and making it available to others will by its very nature provide all the information necessary to understand which plans changed and the basis for the new plans.			
WECC TEP	☑		1. R1.3 requires the provision of firm transfer/Interchange Schedules and resources required to supply load for each Balancing Authority. It may not be possible to have reasonably accurate information on firm transfers and Interchange Schedules for years into the future. Within WECC, we develop base cases that represent reasonably stressed conditions that model power flows stressing various paths. Therefore, within WECC, we design the system to operate at levels that can support all sorts of commerce, including the effects of loop flow, and firm and non-firm contracts, in addition to other possibilities. It would be difficult to develop information from this mixture that includes only firm transactions for such future base cases. In addition, WECC does not allow operations at levels not previously studied. Therefore, an exercise to determine firm transaction/schedules would produce information that will be of little value to support reliability in WECC. 2. R2.7.1.2 requires identification of system deficiencies and accociated corrective action for the Long Term Transmission Planning Horizon. This requirement needs to tie to the lead times to implement the corrective action(s). For example, if a 500 kV transmission line is needed to correct a deficiency that surfaces in the tenth year, then this requirement is reasonable. However, if the deficiency is on a low voltage system, that can be resolved with short lead-time projects (such as

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Commenter	**Yes**	**No**	**Comment**
			installing a small capacitor bank) then this requirement would seem to be too prescriptive. 3. R1.5 requires providing modeling information as part of R1 on a number of transmission planned facilities, including circuit breakers. Since circuit breakers are part of a transmission line, we are not sure how a circuit breaker would be modeled separately, as required. 4. R3.2.1 requires that "studies shall consider the minimum steady state voltage limitations of all generators". Since generators (as well as other facilities) have both high and low voltage limits, the standard should require consideration of both high and low voltage limits. 5. In R.3.2.2, please provide a reference for relay loadability. 6. R.3.3.2.1. requires that Consequential Load loss (expected maximum demand and expected duration) following a single contingency shall be identified in the Planning Assessment. We suggest deleting this requirement. By definition, consequential load loss following a contingency can not be avoided and should not be considered an impact on the operation of the BES. It should be part of local service reliability between an entity and its local regulatory agency or contractual relationship between individual parties and not in a NERC Standard governing the operation of a BES. 7. Proposed revision to R3.5 – "Manual and automatic generation runback and generator tripping are allowed as a response to single and multiple contingencies as long as Facility Ratings are not exceeded and the result of the generator action, such as loss of reactive resource, impact on reserves, and restart time of tripped unit(s), meets the performance requirements in the tables." Example for the need for flexibility in the selection of generation runback and/or tripping to meet the requirements of R3.5 – The time period for a particular Emergency Rating might require faster generation redispatch than a runback or set of runbacks are capable of providing. Therefore, it may be necessary to trip one 100 MW unit rather than runback several units for a total of 100 MW. Planning and Operations need flexibility to coordinate with the requirements of Engineering who established the Facility Ratings. No need for R3.6 with above revision to R3.5. 8. Performance standard "P5" (Q.21- 23) does not allow for the use of load shedding (safety nets) required by some utilities to protect against cascading outages if a transmission line is already out of service and a forced outage of another major element occurs. "System adjustments" might not be possible in a load pocket or local load-serving area to prevent "non-consequential load loss" after loss of a second transmission line to the load-serving area. The use of load shedding for such rare

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Commenter	**Yes**	**No**	**Comment**
			events is an established practice and least cost alternative that does not unreasonably compromise reliability of the WECC system. It is also an acceptable and necessary tradeoff from over burdening customers with additional expensive transmission lines and permitting risk in the West where remote generation resources have historically required power to be carried over long distances. The tradeoffs between economics (building hundreds of miles of new transmission lines or build out hundreds of MW of new load-side generation versus load shedding schemes) and the impact of these rare events should be under the purview of local and state jurisdictions, as long as impacts do not result in cascading events outside of the affected jurisdiction. As long as interconnected reliability or neighboring system operation is not negatively impacted, customer interruption size and frequency should be left to the Transmission Providers discretion and to the jurisdiction of state regulators. The amount of load to be shed and its frequency is primarily an issue for state jurisdiction because it is a matter of the cost/benefit associated with customer service regardless of the voltage level problem. In general, incidences of non-consequential loss of customer load events related to contingencies on the back-bone transmission system are rare when compared to other causes of customer outages. Assuming interruptions to customer service are significant, the state regulators and other related constituents will ultimately be responsible for approving any transmission line facilities or generation additions needed to assure reliability. Implementing an immediate change to this current established practice is not rational or technically feasible due to the long and arduous regulatory and permitting processes that are required to construct new transmission facilities or new load-side generation. Implementation of the standard as written would take many years. At a minimum, even if it is determined that Congress's intent was to create stricter standards, a phase-in period must be included to allow utilities time to obtain necessary permits, regulatory approval and cost recovery to meet the stricter standards.

Response: 1. The SDT understands your concern. The SDT only anticipates that known firm transfers and schedules be included in the base cases. Non-firm transfers may be included in the sensitivity studies as detailed in Requirement R2.1.3. Requirement R1.3 in the first draft of TPL-001-1 is now shown as Requirement R10 in the revised draft.

R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information.

2. Based on several comments and consideration by the SDT, the SDT has modified Requirement R2.7.1 and deleted Requirements R2.7.2 through R2.7.4. The standard now refers to "actions" needed to achieve required System performance without trying to distinguish between committed and proposed projects. It also lists examples of what is intended by the word "actions".

R2.7.1. ~~Identify~~ List System deficiencies and the associated actions needed to achieve required System performance. ~~including Transmission~~

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Commenter	Yes	No	Comment
~~and generation improvements, DSM, new technologies, or Operating Procedures including the duration of interim Operating Procedures.~~ Such actions may include installation, modification, retirement, or removal of Transmission and generation Facilities and any associated equipment such as protective or Special Protection Schemes, rate applications, DSM, or other initiatives, new technologies, or Operating Procedures including how long the Operating Procedures will be needed as part of the Corrective Action Plan. 3. The SDT agrees that circuit breakers are generally not modeled separately in planning simulations. However, the addition or removal of a circuit breaker could modify network topology as modeled for planning simulations, which this requirement attempts to capture. 4. Voltage limits are included in the tables to cover both high and low voltage limits. However, the minimum limits in Requirement R3.2.1 are, generally, the more critical concern for system performance scenarios and this requirement was included by team consensus. 5. NERC document "Relay Loadability Exceptions, Determination and Application of Practical Relaying Loadability Ratings ", is contained on this ftp site: ftp://ftp.nerc.com/pub/sys/all_updl/pc/spctf/ExceptionsV1.pdf. Other information may also be obtained from: http://www.nerc.com/~filez/spctf.html 6. R3.3.2.1 - The requirement concerning Consequential Load is to address FERC Order 693, which directs the ERO, among other things, to clarify footnote (b) in regard to Load loss following a single Contingency, specifying the amount and duration of Consequential Load Loss and System adjustments that are permitted after the first Contingency to return the System to a normal operating state. 7. The SDT has modified the requirements to allow for single and multiple Contingencies tripping (See Requirement R 3.5). **R3.5**. Manual and automatic generation run-back/tripping is allowed as a response to a single ~~and~~ or multiple Contingenc~~ies~~y ~~as long as Facility Ratings are not exceeded.~~if the following conditions are met: 8. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power served by them can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure not only are other System Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of larges generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more expensive ring-bus, breaker-and –a-half or double bus-double breaker protection schemes as opposed to the more simplistic and lesser cost single bus arrangements that are			

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Commenter	**Yes**	**No**	**Comment**
commonly found on lower voltage Systems. The feedback received from industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenter's questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenter's even questioned why the more stringent approach was not applied to the entire 100kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The SDT plans to draft an implementation plan. This implementation plan will address, among other issues, the other standards, which will need to be brought into alignment with this standard. The plan will be provided for the third posting of the standard.			
WPS	☑		Within R1.1.2, the Planning Coordinator and the Transmission Planner is required to define what constitutes "normal weather patterns" for the purpose of establishing load forecasts. However, the PC and/or TP are not the appropriate entities to establish "normal weather patterns"; the LSEs, who actually develop load forecasts and have the expertise, are the appropriate entities to establish normal weather patterns. Additionally, this requirement should consider requiring the 50/50 probability load forecast from the LSEs.
Response: This requirement has been eliminated in response to various industry comments.			
Duke Energy		☑	
Northwestern Energy		☑	
New York ISO		☑	
Response: Thank you.			