Consideration of Comments on Third Draft of Standard TPL-001-1 — Project 2006-02

The Assess Transmission Future Needs Standard Drafting Team thanks all commenters who submitted comments on the third draft of the TPL-001-1 standard. This standard was posted for a 45-day public comment period from May 26, 2009 through July 9, 2009. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 85 sets of comments, including comments from more than 170 different people from over 85 companies representing 9 of the 10 Industry Segments as shown in the table on the following pages.

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

Due to industry comments and continuing review of Order 693 directives applicable to TPL, changes have been made to the following:

Definitions: Consequential Load Loss, Non-Consequential Load Loss, and Year One

Requirements: R1 and parts 1.1, 1.1.1, 1.1.2, 1.1.3, 1.1.4, 1.1.5, and 1.1.6; R2 and parts 2.1, 2.1.3, 2.1.4 (and bullets 1, 3, and 7), 2.1.5, 2.1.6, 2.2, 2.2.1, 2.3, 2.4, 2.4.1, 2.4.3 (and bullets 1 and 3), 2.5, 2.6.1, 2.6.2, 2.7, 2.7.1 bullet 2, 2.7.2, 2.7.5, 2.7.6, 2.8, 2.8.2, 2.9; R3 and parts 3.1, 3.2, 3.3, 3.3.2, 3.3.3, 3.3.4, 3.4, 3.4.1, 3.5, 3.6; R4 and parts 4.1, 4.1.1, 4.1.2, 4.1.3, 4.2, 4.3, 4.3.2, 4.3.3, 4.3.4, 4.4, 4.4.1, 4.5; R5, R6, R7; R8 and part 8.1.

Measures: M1, M5, M7, and M8.

VSLs: R1, R2, R3, R4, R5, R6, R7, and R8.

Table elements: Header notes ‘a’, ‘c’, ‘f’, and ‘k’; P4, P7; extreme event ‘a’, steady state 1, Stability 1; footnotes: 2, 3, 4, 7, 9, 10, and 11

Implementation Plan

In addition, the SDT has reformatted the standard to meet the latest guidelines.

The SDT feels that the volume and scope of these changes warrants a fourth posting of this standard.

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and 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.

Index to Questions, Comments, and Responses

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.	Group	William Bigdely	Dominion - Electric Transmission	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	J. Ronnie Bailey	Dominion - Electric Transmission Planning	SERC	
2.	Kirit Doshi	Dominion - Electric Transmission Planning	SERC	
3.	Craig Crider	Dominion - Electric Transmission Planning	SERC	
4.	Mehdi Shakibafar	Dominion - Electric Transmission Planning	SERC	
5.	Dennis Kaminsky	Dominion - Electric Transmission Planning	SERC	
6.	Solomon Yirga	Dominion - Electric Transmission Planning	SERC	
7.	Michael Gildea	Dominion - Electric Market Policy	SERC	
8.	Louis Slade, Jr.	Dominion - Electric Market Policy	SERC	
9.	Jalal Babik	Dominion - Electric Market Policy	SERC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
2.	Group	Guy Zito	Northeast Power Coordinating Council										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Ralph Rufrano	New York Power Authority	NPCC	5
2.	Alan Adamson	New York State Reliability Council	NPCC	10
3.	Gregory Campoli	New York Independent System Operator	NPCC	2
4.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

5.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
6.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
7.	Manuel Couto	National Grid	NPCC	1
8.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1
15.	Michael Schiavone	National Grid	NPCC	1
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Chris Orzel	FPL Energy/NextEra Energy	NPCC	5
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
20.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
3.	Group	W. R. Schoneck	Transmission Planning	X		X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Shaffer	FPL	FRCC	
2.	Pedro Modia	FPL	FRCC	
3.	Carlos Candelaria	FPL	FRCC	
4.	Kiko Barredo	FPL	FRCC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
4.	Group	Phillip R. Kleckley	SERC Engineering Committee Planning Standards Subcommittee			X							

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren	SERC	1
2.	Jim Kelley	PowerSouth Energy Coop	SERC	1
3.	Pat Huntley	SERC Reliability Corp	SERC	10
4.	Bob Jones	Southern Co. Services	SERC	1
5.	David Marler	TVA	SERC	1

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
5.	Group	Steve Hill	Modesto Irrigation District	X		X		X					

	Additional Member	Additional Organization	Region	Segment Selection
1.	Spencer Tacke	Modesto Irrigation	WECC	

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Matt Muldoon	OPUC									X	

	Additional Member	Additional Organization	Region	Segment Selection
1.	Jerry Murray	OPUC	WECC	9

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Richard Kafka	Pepco Holdings, Inc. - Affiliates	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bill Mitchell	Delmarva Power & Light	RFC	1
2.	John Radman	Potomac Electric Power Co.	RFC	1
3.	Jim Summers	Atlantic City Electric	RFC	1
4.	Brian Willis	Potomac Electric Power Co.	RFC	1
5.	Lisa Fairchild	Potomac Electric Power Co.	RFC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Denise Koehn	Bonneville Power Administration	X				X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	Transmission Planning	WECC	1
2.	Chuck Matthews	Transmission Planning	WECC	1
3.	Kyle Kohne	Transmission Planning	WECC	1
4.	Melivin Rodrigues	Transmission Planning	WECC	1
5.	Kendall Rydell	Transmission Planning	WECC	1
6.	Larry Furumasu	Transmission Planning	WECC	1

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Carol Gerou	MRO MRO NERC Standards Review Subcommittee										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Neal Balu	Wisconsin Public Service	MRO	3, 4, 5, 6
2.	Terry Bilke	Midwest ISO Inc.	MRO	2
3.	Ken Goldsmith	Alliant Energy	MRO	4

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10

4.	Jim Haigh	Western Area Power Administration	MRO	1, 6
5.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6
6.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
7.	Scott Nickels	Rochester Public Utilities	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
10.	Group	Rick Foster	SERC Engineering Committee Dynamics Review Subcommittee (DRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Sullivan	Ameren Services Company	SERC	1
2.	Anthony Williams	Duke Energy Carolinas	SERC	1
3.	Sujit Mandal	Entergy	SERC	1
4.	Venkat Kolluri	Entergy	SERC	1
5.	John O'Connor	Progress Energy Carolinas	SERC	1
6.	Bob Jones	Southern Company Services, Inc. - Trans	SERC	1
7.	Lee Taylor	Southern Company Services, Inc. - Trans	SERC	1
8.	Robbie Bottoms	Tennessee Valley Authority	SERC	1
9.	Tom Cain	Tennessee Valley Authority	SERC	1
10.	Herb Schrayshuen	SERC Reliability Corporation	SERC	10

		Commenter	Organization	1	2	3	4	5	6	7	8	9	10
11.	Group	Ian Grant	SERC Engineering Committee Reliability Review Subcommittee (RRS)	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Curtis Stepanek	Ameren Services Company	SERC	1
2.	Eugene Warnecke	Ameren Services Company	SERC	1
3.	Kevin Hopper	Associated Electric Cooperative, Inc.	SERC	1
4.	Karl Kohlrus	City of Springfield, IL - CWLP	SERC	1
5.	Brian D. Moss	Duke Energy Carolinas	SERC	1
6.	Julia Tucker	East Kentucky Power Cooperative	SERC	1
7.	Kham Vongkhamchanh	Entergy	SERC	1

		Commenter	Organization	Industry Segment 1	2	3	4	5	6	7	8	9	10

8.	Ken Wofford	Georgia Transmission Corporation	SERC	1
9.	Mark Kuras	PJM Interconnection, LLC	SERC	1
10.	Mark Byrd	Progress Energy Carolinas	SERC	1
11.	Clay Young	South Carolina Electric & Gas Company	SERC	1
12.	Rod Hardiman	Southern Company Services, Inc. - Trans	SERC	1
13.	Timothy Smith	Tennessee Valley Authority	SERC	1
14.	Herb Schrayshuen	SERC Reliability Corporation	SERC	10

				1	2	3	4	5	6	7	8	9	10
12.	Group	Doug Hohlbaugh	FirstEnergy Corp	X		X	X	X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	John Stephens	FE	RFC	1
2.	Jeff Mackauer	FE	RFC	1

				1	2	3	4	5	6	7	8	9	10
13.	Group	Ben Li	IRC Standards Review Committee		X								

	Additional Member	Additional Organization	Region	Segment Selection
1.	Matt Goldberg	ISO-NE	NPCC	2
2.	Bill Phillips	MISO	MRO	2
3.	Anita Lee	AESO	WECC	2
4.	James Castle	NYISO	NPCC	2
5.	Charles Yeung	SPP	SPP	2
6.	Steve Myers	ERCOT	ERCOT	2
7.	Lourdes Estrada-Salinero	CAISO	WECC	2
8.	Pat Brown	PJM	RFC	2

				1	2	3	4	5	6	7	8	9	10
14.	Individual	Tim Ponseti, VP	TVA System Planning	X									
15.	Individual	Eric Mortenson	Exelon Transmission Planning	X		X		X					
16.	Individual	Hugh Francis	Southern Company	X		X		X					
17.	Individual	David Bradt	United Illuminating	X									
18.	Individual	Cordell Grand	Louisiana Energy and Power Authority			X							

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
19.	Individual	Mark Graham	System Protection and Transmission Planning Department	X									
20.	Individual	John Cummings	PPL Energy Plus						X				
21.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
22.	Individual	Brandy A. Dunn	Western Area Power Administration	X									
23.	Individual	Min Tra	Tampa Electric	X				X					
24.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X			X	X					X
25.	Group	Frank Gaffney, Regulatory Compliance Officer	FMPA, and it's All-Requirements Project Participants, as follows: Lakeland Electric; Fort Pierce Utilities Authority; Keys Energy Services; City of Vero Beach; Beaches Energy Services; Kissimmee Utility Authority; and Lake Worth Utilities	X		X			X				
26.	Individual	Mark Byrd	Progress Energy Carolina (PEC)	X									
27.	Individual	John Allen	City Utilities of Springfield, MO	X									
28.	Individual	Blake Williams	CPS Energy	X				X					
29.	Individual	Tom Mielnik	MidAmerican Energy Company	X		X		X	X				
30.	Individual	James Tucker	Deseret Generation & Transmission	X		X		X					
31.	Individual	Michael R. Lombardi	Northeast Utilities	X		X	X	X					
32.	Individual	Brian Keel	SRP	X									
33.	Individual	L. Earl Fair	Gainesville Regional Utilities	X									

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
34.	Individual	Don Gilbert	JEA	X		X		X					
35.	Individual	Catherine Mathews	NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	X		X		X					
36.	Individual	Dilip Mahendra	SMUD	X		X	X	X	X				
37.	Individual	Bart White	Progress Energy Florida, Inc.	X		X							
38.	Individual	Alice Murdock	Xcel Energy	X		X			X				
39.	Individual	Kathleen Goodman	ISO New England, Inc.		X								
40.	Individual	Baj Agrawal	Arizona Public Service Co	X		X							
41.	Individual	Randy MacDonald	New Brunswick System Operator		X								
42.	Individual	Dana Cabbell	Southern California Edison Company	X		X							
43.	Individual	Terry Huval	Lafayette Utilities System										
44.	Individual	Robert Easton	Western Area Power Administration	X								X	
45.	Individual	Robert Priest	Mississippi Delta Energy Agency										
46.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
47.	Individual	Phil Sanchez	Western Area Power Administration	X								X	
48.	Individual	Chifong Thomas	Pacific Gas and Electric Co,	X		X		X					
49.	Individual	Kirit Shah	Ameren	X		X		X	X				
50.	Individual	Joe Seabrook	Puget Sound Energy, Inc.	X									
51.	Individual	Eric Bryant	Maine Public Advocate								X	X	

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
52.	Individual	Scott Helyer	Tenaska, Inc.					X					
53.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
54.	Individual	Brent Ingebrigtson	E.ON U.S.	X		X		X	X				
55.	Individual	Sergio Garza	LCRA Transmission Services Corporation	X									
56.	Individual	Carol Sedewitz	National Grid	X									
57.	Individual	Edward J Davis	Entergy Services, Inc	X		X		X	X				
58.	Individual	Joe Knight	Great River Energy	X		X		X	X				
59.	Individual	Pat Harrington	BC Hydro			X		X	X				
60.	Individual	Marie Knox	Midwest ISO		X								
61.	Individual	Jessica Rice	NV Energy	X									
62.	Individual	Mark Kuras	PJM		X								
63.	Individual	David Albers	Brazos Electric Cooperative	X									
64.	Individual	James H. Sorrels, Jr.	American Electric Power	X		X		X	X				
65.	Individual	Michael Ayotte	ITC Holdings	X									
66.	Individual	Mary Ann Groszek	Northern Indiana Public Service Company	X									
67.	Individual	Wang, Yu (David)	San Diego Gas and Electric Co	X									
68.	Individual	Peter S. Schommer	Minnesota Power			X		X	X				
69.	Individual	Tim Wu	LADWP	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
70.	Individual	John Collins	Platte River Power Authority	X									
71.	Individual	Larry Brusseau	MAPPCOR			X							
72.	Individual	Aaron Staley	Orlando Utilities Commission	X				X					
73.	Individual	Jason Shaver	American Transmission Company	X									
74.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
75.	Individual	David Angell	Idaho Power	X									
76.	Individual	Casey Hashimoto	Turlock Irrigation District			X							
77.	Individual	Gregory Campoli	New York Independent System Operator		X								
78.	Individual	Greg Rowland	Duke Energy	X		X			X				
79.	Individual	David M. Conroy	Central Maine Power Company	X									
80.	Individual	Darcy O'Connell	California ISO		X								
81.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
82.	Individual	Dan Rochester	Independent Electricity System Operator		X								
83.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				
84.	Individual	Rao Somayajula	ReliabilityFirst Corporation										
85.	Individual	Vivian Wang	British Columbia Transmission Corporation										

1. Requirement R1 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made several clarifying changes to Requirement R1 and its various parts based on industry comments. The major changes made were to delete the phrase "including requirements of regulatory authorities and other legal obligations" from Requirement R1, the addition of "existing facilities' to the parts of Requirement R1, changing 'planned' outages to 'known' outages, combining the part calling for Firm Transmission Service and Interchange, and clarifying the final part as to the use of resources. Measure M1 was revised to provide greater clarity. The VSLs for Requirement R1 have been revised to match the new wording in the requirement.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

1.1 System models shall represent:

1.1.1 Existing Facilities

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

1.1.3 New planned Facilities and changes to existing Facilities

1.1.4 Real and reactive Load forecasts

1.1.5 Known commitments for Firm Transmission Service and Interchange

1.1.6 Resources required to supply Load

M1 Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement

		MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		R1.

Organization	Question 1 Comment
Dominion - Electric Transmission	R1 - Dominion questions the legal authority NERC has to include the recently inserted language "including requirements of regulatory authorities and other legal obligations." This language is too broad and far exceeds the jurisdiction of NERC's mission. R1.1.5 - Dominion has seen base case models built by other transmission entities which do not include area interchanges for all areas and must be solved with area interchange "turned off". Would these base case models be in violation of R.1.1.5?
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that the base cases should include any area interchange that is planned between utilities. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Northeast Power Coordinating Council	R1--There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within the purview of this standard. Guidance is needed on how to treat base case generation dispatch and system transfers. The inclusion of "requirements of regulatory authorities and other legal obligations" is not understood. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. "Simulate" should be changed to "incorporate". R1.1.1 Priority comment. Only known long-term outages of generation and transmission should be required to be modeled.

Organization	Question 1 Comment
	R1.1.2 comment - Do we need to have the list of equipment to model? How are circuit breakers, and other equipment modeled? Also, what should be the level of detail and the form that Protection System Equipment and Control Devices be modeled? We recommend deleting the list. Make R1.1.2 simply read as follows: R1.1.2--Projected system configuration, taking into account new planned Facilities and changes to existing Facilities, for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange "R1.1.6 comment " This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-Contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has changed the word "simulate" to "represent" in Requirement R1.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices is typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Existing Facilities are now shown under Requirement R1, part 1.1.1.

1.1.1 Existing Facilities

Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. The intent of the SDT was that this includes network resource as per the FERC LGIP but that it is not limited to that. The SDT has clarified the wording for Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Transmission Planning	R1.1. COMMENT: Should read: Models for performing the studies needed to complete the Planning Assessment shall represent: instead of Models for the Planning Assessment shall represent: R1.1.1. COMMENT: Should the requirement specify which known outages should be modeled? For example, would it be considered incomplete and therefore a violation if a known generator maintenance outage with a one week duration is not included (not modeled off-line) in a case that represents a full summer season at peak conditions? Please provide guidelines as to what duration outages should be modeled in representative planning horizon cases. (i.e. one day, several days, one week, one month, in a case that represents a significantly longer time period.) R1.1.2. COMMENT: Should add Transformers to this list; COMMENT: What is meant by “represent” - Planning models do not typically include explicit Circuit breaker modeling. The planning models used for power flow, dynamics and short circuit analysis represent the power system with busses and branches. The effect of circuit breakers is taken into account as part of contingency modeling. Including circuit breakers as a sub-requirement is likely to result in transmission planners being required to demonstrate that circuit breakers are modeled. Explicit representation of circuit breakers with existing software would result in major convergence problems due to large number of low impedance branches. COMMENT: Should clarify "Protection System equipment" to apply only to system stability models. Does this mean all relays on the system must be included in the dynamics modeling? While a certain limited number of protective relays can be modeled with the software used for dynamics, it is not practical to model more than a very small percentage of the protection systems used in the BES. Including protective relays as a sub-requirement is likely to result in transmission planners being required to demonstrate that all protective relays are modeled which is an impossible task. The modeling of protective relays should be caveated with as deemed appropriate. COMMENT: "Control devices" Should be specific. Is this for Phase Angle Regulators (PAR), Synchronous Condensers, Static Var Compensators (SVC), exciters, governors etc? Control devices should be specifically defined as the following: PAR, SVC, HVDC. COMMENT: "New technologies" seems too broad. Needs to be better defined. Planning models may not have the capability to adequately model new technologies. R1.1.4. Firm Transmission Service COMMENT: Should add that is expected to be utilized in the study case scenario because not all Firm Transmission Service can be included in every study case model. Some firm transmission reservations (Network Resources that could be Reserves) are used optionally depending upon the availability of other Network resources. The following apply to all VRF, Time Horizon, Measure, Data Retention, and VSL for all requirements in the standard.VRF: Agree. No comment.

Organization	Question 1 Comment
	Time Horizon: COMMENT: Long-Term Planning This is confusing. Is it only the newly defined Long-Term Transmission Planning Horizon? Shouldn't it include the Near-Term Transmission Planning Horizon Suggest Long-Term and Near-Term Transmission Planning Horizon as used in definitions. Measure: Agree. No comment. Data Retention: Agree. No comment. VSL: Are bullets in requirements all required? (I.e. If circuit breakers are not explicitly modeled, as the bullet list in R1.1.2 seems to indicate, is it a violation?) What is meant by did not simulate projected System conditions as described in R1. How are projected System conditions criteria described in R1?

Response: The SDT has reworded the requirement.

1.1 System models shall represent:

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7**.**

The SDT has revised Requirement R1, part 1.1.2 to provide clarity.

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.). New technologies were removed from the equipment list under Requirement R1, part 1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7

Models are only specific to the case study. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon - The time horizons available for mitigating a violation to a requirement include the following::

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment
	• **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Thank you for your response on Measures and Data Retention.

The SDT has removed the equipment list. Transmission lines, generators, and reactive power devices were removed from the equipment list due to already being included in MOD standards. Circuit breakers, Protection System equipment, and control devices were removed from the equipment list since these items are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note c in Table 1. New technologies were removed from the list as they are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has deleted the equipment list.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

Requirement R1 contains the requirements needed for creating proper base cases.

SERC Engineering Committee Planning Standards	R1.1.2: In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the power flow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses

Organization	Question 1 Comment
Subcommittee	included in the power flow models would increase with additional breaker modeling. Protection System Equipment: The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Modesto Irrigation District	Comment: Are all bullets under R1.1.2 required to be explicitly modeled or are the effect of the devices or the effect of the removal of the devices to be modeled? We don’t explicitly model circuit breakers or explicitly model protection system equipment in the steady state model. R1.1.4 should refer to expected transfers to be consistent with the bullet under R2.1.3. Please explain the difference between R1.1.4 and R1.1.5
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Interchange is defined in the NERC glossary as “energy transfers that cross Balancing Authority boundaries” while Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.”	
OPUC	1. Requirement R1 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Language in R1.1.2 still needs further clarification. Base case models do not clarify modeling required for the effect or absence of circuit breakers, protection system equipment and control devices. B: Clarity would be increased were R1.1.4 to refer to expected transfers rather than Firm Transmission Service, permitting the elimination of then redundant R1.1.5 C: Removing “including requirements of regulatory authorities and other legal obligations” at the end of R1 would also eliminate redundant text.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices	

Organization	Question 1 Comment
are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed “including requirements of regulatory authorities and other legal obligations” since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co California ISO	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as “energy transfers that cross Balancing Authority boundaries” while Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include	

Organization	Question 1 Comment
known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? An order of precedence is needed as part of this requirement. Suggest adding terminal equipment to the list of planned facilities. The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective areas for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the

Organization	Question 1 Comment
	powerflow models would increase with additional breaker modeling. In R1.1.2, don't we need to also represent the existing transmission system, and not just changes to the existing system In R1.1.2, does the phrase for each year signify each year for which assessment work was performed, or each year of the Near-Term and Long-Term Transmission Planning Horizon? The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. In bullet five of R1.1.2, what protection system equipment is to be included in the stability models In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models Concerned about only having one year to implement all new modeling requirements - especially the additional relay requirements noted in R1.1.2. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, which one should rule? There may be a need to add definitions to discern the difference between planned and proposed projects. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Does there need to be a reference in R1 to NERC Reliability Assessment Guidebook version 1.2 on pp 17-18 for everyone to use a 50/50 load forecast for inclusion in the planning models?? R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)? Not sure if this is applicable to Requirement 1 or 2.

Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

The SDT has revised Requirement R1, part 1.1.1 to include "existing system".

1.1.1 Existing Facilities

The reference to “year” has been removed from Requirement R1, part 1.1.2 (now part 1.1.3)

Organization	Question 1 Comment
1.1.3 New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. 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.). New technologies were removed from the equipment list in Requirement R1, part 1.1.2 (now part 1.1.3) since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. In Draft 1, the SDT proposed using the terms "planned" and "committed" (similar to your proposal of proposed and planned) to distinguish the "firmness" of projects. Based on industry comments, the SDT eliminated the terms from Draft 2. No change made. Requirement R1, part 1.1.2 (now part1.1.3) has been revised as described above. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
FirstEnergy Corp	As stated in prior comment periods, we hold the opinion that the TPL-001-1 standard should start from the premise that a valid system model exist based on MOD-010, MOD-012 and other FERC approved MOD standards that are not referenced by this TPL-001-1 standard. The inclusion of R1 introduces an overlap and potential for double jeopardy violations that need not occur. The TPL-001-1 standard should not delve into model building and keep to its core purpose of assessing future performance of the BES.Specific comments, Requirements of R1A. R1.1.2: The last bullet "New Technologies" is too vague and should be struck from the requirement. B. R1.1.4: It is not well understood how "Firm Transmission Service" would be evaluated by a compliance auditor when reviewing a simulation model. The models contain agreed upon Interchange Transactions between BA areas, but no details are provided to reflect individual Firm Transmission Service arrangements. In reality only the net-Interchange values between BA areas are reflected in the simulation models. C. R1.1.6: FE believes this requirement would be more accurately assigned to the Resource Planner or Load Serving Entity and not the Transmission Planner.

Organization	Question 1 Comment
	We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R1

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. However, the SDT has removed “including requirements of regulatory authorities and other legal obligations” since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

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.). The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

The SDT believes that the Transmission Planner/Planning Coordinator is responsible for incorporating this information into the System models. No change made.

Thank you for your response on Measures et al.

Organization	Question 1 Comment
IRC Standards Review Committee	(1) R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. Does this allow or require a PC/TP to include outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction as part of the Assessment? Such maintenance and construction schedules are made but may not be finalized over the planning horizon. Further, are planned outages to be treated as creating a “normal system condition” or is the planned outage a contingency from which system adjustments are made prior to subsequent events” (2) MOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. (3)What are “other data sources”?

Response: The SDT believes that the outages (if known) should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

Organization	Question 1 Comment
1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT understands that MOD-010 and -012 are impacted by MOD-011 and -013. The Planning Coordinator is not applicable - but has to utilize data provided by others such as in MOD-010 and -012.No change made. The SDT had removed the reference to "other data sources" under Requirement R1. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
TVA System Planning	The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies actually required in each year. The SDT stated during its June 30th Webinar that protection system equipment need not be explicitly represented in models, but had difficulty in determining adequate wording for the proposed sub-requirement. Because protection system action is described in R3.3.1, R3.3.4, R4.3.1, and R4.3.3 we suggest that protection system equipment be removed from the list in R1.1.2. If R1.1.2 is not removed, TVA is concerned about the level of resources that will be required to model these additional relay requirements in the one year allowed in the Implementation Plan. In bullet three of R1.1.2, are bus-tie circuit breakers to be represented in the models? Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models?
Response: The reference to "year" has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. See Requirement R1, part 1.1.2 comment above 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.). New technologies were removed from the Requirement R1, part 1.1.2 list (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Southern Company	The VSLs for Requirement R1 incorporates several sub-requirements but neglects one of the three components of the main requirement. Consider that R1 requires the TP and RC to (a) maintain System models, (b) use data consistent with certain MOD standards, and (c) simulate projected System conditions. Because the first component is not a part of the proposed VSL and the

Organization	Question 1 Comment
	purpose of this standard mentions a broad spectrum of System conditions, the recommendation is to add maintaining the system model into the VSLs for R1. R1.1.3 uses the terminology real and reactive Demand of Load. We suggest striking the word "Demand" because it refers only to real power. We recommend the the SDT limit R1 to load flow and stability models. Does R1 apply to short circuit models? If so does this imply that the short circuit model must be the same as the load flow model?

Response: The SDT revised the VSLs for Requirement R1 to align with the changes made to the requirement – note that the revised R1 does not use the word, "simulate."

The SDT has modified Requirement R1, part 1.1.3 (now part 1.1.4).

1.1.4 Real and reactive Load forecasts

The SDT believes that Requirement R1 also contains some requirements that are necessary for short circuit cases but R1 does not require the models to be the same, since different software applications may be used. No change made.

Organization	Question 1 Comment
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R1 Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should include discussion as to whether or not representations of generator forced outages are to be represented in the base case or if they are addressed through the sensitivity testing (Could add R1.1.7 Reasonable representations of unplanned generator outages.) Additionally, the standard is also silent on the treatment of system transfers, both internal and external, as to how they should be modeled in the base case. For some areas, their current practice is to include heavy system stresses in their base case, which leaves little for sensitivity testing. It is unclear if this practice works within this standard. R1.1.1 Priority comment R1.1.1 should be removed. It seems like there is an overlap between the requirements of this standard and Operational Planning studies with respect to known outages. Planned outages are addressed by our Operational Planning processes and Transmission Operating Procedures removing the need for this to be incorporated into Planning Assessments. In addition, outages are not generally known years in advance R1 Comment We do not understand what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.2 comment - Do we need to have the list of equipment to model? How do we model circuit breakers, etc? We recommend deleting the list. Make R1.1.2 simply read: R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.5 comment What specifically needs to be modeled under Interchange R1.1.6 comment This needs further definition or it should be deleted. It is not clear what a network resource required to supply load is. Does this refer to Network Resource per FERC LGIP?

Organization	Question 1 Comment
Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 (now part 1.1.3) has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.3** New planned Facilities and changes to existing Facilities Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as "energy transfers that cross Balancing Authority boundaries" while Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
System Protection and Transmission Planning Department	R1 the requirement to maintain System models for performing the studies is redundant with MOD-010, and should be moved to MOD-010. The phrase that requires model data used in Studies used for Annual Assessments be consistent with data submitted under MOD-010 seems OK. R1.1.2, a sub-requirement of R1.1, states that models for Planning Assessments shall represent "new planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon". Is this a requirement for maintaining a case representing every year of the near-term and long-term planning horizons (i.e. 10 cases)? We do not think that is what the SDT had in mind. If all that is required to remain cognizant of Facility In-Service dates so that topology is reliable, please so state. To make this read clearer, we suggest you take out the phrase for each year . Regarding bullet 5 of R1.1.2, does inclusion of Protection System equipment require modeling of all relays in dynamic studies? The NERC definition of Facility pertains to equipment energized at primary voltages, not Protective System equipment. We

Organization	Question 1 Comment
	suggest the Protective Systems be eliminated from this list. To make this read clearer, we suggest you delete text and bullet items following Transmission Planning Horizon. Regarding R1.1.2 bullet items: The bullets list examples of Facilities. This list is not needed, since the term Facility is already defined in the NERC Glossary. If you do not remove all bullets, then we warn you that the bullet "New Technologies" can be interpreted to cover a broad range of topics by an auditor and is not clearly defined by NERC, so we cannot visualize measurable documentation.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. No change made. Thank you for your response. The reference to “year” has been removed from Requirement R1, part 1.1.2 (now part 1.1.3). **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The bulleted list has been deleted.	
PPL Energy Plus	PPL agrees with the requirement that regulatory and legal requirements need to be respected in planning studies. Also, Requirement R1.1.6 appears to conflict with FERC Pro-forma OATT Section 30.4 in that Network Resource output should not be limited as this Requirement states.
Response: The SDT has removed “including requirements of regulatory authorities and other legal obligations” since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Western Area Power Administration	Since the modeling data used for the Planning Assessment is initially created and governed per Mod-10 & Mod-12 Standards, this requirement should be clarified to include maintain revisions of the modeling data required to perform the Planning Assessment

Organization	Question 1 Comment
	and not just "maintain system models for performing the studies needed to complete their Planning Assessment?.
Orlando Utilities Commission	-This section is very clear. Section R1.1.1 brings clarity to the question regarding planned outages.-The phrase Models shall use data consistent with MOD-010?, is the intent for the data to be “identical” to the data provided under MOD-10 and -12, or
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Tampa Electric	R1 Ensure that statement reflects that TP and PC are only responsible for their planning area. R1.1.2 Add transformers to list and clarify modeling of circuit breakers and protection system equipment. Models should reflect the effect of this equipment, not the actual equipment. R1.1.4 Models should only reflect firm transmission service that is expected to be utilized in the study case. Consider changing effective dates of all requirements to be the same date so that you do not have to meet two standards during the same time period.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement r4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R1 and M1: Consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). Please Clarify the phrase Models shall use data consistent with .MOD-010 is the intent for the data to be identical to the data provided under MOD-10 and MOD-12, or consistent meaning that the data might be older or newer depending on when the assessment took place vs when the data was submitted. R1.1 Consider changing Assessment (which does not include models) or re-wording to Models for performing the studies needed to complete the Planning Assessment shall represent:?R1.1.1 Brings clarity to the question regarding planned outages. R1.1.2: Consider adding "Transformers" to the list of facilities. R1.1.2, please clarify what the drafting team intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We sugges eliminating circuit breaker from the bullet list. R1.1.2 Protection System equipment this should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest eliminating Protection System equiptment from the bullet list. R1.1.4 Consider adding that is expected to be utilized in the study case scenario not all Firm Transmission can be included in all studies and are only used upon the availability of other resources . Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a	

Organization	Question 1 Comment
later date. The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1. The SDT agrees and has reworded Requirement R1, part 1.1. **1.1** System models shall represent: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
FMPA	R1, consider clarifying that it is not the TP or PC responsibility to independently verify the consistency of the System models for portions of the Bulk Electric System outside of the TP or PC planning area (related to not using data consistent with data submitted as part of MOD-010 and MOD-012, each TP and PC should not have to review the data submitted by those outside of its planning area, but only its own planning area). R1.1.2: Consider adding Transformers to the list of facilities. R1.1.2, please clarify what the SDTs intentions are for Circuit Breakers. Planning models used for power flow, dynamics and short circuit do not include circuit breakers. Modeling circuit breakers would cause convergence problems in the models due to that large number of zero impedance line sections. We suggest clarifying that the intent is to develop planned Facility Ratings in the models to reflect new Circuit Breakers, and to reflect the location and timing of circuit breakers in contingency lists, and not to model the actual circuit breakers. R1.1.2 "Protection System equipment should be clarified to only apply to system stability models. The modeling of protective relays should be caveated with as deemed appropriate. We suggest clarifying that the intent is, for power flow and short circuit studies, Protection System Equipment would be incorporated into Facility Ratings and the contingency list. And we suggest further clarifying that the intent is the same for Stability Studies, with the addition of modeling Protection System equipment that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment. R1.1.4 Consider adding "that is expected to be utilized in the study case scenario" not all Firm Transmission can be included in all studies and are only used upon the availability of other resources (for instance, if there are two firm point-to-point contracts in opposite directions across the same Interchange, both probably ought not to be modeled at the same time). Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet

Organization	Question 1 Comment
	two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit.
Response: The SDT had modified Requirement R1 to state that the Transmission Planner/Planning Coordinator are each responsible for maintaining System models for its respective area. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made.	
Progress Energy Carolina (PEC)	PEC would like clarification on the following: "Models for the Planning Assessment shall represent: Circuit Breakers, Protection System Equipment, etc." The clarification should state that the models do not have to explicitly include these elements as long as their effect can be modeled.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Gainesville Regional Utilities	Concerning the effective dates of R1 & R7, I suggest that you move them to be effective at the same time as R2 through R6 so you will not have to try to meet two standards during the same time period. Effective Date: Clarify how the effective date impacts which version of the standard (and it reference numbering) is to be used in an assessment just before (in cycle) a scheduled compliance audit. Suggest that the term "Corrective Action Plan" be retitled to "Improvement Action Plan" because the first implies that the situation is "wrong or incorrect" which may not be the case.

Organization	Question 1 Comment
Response: The SDT believes that certain steps need to be taken in succession to allow utilities to progress toward meeting the new requirements - while not placing an undue burden for utilities to meet all the new requirements at the same time. Also additional time is needed for many utilities to meet "raising the bar" requirements that may be required and which could take considerable lead time. No change made. The Effective Date of the requirements in force at the time the Planning Assessment is completed will dictate which requirements are the governing requirements. The SDT believes that the term "Corrective Action Plan" (a defined term) is sufficient due to lack of comments received from industry requesting this change. No change made.	
JEA	Reword R1.1.2. New planned Facilities and changes to existing and old planned Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon where such Facilities affect the electric connectivity and topology of the system or affects the accurate simulation of system disturbance response where practical. [Delete bulleted list]Add R1.2. Where it is not practical to model all Facilities composing the electric system connectivity and topology, consideration of those Facilities and their affect on the model simulations shall be documented in detail in the annual Planning Assessment where appropriate. This addition may not be necessary with rewording of R3.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The system models that are described in MOD-010 Requirement1, MOD-011 Requirement 1, MOD-012 Requirement 1, and MOD-013 Requirement 1 do not address all the bulleted items under R.1.2. Circuit breakers, protection system equipment and control devices are not modeled. Rather, the effect of these devices, such as circuit breaker misoperation, thermal overload, etc., on the transmission system are modeled. The wording of these bullets should be corrected to match what is actually modeled. Firm Transmission Service, listed in R.1.1.4, is not specifically addressed in MOD-010. Requirement 1 of MOD-010 states existing and future Interchange Schedules as data requirements for steady-state modeling and simulation. Models in the West do not model Firm Transmission Service as such. It is difficult to know what the Firm Transmission Service will be in the future. This is particularly true in regions where there is a predominance of merchant generation and proposals for the interconnection of new merchant generation. It is more reasonable to estimate the expected interchanges. The definition for Interchange Energy transfers that cross Balancing Authority boundaries describes the modeling requirement better that the definition of Firm Transmission Service The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruptions. The wording Expected Transfers" is used in R2.1.3 and R2.4.3. To maintain consistency, this term could be used in R.1.1.4 and could also be substituted in Table 1 for Firm Transmission. From a Planning perspective, since Firm Transmission cannot be determined from a study model. R1.1.4 and R1.1.5 should be deleted and replaced with a requirement to model expected transfers on interconnections with neighboring Balancing Authorities. For study purposes R.1.1.6 is not needed either. In the models, the load represented is served by the generators modeled. Network Resources are more in tune with local area studies that ensure that the network load can be served by the network

Organization	Question 1 Comment
	resources over available transmission. The words “including requirements of regulatory authorities and other legal obligations at the end of R1. does not need to be in the standard.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Interchange is defined in the NERC glossary as “energy transfers that cross Balancing Authority boundaries” while Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT believes that Requirement R1, part 1.1.6 is still required but it has been broadened. **1.1.6** Resources required to supply Load The SDT has removed “including requirements of regulatory authorities and other legal obligations” since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions	
SMUD	R1: The requirement should end after the words "shall simulate projected System conditions.”. The following words should be deleted as it results in a clause that is overly broad and does not specify clear and concise reliability requirements: "including requirements of regulatory authorities and other legal obligations".
Response: The SDT agrees and has changed Requirement R1 accordingly. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Progress Energy Florida, Inc.	For R1.1.2, PEF has the following comments:T-T Transformers, as major components of the BES, should be on this list.PEF does not object to the inclusion of Circuit Breakers on this list, provided that representation is not required in steady state load flow

Organization	Question 1 Comment
	cases. Breaker failure scenarios can be extensively studied in the steady state and stability realms by removing from service the transmission facilities that such a breaker event would initiate.PEF assumes that the inclusion of Protection System Equipment applies only to Stability Analysis. As for breakers, relay failure scenarios can be extensively studied in the steady state realm by removing from service the transmission facilities that such a relay event would initiate. Additionally, PEF also assumes that a comprehensive modeling of all Protection System Equipment (e.g. Transformer Sudden Pressure Relays, Bus Diff Relays, etc.) in Stability Analysis is not required, since only a limited amount of relaying in dynamic modeling is needed to adequately model the system with respect to what transmission/generation components would trip for a given event.A lack of specificity on the term Control devices leaves it open to wide interpretation. The SDT should, in detail and/or with examples, state what is intended. The term New technologies is only acceptable for inclusion if provision is made for the fact that Planning analysis software often lags behind the design industry in getting new technologies modeled such that Planners can analyze them. For R1.1.4 on Firm Transmission Service: PEF assumes that the SDT understands that some firm transmission service is not always modeled in every case, depending upon the economics and availability of alternate resources.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. 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.). New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Xcel Energy	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Arizona Public Service Co	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of

Organization	Question 1 Comment
	the devices or the effect of the removal of the devices only where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard. VSL: Under Severe VSL Column: The last sentence The System model did not simulate projected System Conditions as described in Requirement R1 is vague and should be clarified. What is meant by did not simulate. Is it referring to gross errors or something else? We recommend that Sever VSL be assigned only if the Transmission Planner failed to do the planning assessment. Hence it should not apply to R1 at all since R1 is only related to modeling accuracy.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service can actually be two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has replaced "simulate" with "represent" in the requirement, measure and under the Severe VSL category for Requirement R1. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate planning assessment.	
New Brunswick System Operator	It is not clear how TP and PC are to coordinate activities. If R6 provided direction on individual and joint responsibilities then R6 should be referred to in each of the requirements which require TP and PC coordination. The VSL and Measurement for requirement R1 appears focused the number of subrequirements represented in the model. Ideally the focus should be the impacts or error of the results if something is not properly represented. This shift in thinking will allow the planner to assess and focus on those subrequirements which are important to the study results. R1.1.1 Planned outage duration needs to be defined. For example, a planned outage for a year or more should be included in the

Organization	Question 1 Comment
	Near term assessment.
Response: Requirement R7 (formerly Requirement R6) requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT believes that having this as a separate requirement is sufficient. No change made. The SDT believes that the VSLs for Requirement R1 are already sufficient based on lack of industry comments. Note that the VSLs were modified to conform to the changes made to the requirement. Violation Risk Factors assess the impact to the BES of violating a requirement – not VSLs. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	
Western Area Power Administration	General, all-encompassing comment: The change in TPL Standards, while well intended, will be difficult to administer since it has taken a simple Performance Table and translated it into a legal-type document that is very complex to relate to the physical system for the planning and operations staff. The performance requirements must be related to the physical response characteristics of the interconnected system operation without depending on a legal advise for training my new transmission system planning staff. The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. I disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT believes that it is following the intent of FERC and NERC in creating a reliable Bulk Electric System by following the requirements in TPL 001-1. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The SDT has removed “including requirements of regulatory authorities and other legal obligations” since utilities already have to abide by such requirements.	

Organization	Question 1 Comment
R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Ameren	There may be a potential conflict between MOD-010 and MOD-012 and legal documents such as Interconnection Agreements e.g. IA may specify a capacity level that exceeds the reported test levels. In the case of such conflicts, it is not clear which one should rule. Suggest replacing circuit breakers in R1.1.2 with terminal equipment since circuit breakers are covered by Protection System Equipment. Consider adding a reference in R1 to NERC Reliability Assessment Guidebook version 1.2, pp 17-18 for use of a particular load forecast level for inclusion in the planning models. I n R1.1.2, revise the language to show that we need to also represent the existing transmission system, and not just changes to the existing system. In R1.1.2, Clarification is needed for the phrase for each year should signify only those years for which assessment work was performed, rather than each year of the Near-Term and Long-Term Transmission Planning Horizon. There typically is not a model built for each year of the Near-Term and Long-Term Transmission Planning Horizon. In bullet three of R1.1.2, it is not clear whether bus-tie circuit breakers to be represented in the models. Typically circuit breakers are included in the contingency definitions along with the protection system equipment used in the powerflow models. The number of zero impedance branches which can presently be modeled using PSS/E software is limited to 4000. Also, the number of buses included in the powerflow models would increase with additional breaker modeling. In bullet seven of Requirement R1.1.2, what "new technologies" are to be represented in the models” R1.1.4 Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. For example, should the standard define how to model wind farms (100% - off-peak and 20% on-peak, based on firm capacity from the wind generators, or other dispatch levels)?
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.	

Organization	Question 1 Comment
The SDT has revised Requirement R1, part 1.1.1 to include "existing Facilities". **1.1.1** Existing Facilities The SDT has deleted the reference to year. **1.1.3** New planned Facilities and changes to existing Facilities See response to Requirement R1, part 1.1.2 above. . 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.). New technologies were removed from the list in Requirement R1, part 1.1.2 (now part 1.1.3) and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Puget Sound Energy, Inc.	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
Tenaska, Inc.	It is not clear that Requirement R1 requires ALL existing generators, substations, transmission line, transformers, etc. to be explicitly modeled for steady state and stability studies. In fact, Requirement 1.1.6 could be interpreted to exclude various generators from the models if they are not contracted to supply load. A suggestion is to re-word R1.1 to read as follows:R1.1 Models for the Planning Assessment shall represent all existing generators, substations (including specific busses within a substation), transmission lines, loads, capacitors, reactors, and other equipment connected to the transmission system and shall

Organization	Question 1 Comment
	further represent the following:(continue with R1.1.1 through R1.1.6) A further refinement to R1.1.6 should also be considered as follows:R1.1.6 Committment and dispatch schedules of resources expected to serve Load for the specific model.
Response: The intent of the SDT is to model all bulk electric Transmission Facilities depending on the model used - whether for load flow, Stability, or short circuit. The SDT has modified Requirement R1, part 1.1 to provide better clarity on these models. **1.1** System models shall represent: Requirement R1, part 1.1.6 has been broadened while still incorporating Network Resources. **1.1.6** Resources required to supply Load	
Manitoba Hydro	Requirement Text: R1: What is meant by including requirements of regulatory authorities and other legal obligations? This phase should be deleted. Can NERC make it an obligation in a standard to follow regulatory authority and other legal obligations? The planner has scope to determine the projected system conditions, and if a local regulator mandated a requirement, the planner would be able to include it without this statement. R1.1.1: Only long duration known planned or scheduled outages that are expected to last over a system peak should be included in the scope of this standard. Known planned or scheduled maintenance outages should not be a part of the planning scope as they are short duration and are planned to be taken when system conditions allow. Suggest wording change to Planned outages of generation and Transmission Facilities with an expected duration of 6 months or longer, if specifically known. R1.1.2: Suggest deleting new technologies as it is unknown as to what this is. If the SDT wants to make the list all inclusive, add words such as shall include but not be limited to in the requirement wording. Circuit breakers are not specifically represented in the planning models in order to keep the number of buses within the program capabilities. However, the effect of the circuit breaker configuration is normally considered in the creation of contingency files. Can the drafting team confirm that circuit breakers do not have to be specifically represented in the model? The same comment can be said about protection system equipment. Some generic zone 1 modeling may be included but in general the effect of protection equipment is included in contingency files. R1.1.4 & R1.1.5: Firm Transmission Service represents a contract that the planner is obligated to include. Based on the NERC definition, Interchange is defined as Energy transfers that cross Balancing Authority boundaries. Including it as a requirement mandates system expansion for non-firm system usage. Interchange is already covered in the sensitivities (Expected Transfers) and should not be a specific sub requirement of R1.1.2. Perhaps simply documenting the value of the Interchange used in the Model is sufficient. This value may change in the sensitivity analysis conducted in R2.1.3 and the TP/PA will decide the level that they will plan on protecting.Measure: The measure requires the planner to provide evidence such as the System model. What further evidence is required to ensure the planner is using data consistent with the MOD standards, is simulating projected system conditions, and that the models represent the required information in accordance with Requirement R1? It is suggested to remove and shall simulate projected System conditions from the main paragraph of R1 and reword R1.1 to System models and contingency files for the Planning Assessment shall represent projected System Conditions including:

Organization	Question 1 Comment
	Requirement R1 is very vague, and the Measure refers back to R1. The MOD standards deal with the building of the model. Most planners provide data in accordance with the MOD standards for a regional model building process. These models form the basis for the models the TPs and the PC use. The R1could be more specific by requiring the PC/TP to provide rationale for the projected system conditions used, which might include the generation schedule assumed, the transfer conditions, why peak or off-peak is important, etc.. VSLs: The requirement is very generic in nature and leans on the MOD requirements. Verification of compliance to this requirement will be problematic. What will be required to prove that the data "is consistent with the data provided in accordance with the MOD-010 and MOD-012 and other data sources"? What are these other data sources?? R1 only stipulates that the planner shall "simulate expected system conditions", so how does one decided that the "model did not simulate projected System Conditions as described in R1" (severe VSL)?

Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months**.**

> **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months

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.). New technologies were removed from the equipment list in Requirement R1.1.2 since these are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.

Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

> **1.1.5** Known commitments for Firm Transmission Service and Interchange

Requirement R1 has been revised to replace "simulate" with "represent".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

Organization	Question 1 Comment
conditions.	
The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has removed "and other date sources" from Requirement R1. The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.	

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

Organization	Question 1 Comment
E.ON U.S.	R1.Delete and other data sources. Consistency with MOD-010 and MOD-012 standards is measurable and should suffice. Delete including requirements of regulatory authorities and other legal obligations. The term: shall simulate projected System conditions does not exclude the above. If there is some significance to this statement it should be an item in R1.1. R1.1.4.Firm Transmission Service is often sold for less than one year on an as available basis. Also, Firm Transmission Service may be sold on one system without a complete path. As stated, it appears necessary to include these examples in the Planning models. E.ON U.S. believes that there should be some limitations put on this requirement such as Long-Term Firm Transmission Service for a period of 5 or more years.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed "and other data sources".

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System

Organization	Question 1 Comment
	conditions. The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange
National Grid	Comments: R1: A. Priority Comment- There needs to be some direction provided on the initial conditions used in the assessment. This guidance should encourage the use of initial conditions that reasonably stress transfers across interfaces between companies, areas, regions, into load pockets, and out of constrained areas. The expectation that transfers are reasonably stressed for a variety of interface conditions will require the consideration of different generation dispatches, which goes beyond the single generator out of service requirement of the standard. If initial conditions consider reasonably stressed conditions, then sensitivity analysis is embedded in the process. If sensitivity is embedded in the process, it is unclear if additional sensitivity is still required by the standard. B. In the reference to regulatory authorities and other legal obligations it is suggested that the phrase be changed from "simulate projected System conditions including requirements of regulatory authorities and other legal obligations" to "include projected System conditions and requirements of regulatory authorities and other legal obligation." In common usage of terms, models are used to simulate system response, but models alone do not simulate the system. Violation Severity Levels:R1 Suggest changing the phrase "simulate projected System conditions as described in Requirement R1" to "include projected System as described in Requirement R1," consistent with the recommended change to Requirement R1. Errata:Delete the period after "R1" in the first bullet in the Data Retention section. R1.1.1 Priority comment ? R1.1.1 should be removed. - Planned outages are addressed by Operational Planning processes and Transmission Operating Procedures for up to two years ahead removing the need for this to be incorporated into Planning Assessments. - If outages are planned, but Operations can not accommodate them in real time, then the outages are cancelled. - Outages are not generally known beyond one to two years in advance. R1.1.2 Comment - We recommend deleting the list of facilities:- Circuit breakers are not modeled as elements in a power flow nor are Control Devices and Protection Systems - The list of facilities is not consistent with the definition of "Facilities" in the NERC GlossaryR1.1.2 should simply read:R1.1.2New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon. R1.1.3 Comment - The use of "real and reactive power" is prevalent within the industry, but R1.1.3 should be changed to "Active and reactive Demand of Load." When load is expressed as a complex quantity, active power is the real portion and reactive power is the imaginary portion. Thus for consistency, we should refer to active and reactive. R1.1.5 Comment What specifically needs to be modeled under Interchange" R1.1.6 Comment "This needs further definition or it should be deleted. It is not clear what a "network resource required to supply

Organization	Question 1 Comment
	load" is. Does this refer to Network Resource per FERC LGIP?

Response: Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. However the expected transfers under Requirement R2, part 2.1.3 are to further stress the system as a possible sensitivity analysis.

1.1.5 Known commitments for Firm Transmission Service and Interchange

The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has replaced "simulate" with "represent" under the Severe VSL category for Requirement R1.

R1 VSL	The responsible entity's System model failed to represent one of the Requirement R1, parts 1.1.1 through 1.1.6	The responsible entity's System model failed to represent two of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not use the latest data consistent with the data provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.	The responsible entity's System model failed to represent three of the Requirement R1, parts 1.1.1 through 1.1.6.	The responsible entity's System model failed to represent four or more of the Requirement R1, parts 1.1.1 through 1.1.6. OR The System model did not represent projected System conditions as described in Requirement R1.

The SDT agrees and had made this change under Data Retention.

Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months**.**

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in

Organization	Question 1 Comment
MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has modified Requirement R1, part 1.1.4 (former part 1.1.3). **1.1.4** Real and reactive Load forecasts Interchange is defined in the NERC glossary as “energy transfers that cross Balancing Authority boundaries” while Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” The intent is to include, but not be limited to these requirements. The SDT has revised Requirement R1, part 1.1.6. **1.1.6** Resources required to supply Load	
Entergy Services, Inc	Planned facilities and planned changes to existing facilities should be further defined to ensure facilities or changes that are unlikely to be constructed are not included in the models. See the proposed definition of planned facilities in the comments provided to question #8. Facilities included in the models should be only those projects that are committed to by the Transmission Owner or other users of the transmission grid. Consistent with the standards requirement to include only firm transmission service (R1.1.4), uncommitted facilites should not be included because an oversubscription of the grid could occur. R1.1: Please clarify what the SDT means by models for the Planning Assessment shall present, expecially for facilities such as circuit breakers, protection system equipment, and new technologies. Models also need to represent existing facilities R1.1.2: The phrase, for each year of the Near-Term and Long-Term Transmission Planning Horizon, should be revised to remove each year because there may not be studies in each year. R1.1.4: Firm Transmission Service - a single source can have transmission service to multiple sinks, and can be associated with transmission service in excess of the capacity of the source. There is a lack of clarity regarding the means by which Firm Transmission Service, a marketing term, is to be included in planning models. Not sure if this is applicable to Requirement 1 or 2.
Response: The projects that get included under the Corrective Action Plans are presumed to be the utility's best alternatives at that time in order to achieve compliance. The SDT understands that these alternatives may change over time - but these changes must be addressed under Requirement R2, part 2.7.6 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement r2, part 2.7.1 in the revised standard. The reference to year has been deleted. The SDT believes that all firm Transmission contracts should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Great River Energy	R1.1 is just repeating what should already be in the MOD-010 and MOD-012 requirements. Why re-iterate this in the TPL standard? The planners are expecting that the model building process will already include these components listed in R1.1 otherwise there wouldn't be a functional model. R1.1.1 may be the only thing that needs to be identified in R1 as any known long-term outage or retirement of a facility may have happened after the model building process. If R1.1 is kept I would suggest removing "Models for" so that R1.1 reads "The Planning Assessment shall represent: R 1.1.1 says the assessment shall represent planned outages if specifically known. It does not however distinguish the length of the outage to be considered. Should a 1 week maintenance outage in Year five be included? Should a 2 year complete rebuild outage lasting through year two and three be included? It is GRE's opinion that the SDT needs to add a comment about the length of the planned outage and its relevance to the assessment. In the Violation Severity Levels, R1 seems to be weak since any solved model should meet this requirement. Again this would seem to be more related to the MOD010 and MOD012 process. R1 should focus on documenting changes that are being preformed against the data that was submitted in MOD-010 and MOD-012 process.
Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has revised the language in Requirement R1, part 1.1 (now part 1.1.2) based on industry comments. . **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that the Severe level should be applied as noted in the VSL table since these cases are the basis for having an accurate Planning Assessment. No change made.	
BC Hydro	Comments: Consider just referring to the MOD series of standards, not specific individual MOD standards because the numbering of the MOD standards could change and additional relevant MOD standards could be added. Consider rewording the second sentence to read, The data and models shall meet all requirements of the MOD series of standards. The MOD standards should include the requirements of regulatory authorities and other legal obligations and need not be repeated in the TBL standard(s). R1.1.2: Consider changing to, New planned Facilities and planned changes to existing and changing the fifth bullet to read, Normal actions of Protection System equipment R1.1.3: Consider changing to, “End-use customer loads and generators [how small loads are aggregated should be covered in the MOD standards. A key point is that large industrial customers with significant generation that reduces their net peak demand should not be represented simply as a net load since that would not properly model the dynamic impacts of the load and

Organization	Question 1 Comment
	generation components]. R1.1.4: Consider changing to, Worst-case transfers on Firm Transmission Service Reservations. R1.1.5: Consider removing this requirement. It should be covered by R1.1.4 R1.1.6: Consider changing to, Generating units [the MOD standards should specify the details like how exciters, governors and associated control equipment must be modeled] Comment on M1: Consider changing to, using data consistent with the MOD series of standards, simulating. Consider just referring to the entire series of a particular standard, not specific individual standards because the numbering of the standards being referenced could change and additional relevant individual standards could be added.

Response: The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT referenced the specific MOD standards to ensure that the requirements were limited to those needed to complete the Planning Assessment. When the MOD standards are revised, this standard will be reviewed for conforming changes. The SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has reworded Requirement R1, part 1.1.1 to include existing Facilities.

1.1.1 Existing Facilities

The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part R3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

The SDT has modified Requirement R1, part 1.1.4 (now part 1.1.5) to state "Real and reactive Load Forecasts. Note that the generator modeling is addressed in the MOD standards.

1.1.4 Real and reactive Load forecasts

The SDT believes that all contracted firm Transmission should be modeled. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.

1.1.5 Known commitments for Firm Transmission Service and Interchange

See response for Requirement R1, part 1.1.2 above.

The SDT believes that the specific MOD standards should be addressed in this TPL 001-1 draft since they deal directly with the modeling requirements necessary for creating base cases. No change made.

Organization	Question 1 Comment
Midwest ISO	Generally the Midwest ISO agrees with FirstEnergy's comments regarding this requirement. However, if the SDT insists on keeping this requirement as is then we propose the following corrections specific to each requirement. Specific Comments for Requirement 1: A) Under R1 there is language that references "other data sources; can the SDT please offer some clarification on what "other data sources are to be Could other data sources be Tariff requirements" B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. This does not allow or require a Transmission Planner or Planning Coordinator to include outages due to maintenance and/or due to construction programs where certain facilities are out of service during various phases of construction, as part of the Assessment. For this reason, we believe the following language for R1.1.1 would improve this requirement: Planned outages of generation and Transmission Facilities if specifically scheduled or planned for. D) Under R1.1.1 we suggest adding sub-requirement R1.1.7 Generation dispatch patterns deemed appropriate by the Transmission Planner and Planning Coordinator. This clarifies that when building System models, generation dispatch is part of the model building process. E) Under R1.1.2 there is uncertainty around the language of New planned Facilities. We offer the following definition for Planned Facilities to be added to the definition section of this standard and further added to the NERC Glossary of Terms: Planned Facilities Generation and Transmission Facilities that are expected to be implemented with an in service date prior to the plan year being studied. F) Under R1.1.2 a bullet should be added for Relay Loadability Limitations. The standard requirements for relay loadability are included in PRC-023-1.

Response: The SDT has removed the language "and other data sources".

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.

Organization	Question 1 Comment
• **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. Requirement R1, part 1.1.6 now states Resources required to supply Load. **1.1.6** Resources required to supply Load Requirement R1, part 1.1.3 covers new planned Facilities and changes to existing Facilities. **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. Relay loadability is covered under Requirement R3, part 3.3.3. No change made.	
PJM	In R1, why require a Planning Coordinator AND a Transmission Planner to maintain models for the same area Concern with the words - for each yearin R1.1.2. Does this mean that a case for each year, at least, will need to be produced? Will five, one for each season and a light load, each year need to be produced R1.1.5 is not clear. Is the Interchange exclusive of Firm Transmission Service as mentioned in R1.1.4 Maybe -non-firm transmission service-- is clearer.
Response: Requirement R7 requires the Transmission Planner and Planning Coordinator to determine and identify joint responsibilities. The SDT has modified Requirement R1 to state that the Transmission Planner and Planning Coordinator are responsible for maintaining System models for their respective areas. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has revised Requirement R1, part 1.1.2 (now part 1.1.3) to delete the reference to “year".	

Organization	Question 1 Comment
1.1.3 New planned Facilities and changes to existing Facilities The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
American Electric Power	Under R1.1.2. Add Transformers, otherwise, revise Transmission Lines to read Transmission Facilities. Also under R1.1.2., add Series Reactors and Capacitors as a distinct category of facilities from Reactive Power devices that include shunt capacitors and reactors, and Control devices that include phase angle regulating and variable frequency transformers, FACTS devices, and other power electronics. These additions would further clarify the types of facilities that should be included, and these comments are made in full recognition that the introductory sentence to R1.1.2. contains the wording such as.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7. The SDT has also revised this requirement to remove 'such as'.	
ITC Holdings	Comments: We question the value of R1.1.1, which requires the inclusion of transmission or generator outages if..known, in a planning standard. If an outage puts you in a compliance deficiency for the duration of any outage, would you be fined for such an instance? Category P6 contingencies should cover these outages and not require a separate requirement such as R1.1.1. This requirement could also make an entity subject to fines for long term outages needed to upgrade or replace equipment as part of a CAP for other category violations. If this requirement is kept, it should be restricted to very long term outages and exclude those outages needed to complete CAPs for other violations. R1.1.6 requires the use of Network Resources to supply load. For many planning studies, particularly beyond the five year window, the capacity additions needed to supply load are frequently unknown. Since there are no requirements or guidelines for assuming what and where these resources will be, assumptions will have to be made regarding the needed resources. Additionally, existing network resources could be retired or re-designated to serve other load. It is unclear as written exactly what would be a violation of this requirement if known network resources are not sufficient to serve projected load. Finally, with the advent of market power, would a dispatch utilizing this type of dispatch be considered a violation of this standard.
Response: The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.	

Organization	Question 1 Comment
The SDT has revised Requirement R1, part 1.1.6. to include Resources required to supply Load. **1.1.6** Resources required to supply Load	
Northern Indiana Public Service Company	Under R1.1, insert, "as applicable" after "represent". Since R1 covers steady state, short circuit and dynamic models, data requirements should be applicable to the specific model. Representation of circuits breakers, protection system equipment and control devices is not typical of steady state model inputs.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note ‘c’ in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.	
Minnesota Power	A) Under R1 there is language that references other data sources; can the SDT please offer some clarification on what other data sources are to be? Could other data sources be Tariff requirements? B) Again under R1, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R1 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. C) Under R1.1.1 it is required that models represent planned outages of generation and transmission facilities, if specifically known. However, the requirement does not distinguish the length of the outage to be considered. Should a one week maintenance outage in Year Five be included? Should a two-year complete rebuild outage lasting through the entire years 2 and 3 be included? The SDT team needs to add a comment about the length of the planned outage and its relevance to the assessment. D) R1.1 is repeating what should already be in the MOD-010 and MOD-012 requirements. Is the inclusion of these elements in the TPL standard redundant? The planners expect the model building process will already included the components listed in R1.1, otherwise there would not be a functional model. If R1.1 is kept, we suggest removing the “Models for” so that R1.1 reads “The Planning Assessment shall represent:”
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. The SDT has deleted the language “and other data sources”. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.	

Organization	Question 1 Comment
Mitigation Time Horizon The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The SDT believes that the outages should be modeled to insure the system reliability during the outage durations. If a transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. All performance criteria would then apply to that new base case. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date. The SDT has reworded Requirement R1, part 1.1. **1.1** System models shall represent:	
LADWP	For R1.1.4 the requirements should be based on "expected transfer" instead of "firm transmission service". When projecting into future, the term "firm transmission service" is meaningless because transmission service contracts can be changed overnight. Using "firm transmission service" as a base would also exclude any new contract that are not considered in the study. It is very short-sighted to plan new transmssion facilities only based on "firmed transmission services". R1.1.2 is very confusing. What is a new technology? Is it something we don't know? If we know what it is, is it still a new tchnology? If we don't know, how do we model it? Also, we do not model individual circuit breaker but the effect of the circuit breakers; same apply with control devices or protective system equipment. Need more clarity. In general, a laundry list of items to be represented is a bad idea because it gives the impression that anything not on the list does not need to be modeled.
Response: The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is “the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption.” Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	

Organization	Question 1 Comment
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.). New technologies were removed from the list in Requirement R1, part 1.1.2 and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Platte River Power Authority	R1.1.2. "....for each year of the Near-Term and Long-Term..." Models for each year of the 10 years in the planning horizons are not developed in our Region. Please clarify your intention. R1.1.2. 3rd bullet - "Circuit breakers (or the effects of)" R1.1.2. 4th bullet - "Protection System equipment (or the effects of)" R1.1.2. 5th bullet - "Control devices (or the effects of)" R1.1.2. 6th bullet - "New techonologies (or the effects of)" R1.1.4. "Firm Transmission Service (or expected transfers)
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities The SDT has removed the equipment list under Requirement R1, part 1.1.2 (now part 1.1.3). Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange	
MAPPCOR	R1 - what it means to include requirements of regulatory authorities and other legal obligations. Even if some version of this language is kept in the final standard, it seems to belong in R2 rather than R1. R1.1.1 - should remove the word specifically since it means nothing. Only known long-term outages of generation and transmission should be required to be modeled. R1.1.2 in the first line should have the word studied to avoid confusion, to read "New planned Facilities and changes to existing Facilities for each year studied of the "?

Organization	Question 1 Comment
	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: : The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within their respective areas for performing the studies needed to complete their Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has deleted 'if specifically known'. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The SDT has deleted "year". The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
Idaho Power	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement r3, part 3.3, Requirement r4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange.	

Organization	Question 1 Comment
1.1.5 Known commitments for Firm Transmission Service and Interchange	
Turlock Irrigation District	TPL 001-1 R1 could potentially result in a WECC auditor having to determine compliance with requirements of regulatory authorities and other legal obligations, beyond the scope of its expertise. TID proposes that if that language is to be retained, it shall be assumed that the requirements of regulatory authorities and other legal obligations are being simulated unless those other entities have formally found the member to be in violation of their requirements or obligations.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
New York Independent System Operator	R1.1.1 requires that models shall represent planned outages of generation and transmission facilities, if specifically known. The standard should be clarified to state whether it allows or requires a PC/TP to include as part of the Assessment outages due to maintenance and due to construction programs where certain facilities are out of service during phases of construction. Such maintenance and construction schedules are established but may not be finalized over the planning horizon. Further, the standard is not clear whether planned outages are to be treated as creating a normal system condition or as a contingency from which system adjustments are made prior to subsequent eventsMOD 10 and 12 are based on requirements determined by the RRO in MOD 11 and 13 respectively. Is this appropriate? Further, the PC is not an applicable entity in MOD 10 and 12. Moreover, the standard should define other data sources. R1.1.2. states that models for facilities such as circuit breakers and protection systems should be represented. Comment - The list of facilities should be deleted for the following reasons:- it is not needed;- the NYISO does not model circuit breakers, Control Devices, and Protection Systems;- it is not consistent with the definition of Facilities in the NERC Glossary.
Response: The SDT believes that the outages should be modeled to insure the System reliability during the outage durations. If a Transmission element outage occurs during a specified time, then the new base case for that time period would result with that element out of service pre-contingency. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months. **1.1.2** Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. The Planning Coordinator is to still use the information provided under MOD-010 and -012. The SDT has removed "and other data sources". **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to	

Organization	Question 1 Comment
complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.	
Duke Energy	Revise R1.1.2 to include the phrase to be studied as follows: New planned Facilities and changes to existing Facilities for each year to be studied of the Near-Term and Long-Term Transmission Planning Horizon, such as :
Response: The SDT has deleted "year". **1.1.3** New planned Facilities and changes to existing Facilities Existing Facilities are now shown under Requirement R1, part 1.1.1. **1.1.1** Existing Facilities	
Tucson Electric Power Company	The language in R1.1.2 needs to be clarified. Many of these facilities are not explicitly included in the models in the base cases (circuit breakers, protection system equipment, control devices). The language should be clarified to require modeling the effect of the devices or the effect of the removal of the devices where it is expected to impact the study outcome. An alternative, instead of specifically listing elements, make a general statement that the models should include those elements required in MOD-010 through MOD-013. If an element is missing, double jeopardy could result due to a violation of the applicable MOD standard and this TPL standard. Clarity is needed to explain the difference between R1.1.4 and R1.1.5. Expected interchange can be reasonably projected, but information on Firm Transmission Service is not always known or reasonably projected for future cases. For consistency with the 2nd bullet under R2.1.3, R1.1.4 should refer to expected transfers rather than Firm Transmission Service. With this change, R1.1.4 and R1.1.5 would be redundant and one should be deleted. We disagree with the inclusion of the words including requirements of regulatory authorities and other legal obligations at the end of R1. Entities already are required to do this. It does not need to be included in the standard.
Response: The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. The SDT believes that additional modeling requirements not presently contained in the MOD standards are necessary for Transmission Planning purposes. The SDT has incorporated these additional requirements with the intent that they will be removed from the TPL standard when they are incorporated into the MOD standards at a later date.	

Organization	Question 1 Comment
The SDT believes that transfers and Firm Transmission Service are actually two separate items since Firm Transmission Service is "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	
Independent Electricity System Operator	1. R1: What modeling/simulation is envisaged by the phrase requirements of regulatory authorities and other legal obligations? Note that this condition is not included in the measure or the VSL, making its compliance (whatever it is) irrelevant. If it is indeed a needed condition, then it should be measured and included in the VSL language under the Severe condition. Further, we suggest replacing simulate with incorporate since R1 deals with building of the system model that will be used to perform simulations governed by Requirement R2. Moreover, we do not think this requirement (to simulate projected System conditions including requirements of regulatory authorities and other legal obligations) belongs to R1, which is a requirement to develop the system model. R2 is the requirement for conducting Planning Assessments which include simulation using the model. We suggest moving this requirement to R2 upon making appropriate changes, where necessary to address our comments on the wording. 2. We recommend introducing applicable before regulatory authorities. 3. R1.1.2: suggest to add Transformers. 4. R1.1.5: suggest to change Interchange to Interchange Schedules or Interchange Transactions. 5. We agree with the VRF, Time Horizon, Measures and VSLs, other than the requirements of regulatory authorities and other legal obligations noted above.
Response: The goal is for the responsible entity to build a realistic simulation, and the entity has to comply not only with the criteria in the TPL standard's tables, but also with other non-NERC regulations. However, the SDT has removed "including requirements of regulatory authorities and other legal obligations" since utilities already have to abide by such requirements. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.	

Organization	Question 1 Comment
The SDT has changed the word "simulate" to "represent" in Requirement R1. The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard. Requirement R1, part 1.1.5 has been revised to include known commitments for Firm Transmission Service and Interchange. **1.1.5** Known commitments for Firm Transmission Service and Interchange Thank you for your response on VRF et al.	
Kansas City Power & Light	R1 states that the models used in these studies shall be consistent with data provided through MOD-010 and MOD-012. The data submitted for these are updated on a schedule provided by the RRO and not necessarily reflective of any emerging changes that may have occurred between the MOD data collection cycle. The requirement should allow for exceptions to allow the most recent information to be included in the TPL studies.
Response: The SDT has modified Measure M1 to use the latest data available. **M1** Each Transmission Planner and Planning Coordinator shall provide evidence, in electronic or hard copy format, that it is maintaining System models, using the latest data consistent with MOD-010 and MOD-012, including items represented in the Corrective Action Plan, representing projected System conditions, and that the models represent the required information in accordance with Requirement R1.	
ReliabilityFirst Corporation	R1.1.1 requires to include Planned outages of generation and Transmission Facilities, "if specifically known" Should the generation be capitalized? Suggest changing it to "All planned Generation and Transmission facilities should be modeled. R1.1.2 Use of the word "such as" is not very clear and may not be enforceable. There are some size limitations in the study tools and it may not be possible to model all circuit breakers. Last three bullets are very hard to model and these are not consistent with MOD-010 and MOD-012. I am not sure what "New Technologies" mean. Does this require a model for each year? This contradicts the requirements in Sections R2.1-R2.1.1, R2.1.2 and R2.2. Suggest changing this to read "New planned Facilities and changes to existing Facilities for Near-Term and Long-Term Transmission Planning Horizon as described in Sections R2.1-R2.1.1, R2.1.2 and R2.2." Modeling of Protection Systems, Control Systems requires new data collection effort and falls under Section 1600 of NERC Rules of Procedure. The list does not include Transformers.Suggest removing Protection System equipment and Control devices from the list and adding another sub-section which states "Models should reflect the limitations imposed by Protective Devices and Control systems characteristics. Define "New Technologies"

Organization	Question 1 Comment
	R1.1.3 Here it is better to include the Type of Forecast (50/50 or 90/10). A reference NERC Reliability Assessment Guidebook can be included here.

Response: Generation is not a defined term itself in the NERC glossary - thus it does not need to be capitalized in Requirement R1.1.1. Requirement R1, part 1.1.2 has been revised to include known outages of generation or Transmission Facilities with a minimum duration of 6 months.

1.1.2 Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months.

The SDT has revised R1.1.2 to remove "such as". The SDT has removed the equipment list under Requirement R1, part 1.1.2. Transmission lines, generators, and reactive power devices are already included in MOD standards. Circuit breakers, Protection System equipment, and control devices are not typically modeled - the impact of these devices are typically simulated and thus these are already included in Requirement R3, part 3.3, Requirement R4, part 4.3, and in header note 'c' in Table 1. New technologies were removed from the list and are already covered in the Corrective Action Plan under Requirement R2, part 2.7.1 in the revised standard.

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.).

The SDT has deleted "year".

1.1.3 New planned Facilities and changes to existing Facilities

The SDT does not believe that a reference is needed to the NERC Reliability Assessment Guidebook since most utilities are using at least a 50/50 Load forecast as a minimum. No change made.

2. Requirement R2 — Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The industry had many comments on Requirement R2 but for the most part, the questions were requesting clarification. The SDT has changed a number of the parts of this requirement with the major changes being: part 2.1.4 and part 2.4.3 on sensitivities, additional clarification on part 2.2 for the Long-Term Transmission Planning Horizon and the addition of a new part 2.7.2 on multiple sensitivity deficiencies. The full list of changes is:

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

2.1.4 (previously 2.1.3) For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.1.5 (previously 2.1.4) When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.2 The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

2.2.1 A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

2.5 (new) The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

2.6.1 (previously 2.5.1) For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 (previously 2.5.2) For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

2.7 (previously 2.6) For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7 (previously 2.6) bullet 2: Installation, modification, or removal of Protection Systems or Special Protection Systems

2.7.2 (new) Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.7.5 (previously 2.6.4) If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The

Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.

2.7.6 (previously 2.6.5) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

2.8 (previously 2.7) For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

2.8.2 (previously 2.7.2) Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status.

2.9 (previously 2.8) The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1, part 2.2, part 2.4, part 2.5, or part 2.7	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1, part 2.2, part 2.4, or part 2.7.

Organization	Question 2 Comment
Dominion - Electric Transmission	R2.1.3 - Dominion suggests that SDT needs to be more specific on which of thevariations to include. Also for the last bullet, the SDT needs to clarify the duration ortiming of planned transmission outages (in relation to Planning horizon). R2.4.1 - While we appreciate the intent of introducing induction motor modeling in simulations, this is a difficult proposal in actual practice. The question of how much of the load is comprised of induction motors and what is a reasonable/practical model has been around now for over twenty years yet is still not resolved satisfactorily. For example, we have heard several experts declare the CLOAD model is inadequate for study. NERC needs to take the lead in developing appropriate models for the widely used simulation software and a methodology for determining load composition prior to requiring induction Load modeling in dynamic simulation studies. Additionally, this requirement states that Aggregate System Load model is acceptable to represent the dynamic behavior of induction motor Loads. Our interpretation is that such aggregate models shall be inserted by the Planners at the time of study, over a specific study area as determined by TP, and these models are not to be represented in the interconnection-wide (i.e. ERAG/MMWG) dynamics base cases. If ERAG/MMWG dynamics base cases are populated with such aggregate load models, the dynamic simulation cases could become very difficult to solve, if not impossible. R2.8 - Dominion does not see any purpose in reporting largest consequential load loss. This is not easily calculated, and

Organization	Question 2 Comment
	would vary from year by year, season by season. R2.9 - Dominion requests further clarification. Is the intent of this requirement to develop criteria for maximum allowable non-consequential load loss prior to requiring a corrective action plan or to just calculate such a load loss where it is permitted in Table 1?

Response: Part 2.1.3 (now Part 2.1.4) has been revised to provide greater clarification. It is intended that the Planning Coordinator or the Transmission Planner will select the variation to include in the sensitivity studies.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

The last bullet in Part R2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, nuclear power plant refueling, generating unit maintenance, etc.

Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Organization	Question 2 Comment
Northeast Power Coordinating Council	It is recommended to replace the phrase prepare with conduct and document in the first sentence.R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon

Organization	Question 2 Comment
	identified in R2. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 With respect to spare equipment strategy; this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Remove the wording (such as a transformer). What constitutes "spare equipment strategy"? Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of the transmission system constitute a valid "spare equipment strategy" R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]" An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive

Organization	Question 2 Comment
	language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment. It is strongly recommended that the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement would then be deleted. The use of System Off-Peak Load is too general. Is the intention to have the system minimum load used here? Because of the seasonal differences in equipment ratings, seasonal peak and off peak (minimum) loads should be analyzed.

Response: The SDT was not able to locate the word "prepare" in the first sentence of Part 2.1.1. However, Requirement R2 states, "Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses". The SDT assumes that the comment was meant for this sentence. The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes the requirement to document assumptions and results. No change made.

The SDT disagrees that the requirement to evaluate Year One and year two is inconsistent with the Time Horizon in R2. The new definition defines Year One as the first year that the planner is responsible for assessing. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of risk in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.4 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of

Organization	Question 2 Comment
merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement, which contains "determined to be material by the Planning Coordinator or Transmission Planner", is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning Coordinator or Transmission Planner on what is "material". Material has been deleted from the requirement. Part 2.6.2 and 2.6.3 have been removed. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur in more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to	

Organization	Question 2 Comment
Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6.4 (now 2.7.5) allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The recommendation that "the standard should consider not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1" will include also the multiple Contingencies, for which loss of Non-Consequential Load is allowed in the existing TPL Standards. While the sentiment is laudable, it may not be practical. No change made. The use of System Off-Peak Load is intended to be general to allow the Planning Coordinator or the Transmission Planner to use their best judgment suited to the study area, since the System must be able to meet performance requirements over all demand levels. The Planning Coordinator or Transmission Planner is not precluded from investigating more System conditions than are required in this standard. No change made.	
Transmission Planning	R2.1.4. COMMENT: For the analysis to reflect the contingencies in Table 1 (P0 through P7 plus Extreme Events) is excessive. R2.5.2. COMMENT: The 20 MW change listed in bullet items are extremely small to larger transmission systems and by themselves would be unlikely to change BES response. As drafted, requirement 2.5 may be interpreted to preclude the use of any previous study in which the base case is not identical to the current planning case. It is recommended 2.5.2 be rewritten as follows; For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. R2.6.2. COMMENT: What is considered a project initiation date is it implying a construction start date, or the first time that it was identified as a mitigation plan? Additionally, R2.6.2 and R2.6.3 are not necessary because a Corrective Action Plan, by definition, includes an "associated timetable for implementation". Recommend deleting this requirement. R2.8. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and the value of this data is questionable. Recommend deleting this requirement. R2.9. COMMENT: Why is this data collection a requirement? The effort required to determine this data is substantial and

Organization	Question 2 Comment
	the value of this data is questionable. Recommend deleting this requirement.

Response: Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

While the SDT appreciates the concern, the proposed revision could be interpreted as removing the threshold for minimum change in generation. Part 2.5.2 has been revised as Part 2.6.2 to include an alternative threshold to be based on the study area's installed generation capacity.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Organization	Question 2 Comment
SERC Engineering Committee Planning Standards Subcommittee	R2.1: In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. R2.1.4: In Requirement R2.1.4, recommend that the requirement be revised as follows: "When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. R2.4.1: In Requirement R2.4.1, it is suggested that it be reworded to the following: "System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Organization	Question 2 Comment
	R2.5.1:With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.6.2: In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. R2.8: Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.9: Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss does not impact reliability.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to reflect your suggestion.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

Organization	Question 2 Comment
Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Modesto Irrigation District	On pages 6 and 7 under sections R2.1.3 and R2.4.3, I think the magnitude of the variations in the conditions asked for in the sensitivity cases, should be defined and not left to the analyst to decide. On page 8 under Section R2.5.2, examples of material changes for generation are given, but no examples for transmission changes. Shouldn't we include examples of material transmission changes, too Comments: Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES R2.8 and R2.9 load loss comment. We don't agree with R2.8 & R2.9. What reliability purpose is served by these requirements?
Response: The items in Parts R2.1.3 (now Part 2.1.4) and 2.4.3 are intended for use as guides. NERC Standards must allow room for discretion of the Planning Coordinator and/or Transmission Planner who are closer to the issues in their respective areas. In Part 2.5.2 the SDT removed the examples related to the generation changes and therefore have not added examples of transmission changes. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
OPUC	2. Requirement R2 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments: A: Short circuit of over-stressed breakers is already addressed in Table 1.Ex1: P2-3,4 (Internal Breaker Fault),Ex2: P4 (Stuck Breaker while attempting to clear a fault). B: In R2.1.4 Table 1, it is unclear how transformer contingency analysis can be aggregated or batched. It is also still unclear

Organization	Question 2 Comment
	whether corrective action plans are required solely to meet performance requirements for sensitivities.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. This is not the same as the examples cited. Part 2.3 has been revised to provide greater clarity.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6 has been revised and included as Part 2.7 to state that Corrective Action Plans do not need to be developed solely to meet the performance requirements for a single sensitivity run. Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity).

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

Bonneville Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). R2.1.1: Peak load modeled for the near term planning horizon may not be Year one or year two. Therefore, R2.1.1 should be revised to say System peak load for one of the five years. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer.

Organization	Question 2 Comment
	This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5 has been revised and references to the 20 MW change have been deleted.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees

Organization	Question 2 Comment
that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R2: Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.Augment R2.6.5 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status . . . Augment R2.7.2 to include annual verification of the continued validity of the Corrective Action Plan because the value of implementation status is dependent on the status of continued validity. MRO NSRS suggests this text that is similar to R2.6.5: Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Remove R2.8. MRO NSRS does not know of any reason why the investigation and inclusion of the largest Consequential Load Loss caused by any P1 or any P2 events is needed to assure adequate BES reliability. In addition, all events involving Consequential Load Loss are studied, not just the largest load loss (see R3.3.1).
Response: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.6.5 and 2.7.2 have been revised and included as Parts 2.7.6 and 2.8.2 respectively to reflect your suggestion. **2.7.6** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures. **2.8.2** Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status. Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written, it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	

Organization	Question 2 Comment
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	1. R2.1.4 Loss of 2 transformers is itself a very severe contingency. However, when it is combined with R2.1.4 (spare equipment strategy) it can lead to a triple contingenecy which is unnecessarily severe and has an extremely low probability of occurrence. We recommend that the requirement be deleted from the standard. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid.

Response: Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

Organization	Question 2 Comment
2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years. R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? In the subrequirements of R2.1.3 and R2.4.3, the use of the word "timing" is unclear. Consider using in service date or schedule for. " In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also suggest that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to:oIn Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead

Organization	Question 2 Comment
	time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. How would adequate lead times be determined" In Requirement R2.1.4, recommend that the requirement be revised as follows: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience the possible unavailability of the long lead time equipment. Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new requirements? R2.3 Insert the phrase "one year of after the word addressing. In Requirements R2.3 and R2.4, do we need a reference to Requirement R2.5 for the past studies" Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.1: It is not clear how much Load must have a dynamic model. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable. Is a NERC drafting team addressing these issues to determine an industry standard? Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: Regarding Requirement R2.6, it is suggested that the word "modeled" be added as follows: For Planning Events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System modeled shall continue to meet the performance requirements in the tables. Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. The Corrective Action Plan shall: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital

Organization	Question 2 Comment
	project must be included (or completed) in the Corrective Action Plan? With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Similar to the draft MOD-026-1 standard, this period should be 10 years. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest Consequential Load Loss impact reliability? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments?? R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. R2.9: One cannot determine the maximum permissible Non-Consequential Load Loss for every Planning Event. First of all, this should not be a requirement, as it is, for those events that do not even cause Non-Consequential Load Loss. Secondly, to obtain the maximum permissible value, one would have to stress the system in some way until one of the performance requirements are violated. That is an unreasonable stipulation and cumbersome to perform such an analysis.

Response: Requirement R2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning

Organization	Question 2 Comment

Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: 1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. 2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. Therefore, the SDT declines to make the change as suggested.

Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to clarify the word "timing".

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

The SDT reviewed Part 2.1.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and

Organization	Question 2 Comment

the term, "studies described in Parts 2.1.1 and R2.1.2" should be sufficient to avoid confusion. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made.

The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment. No change made.

Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required:

Part 2.4.1 has been revised to reflect your suggestion. In addition, Requirement R2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 is a sub-part of Part 2.4, and so should also carry the same limitation.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and R2.4.2" should be sufficient to avoid confusion. No change made.

Part 2.6 has been revised and included as Part 2.7 to reflect your suggestion. The third bullet in Part 2.6.1 is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns, but the SDT disagrees that the timeframe should be changed to 10 years.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

Organization	Question 2 Comment
	to demonstrate that the results of an older study are still valid. Part 2.5 has been revised to reflect your suggestion. **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies. Use of generation tripping not precluded within the Standard and the maximum duration for operating procedures in Corrective Action Plans is not addressed within the standard. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. If Contingencies occur inside one utility that affect facilities in another utility, the Planning Coordinator or Transmission Planner for the utility, whose system is impacted would be responsible for performing the annual Assessment for those contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.
FirstEnergy Corp	The standard provides prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment, but other steady-state load modeling assumptions such as constant impedance load and constant current load can be utilized. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. To this end, we suggest a new sub-requirement R2.1.1 be placed ahead of the existing R2.1.1 that parallels R2.4.1 and indicates the TP should document its load modeling assumptions for steady-state simulations. Specific comments, Requirements of R2A. R2.1: The requirement incorrectly references R2.6 which should be a reference to R2.5. B. R2.1.1: We propose that the SDT adjust requirement R2.1.1 to annually require one current year Near-Term and one Long-Term study, with the Long-Term study required to alternate between year six and year ten every other assessment year. This would reduce the workload on the industry and cover the mid-point transition period between the Near-term and

Organization	Question 2 Comment
	Long-Term horizons that the standard team believes needs some attention. We find the requirement to perform two Near-Term studies and one Long-Term study each year overly burdensome, in light of the increased workload caused by sensitivity analysis for each steady-state and stability review that is required. FE believes that one current year study within each time period should suffice in being able to interpolate and extrapolate results to cover the entire assessment range; especially when supplemented with qualified past study results. C. We offer the following comments related to requirement R2.4.1: 1. In the last round of comments we made the following comment "This requirement should be separated into two requirements as it covers two distinct topics; a) peak load study for one of the near-term years and b) dynamic load modeling." The SDT responded "...This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels." Apparently, the SDT did not agree with our recommendation to split the requirement as no change was made in this regard. Therefore, as written the standard in R2.4.2 (stability study of the Off-Peak Load level) seems to imply that the appropriate modeling of dynamic behavior of loads, including consideration of induction motor loads, is NOT required for the Off-Peak Load stability study. Please clarify or confirm this view of R2.4.2. 2. R2.4.1: We are still of the opinion that the word "appropriately" is vague and only serves to add confusion within this requirement. It's recommended that "appropriately" be struck from the requirement. 3. R2.4.1: In Draft 3, the SDT added text to this requirement that states "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable" to clarify that a detailed dynamic Load model is not required at each bus. We understand this to mean that the model is not expected to try and replicate the dynamic behavior of individual end-user Load characteristics and that general approximations for a customer class(es) (residential, commercial or industrial) simulated at a given load bus is acceptable. 4. Based on our comments C.1 through C.3 we propose the following requirement language: R2.4.1. System peak Load for one of the five years.R2.4.2. System Off-Peak Load for on of the five years.R2.4.3. Load models used for stability analysis shall represent the dynamic behavior of Loads, including the behavior of induction motor Loads. The study shall document assumptions made for representing the dynamic behavior of Loads, based on the following load classes - residential, commercial and industrial. D. R2.5.2: For clarity and readability we propose to insert the word "that" between the words "and would" so the requirement reads "...intervening period and that would impact ...". E. R2.6.1: This requirement indicates that an entity's Corrective Action Plans list situations where Table 1 Performance Criteria are not met and the associated actions needed to achieve required System performance. What if the actions and plans associated with newly identified deficiencies (current year studies) are not yet fully known and require further analysis and a more detailed study of various options. Would it be acceptable for a TP to indicate that the planned solution is To Be Determined? This could be a likely scenario for a long-term planning horizon study which may identify a number of deficiencies which require more detailed analysis to determine the appropriate solution. F. R2.6.2: We believe this requirement is overly prescriptive in requiring a project initiate date. The standard should not question an entity's project management but stay focused on whether or not the Correct Action Plan was put in place in a timely fashion. We propose that the team strike from this requirement the reference to project initiation date and focus on

Organization	Question 2 Comment
	whether or not Corrective Action Plans were completed in a timely manner to ensure Table 1 Performance Criteria is met. Additionally, project initiation date is pertinent to a operating procedure solution that is allowed by the standard. R2.6.4: We support requirement R2.6.4 but suggest the word "prudent" be struck from the text of the requirement as it can be subjective and open for debate. G. R2.7: This requirement introduces additional Corrective Action Plan requirements beyond what is stated in R2.6. FE proposes that the SDT restructure the two requirements into a single requirement (and sub-requirements) focused on Corrective Action Plans. H. R2.8: Does this requirement apply to sensitivity simulations? If so, it has limited applications to only those sensitivity analyses that consider variations in load such as a higher forecast (90/10), or increased reactive load (sensitivity to poor power-factor loads), etc. The SDT should consider clarifying the intent of the requirement if each current year study as well as their corresponding sensitivity simulation model(s) is intended to have this information documented within the assessment report. I. R2.9: We ask the SDT to confirm or correct our understanding that the requirement is asking about a TPs criteria for maximum allowable non-consequential load drop and NOT the maximum non-consequential load shed required to meet performance criteria for a particular contingency evaluation. We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R2

Response: The language does not preclude the documentation of the steady state Load model used because steady state assumption of Load model is a degree of conservativeness. See header note b. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

As written, Requirements R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. So the suggestion to alternate between year six and year ten every other assessment is already allowed as written. No change made.

In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per Part 2.4.1,

Part 2.5.2 has been modified and included as Part 2.6.2 and the “intervening period” language has been deleted.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the

Organization	Question 2 Comment
Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.6 has been modified and included as new Part 2.7. Part 2.6.1 requires a Corrective Action Plan be developed to enable the System performance requirements in Table 1 and Part 2.6 states that “revisions to the Corrective Action Plans are allowed in subsequent assessments but the System shall continue to meet the performance requirements in Table 1”. This allows the Planning Coordinator or Transmission Planner to develop a Corrective Action Plan that can consist, for example, of a number of potential alternative solutions, and, the Corrective Action Plan can be revised as the study continues. ‘Prudent’ has been deleted in Part 2.6.4 (now Part 2.7.5). **2.7.5** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Part 2.7: Short circuit duty Assessment has been revised for clarity and included as Part 2.8. **2.8** For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: Parts 2.8 and R2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
IRC Standards Review Committee	(1) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as normal system condition or as having a contingency from which system adjustments are to be made prior to subsequent events. (2) Under R2.5 ?Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub requirement R2.5.2 states that for SS, SC, or stability analysis; the PRESENT system model shall not include any material changes, such as “.Does this mean that past studies may be used to support planning assessments as long as there are no material changes to the present system model” If so, that would be an impossible scenario to recreate.
Response: In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the “normal” (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the	

Organization	Question 2 Comment
	performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5.2 is intended to allow the use of past study if the System that is being modeled for Assessment today has not materially changed from the one modeled in the past study for the study area. While changes are expected to occur between planning cycles, not all changes have significant impacts on System performance. For example, if the load growth in an area has not changed significantly, there is no change in the Transmission System and no addition of new generation, and then a case can be made that the past study can be used to support a new Assessment.
TVA System Planning	Do not understand the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1. Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term? Since R2.3 short circuit analysis is a new raising the bar requirement, should the implementation plan for this be for 5 years like the other new raising the bar requirements? Further clarification is needed in R2.4.1 concerning load models that appropriately represent the dynamic behavior of loads. Is a NERC drafting team addressing these issues to determine an industry standard? If contingencies occur inside one utility that affect facilities in another utility, which utility is responsible for running these studies during the annual assessments? In R2.6.1, is there any limit to the time duration that a SPS and/or operating procedures can be used in the CAP? In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. In R2.6.1, installation or modification of Protection Systems or Special Protection Systems are now allowed as part of the Corrective Action Plan. Should undervoltage and underfrequency load shed also be allowed in the Corrective Action Plan? In R2.9, does the requirement require the maximum non-consequential load that can occur for contingencies in Table 1 or does it require just the maximum that a utility will allow on its system? Suggest clarifying permissible or perhaps using similar language as found in R2.8. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. In R2.1, change the reference to requirement R2.6 (at the end of the last line) to R2.5. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would

Organization	Question 2 Comment
	cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend add the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.6.2, what constitutes a "project initiation date," and how will it be used? Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies Strike the words supplemented with and insert the word or R2.3 Insert the phrase one year of after the word addressing. In the subrequirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. In R2.6, does the Corrective Action Plan need to show all possible alternatives to fix a problem that has been identified - or does only one solution need to be shown for a problem?

Response: As written, Requirement R2 and Part 2.1.1 provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year Planning Assessment, and to assess other years in addition to those identified in Part 2.1.1. So the suggestion is already allowed as written. No change made.

The SDT does not feel that Part 2.3 raises the bar as entities should have been performing these studies all along. No change made.

Part 2.4.1 requires only that the Load model appropriately represent the dynamic behavior of Loads. It is up to the Planning Coordinator and Transmission Planner, who are closer to the issues in the planning area to determine the application of the Load models. No change made.

If Contingencies occur inside one utility that affect Facilities in another utility, the Planning Coordinator or Transmission Planner for the utility whose System is impacted would be responsible for performing the annual Assessment for those Contingencies known to cause the impact. A certain amount of coordination will need to occur between the utilities. The parties can then mutually agree upon a Corrective Action Plan.

Part 2.6 has been revised and included as Part 2.7 in the new version. In the fifth bullet in Part 2.6.1, the duration for use of an operating procedure is at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible to implement Transmission reinforcements in some locations.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.

Organization	Question 2 Comment

Part 2.9 has been deleted.

In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

The SDT believes that Requirement R2, part 2.8 (now part 2.9) supports the objective of ensuring BES reliability by ensuring that the largest expected amount of Consequential Load Loss is reported in an open, transparent process. Part 2.9 has been clarified.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

In Part 2.1 it is envisioned that not all parts of the studies on which the Assessment is to be based can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met.

Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised to reflect your suggestion.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

Organization	Question 2 Comment
	• Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part.2.6 does not specify how the Corrective Action Plan is written, it only requires that there is a plan to correct the potential problem identified in the Assessment. Therefore, it can be a number of alternatives or a single definitive alternative as long as the potential problem is addressed.
Exelon Transmission Planning	There are large amounts of resources required to perform the volume of studies required, including the dynamic and steady state sensitivities, extreme studies, and one-year lead time equipment spares. Many of these studies ultimately do not require additional consideration or reinforcement and have low threshold triggers, such as a 20 MW generation change. Performing these studies will be very burdensome to many TPs and result in few, if any, reliability benefits. We believe that the TP should be given more flexibility to allocate planning resources to areas of maximum benefit. The Spare Strategy in R2.1.4 is still not well defined. What types of equipment are included? How would a one-year lead time element be determined for consideration in this requirement? In R2.4.1, we recommend changing appropriately represents to a dynamic model appropriate for the type of stability study being performed? The TP should be allowed to perform only those specific stability studies needed and pertinent to its system. The same can be said about the dynamic load model. Differing interpretations are possible. We suggest changing the last sentence in R2.4.1 to .., a Load model shall be used which appropriately represents..An aggregate System Dynamic Load model which represents the overall dynamic behavior of the Load is acceptable. In 2.1.3 and 2.4.3 strike Expected from the phrase Expected transfers. Expected transfers should already be in the base case. In R2.5.2, the determination of a Material change is an engineering judgment issue and it should not be categorically defined here. There may be more significant material changes than a 20 MW increase in generation that would be better to study. In the phrase, For steady statesuch as generation or transmission additions/removals, or topology changes and would impact the study area, it is suggested to change would to could and impact the study area to significantly change the previous study results. The term should not be Corrective Action Plan, which implies a violation of a requirement. Suggest changing this term to Future Reliability Plan. What is the intended use for reporting the largest consequential and maximum non-consequential load loss amount and event? This would be a potential security concern if made public. There is a similar concern with the extreme event analysis. In 2.6.2 please define Initiation Date. While we appreciate your previous consideration of this comment, it is still not clear what this means. Is this the date of mitigation identification, regulatory approval date, construction start date, equipment procurement date, etc? If this is a commonly understood term not requiring a formal definition, could you then please

Organization	Question 2 Comment
	provide that definition in your response? If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified.

Response: If there are specific requirements in the standard that you feel would require the Transmission Planner to allocate their resources a certain way then you need to supply those specifics. As it stands, the SDT feels that the Transmission Planner can allocate resources any way they want. The standard does not dictate how they should meet requirements. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have an agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.4.1 has been revised to address your concerns.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to strike "Expected Transfers" from Parts 2.1.3 (now Part 2.1.4) and 2.4.3. Parts 2.1.4 and 2.4.3 are sensitivity cases to be examined, which should cover conditions different from the base case. In any case, the Planning Coordinator or Transmission Planner are only required to examine one of the items from the list, and has the flexibility to choose other sensitivity cases if changes in expected transfer is not applicable.

Part 2.5.2 has been modified and included as Part 2.6.2. The SDT declines to change the term "Corrective Action Plan" to "Future Reliability Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. The SDT does not believe that this requirement represents a security concern as rewritten.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

Organization	Question 2 Comment
events in Table 1. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The comment – "If there is going to be a requirement to report on each contingency that results in non-consequential load loss it should be specified" does not reference any specific Requirement and therefore, the SDT can't respond. No change made.	
Southern Company	The Lower VSL describes a scenario where the TP or PC fails one or both of two particular sub-requirements. This language does not reconcile how failure of two sub-requirements is consistent with failure of only one of the same requirements. The recommendation is to restructure the VSL such that it is invoked when either sub-requirement is violated (not when both are violated). Generating unit stability has now been combined with system stability to be just one category - Stability. Previously, the shelf life of generating unit stability studies was indefinite -only needed to be restudied when system changes required it. Now the maximum shelf life of Stability studies is five years. Does this mean that generating unit stability studies must be repeated every five years whether system changes make it necessary or not? Requirement 2.3 stating that the short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon. It is not clear if the intent of the requirement is to study every year within Year One and year five. A statement similar to R2.1.1 Year One or two and year five for steady state analysis would be helpful. Some clarification is needed for R2.3 on the term Near-Term. Requirement 2.3 stating that "the analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. What interrupting devices are included? Would the circuit breakers be enough? Moreover, the term System short circuit model is used for the first time (and the only time) here for the entire document. It is very common to use a different short circuit model for short circuit analysis while the steady state and stability analysis use different System models (power flow models). Some clarification is needed. R2.8 and R2.9 use the term megawatt "Demand". This is redundant. We suggest striking the word demand.
Response: The Lower VSL for Requirement R2 has been revised.	

R2 VSL	The responsible entity failed to comply with Requirement R2, part 2.9	The responsible entity failed to comply withRequirement R2, part 2.3 or part 2.8.	The responsible entity failed to comply with one of the following parts of Requirement R2: part 2.1,	The responsible entity failed to comply with two or more of thefollowing parts of Requirement R2: part 2.1,

Organization	Question 2 Comment			
			part 2.2, part 2.4, part 2.5, or part 2.7	part 2.2, part 2.4, or part 2.7.

Part 2.5.1 has been revised and included as Part 2.6.1 to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

The SDT declines to revise Part 2.3 to include short circuit analysis for one of the years in the Near-Term Transmission Planning Horizon because Part 2.3 only requires that a Planning Assessment be performed. Past studies can be used to support the Planning Assessment.

Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The “megawatt” Is the qualifier for “Demand”. The SDT believe it is clear as written. No change made.

Organization	Question 2 Comment
United Illuminating	R2 Comment We recommend replacing the phrase “prepare” with “conduct and document” in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn’t the standard state (such as a transformer, generator or power electronic device) and not just

Organization	Question 2 Comment
	(such as a transformer). R2.2 Comment We suggest replacing the phrase “a current System peak Load study” with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today’s rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: “For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase “in the tables” is used. We suggest using more definitive language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase “as well as an in-service date” should be modified to read “as well as a target in-service date”. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year’s assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year’s assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for

Organization	Question 2 Comment
	non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

Response: The SDT does not think that replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes a requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.

Organization	Question 2 Comment
	• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either a study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Requirement R2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was revised but not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Parts 2.5 .1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined. While the SDT appreciates the concern that a 20 MW generation addition can be small compared to a large System, a NERC standard needs to be clear as to the applicability. A requirement which contains "determined to be material by the Planning Coordinator or Transmission Planner" is not clear. Therefore, changing from 20 MW to "material" will also have to require justification from the Planning

Organization	Question 2 Comment
Coordinator or Transmission Planner on what is "material". Material has been deleted. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Louisiana Energy and Power Authority	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a

Organization	Question 2 Comment
	planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Part 2.6 as shown. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.	
System Protection and Transmission Planning Department	R2 - The term "Stability Analysis" is used frequently in the standard, but is not clearly defined. Based on an IEEE paper ("Definition and Classification of Power System Stability," Kundar, et al) there are 5 different categories of stability analysis: 1)small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. Does the writing committee intend to make the analysis of all these types of stability issues mandatory? I recommend inserting a new definition into the standard for stability as follows: "Stability Analysis - The study of the bulk electric power system's ability, for a given initial operating condition, to regain a state of operating equilibrium after being subjected to a physical disturbance. There are 5 accepted categories of power system stability: 1) small signal angle stability; 2) transient angle stability; 3) frequency stability; 4) large disturbance voltage stability; and 5) small disturbance voltage stability. While there are situations that exist that require small signal angle and voltage stability analysis, only transient angle stability, frequency stability, and large disturbance voltage stability analysis are generally relevant to system planning performance assessments. R2.1.4 is a new requirement directing studies to consider impacts of spare equipment strategy. Does this require the TP to run scenario analysis without certain transformers? It is not clear what is required. How many spare transformers are required? What reliability level is acceptable? R2.1.4 The one year cut-off seems arbitrary. One MONTH may be unacceptably long in some cases. Instead of one year or more, we suggest the requirement state an extended time period.

Organization	Question 2 Comment
	R2.2. The wording on this requirement is not clear. Is it trying to say that a long-term (5-10 year) peak loading study is required to be performed annually R2.2: What is meant by the term current System peak Load study A powerflow study performed under expected peak-load conditions? Or a forecast of peak loads? R2.3 A short circuit analysis requirement is now added to Planning Assessment requirements. Short circuit analysis appears to be in the standard to document adequate ratings for interrupting equipment. That would be the purpose of short circuit studies we perform. If there are other intended meanings, then additional detail is needed. R2.3 We do not agree that a short circuit analysis needs to be conducted annually. The requirement for a new short circuit duty study should be driven by changes in the system, as is done for powerflow study work. In short, until system changes are made, we would not anticipate higher fault duties, and there would be no reason to rerun studies. R2.4.1 requires dynamic load models. Development of dynamic load models is ongoing, and therefore will need a much longer implementation period than the steady state portions of the standard. We are not sure two years will be enough. It depends partly on pending work that is not under our control.R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, R5 When text of a Standard Requirement includes the phrase such as or could include, then gives a list of possible choices, we take it to mean “just one of these items, or none of these, or something not listed here”. In other words, such as lists are really non-required, non-interpretable, non-measurable options. They should not be included in requirements. Lists such as these belong in transmittal notes and associated SDT commentary, not in Compliance Standard Requirements. R2.5.2 Limits such as “addition/deletion/change to a group of generating units . . . which total 20 MW or greater. are not always appropriate. Appropriateness of Generation netting with load should depend on system size and engineering judgment, not artificial limits. The suggestion list following generation changes could include: should be eliminated. R2.6.2. For the Near-Term Transmission Planning Horizon, include both a project initiation date as well as an in-service date? The assessment report should not require a full project development just a description of what is required to provide adequate service within specified operating criteria. The term project initiation is not clear. Requirement R2.6.2 should be eliminated. R2.8. The Planning Assessment shall provide the largest Consequential Load Loss (megawatt Demand) and the associated event caused by any P1 event and any P2 event in Table 1. is complicated, and may require new modeling software capability to comply. Software vendors would develop this capability. Why is this required? What is the expected benefit to system reliability?

Response: The SDT disagrees that the Standard should include a definition of Stability analysis because it is covered in Requirement R2. “Stability analysis” is not a defined NERC term and is not intended to be defined as in IEEE; however, it does not conflict with the IEEE definition. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won’t last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, and may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its system, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than

Organization	Question 2 Comment

one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the “normal” (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2 has been revised to provide greater clarity. The standard will require that a study for one year within the Long-Term Transmission Planning Horizon be conducted. The Planning Assessment can be supplemented by past studies.

> **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

Part 2.3 has been revised to provide greater clarity. In addition, Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. The Assessment is to be supported by a current or past study. Therefore, annual short circuit study is not required if no material change has occurred.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. In addition, the SDT was not able to locate the phrase “such as” in Requirement R2.4.1. There were two places in Requirement R2 that this phrase appears (Parts 2.1.4 and 2.5.2). In both instances, what follows were examples and not requirements.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with

Organization	Question 2 Comment
Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Part 2.8 is intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PPL Energy Plus	The standard appropriately recognizes that the planning horizon must be as long as the longest lead-time system upgrade, typically 8+ years for a new line. However, while Requirement 2.2.1 states this, it could be more clearly stated. Requirement R2.5.2 should be clarified to point out if the TP has discretion or if the 20 MW is binding. Requirement R2.6.4 should require TP's and PC's to post on an OASIS to assure easy access by affected parties to information on what is "beyond the control of these organizations. Please retain Requirements 2.8 and 2.9 as these are good measures of the quality of the plan produced by the planners.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 (now Part 2.6.2) has been revised to address your suggestion. Both bullets included references to 20 MW have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. The SDT declines to require a specific venue for the Planning Coordinator and/or Transmission Planner to post the information regarding Part 2.6.4. The way information is shared should be left to the individual entities involved in accordance with Requirement R7, included in the new version as Requirement R8. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and finds that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PacifiCorp SRP Arizona Public Service Co	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this

Organization	Question 2 Comment
Southern California Edison Company Pacific Gas and Electric Co, California ISO Idaho Power San Diego Gas and Electric Co	could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
NV Energy	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).R2.1.3 should be modified to remove the last bullet point. Transmission outages should be a part of operational study work not planning study work. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be based on a percentage of the study area'sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent,

Organization	Question 2 Comment
	among other things, on the types of load being served. It very well may be a case by case situation.
Western Area Power Administration	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault).The last bullet under R2.1.3 - "Planned duration or timing of Transmission Outages." does not belong in a long-term planning standard. These-type of seasonal outages are studied and implemetation plans are derived as part of the TOP Standard requirements. In the WECC - this is also covered by the seasonal studies carried out by the Operating Transfer Capability Policy Committee (OTCPC) study groups. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement - OR simply delete this spare equipment requirement. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event if it is documented? R2.9 should be deleted. This requirement is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.

Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Organization	Question 2 Comment
2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.5 has been revised and included as Part 2.6 as shown. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Western Area Power Administration	Short-circuit studies as related to maintaining adequate protection devices and systems are normally performed either by a specific System Protection Group/Department or System Maintenance Department and should not be in this requirement, but Post-Transient Analysis to mitigate voltage collapse scenarios should be included (includes R2.5.1 & R2.5.2). Also, System Protection including mitigation of short-circuit duty above installed facilities capabilities or for new planned facilities are already covered by the PRC Standards and need not be included and duplicated in the TPL Planning Standard such as in R2.3 & R2.7.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop Corrective Action Plan is needed. As such, they are not specifically related to new planned Facilities. Requirement for Post-transient voltage collapse is included in Table 1, Header note (a), which states "Voltage instability, cascading outages, and uncontrolled islanding shall not occur." No change made.	
Tampa Electric	R2.1 should state R2.5 at the end of requirement instead of R2.6 R2.1.4 Consider revising to only include P0-P2 contingencies. R2.5.1 please clarify whether the 5 years is from the beginning of the assessment or end of the assessment. R2.6 Consider changing the terminology for "Corrective Action Plan" to "Transmission Plan" R2.8 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this information is substantial and does not benefit the BES. R2.9 Please clarify the reason for this requirement. This is not necessary for reliability and the effort to collect this

Organization	Question 2 Comment
	information is substantial.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.6, the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Organization	Question 2 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4 - Please consider revising this for the analysis to include only Contingencies P0-P2 in Table 1. Alternatively we suggest moving this requirement to be under sections 2.1.3 and 2.4.3 and treated as a sensitivity. R2.5 ? This requirement is very valuable in clarifying that past studies can be used and what criteria needs to be met for them to be used. However it is not clear if all new studies could be met using past studies (e.g. a small system with very few changes year to year) of if some sub-requirements require a new study every year, with past studies only used as supporting information. If the intent is that some sub-requirements can not be met with past studies, then consider making that clear through a foot note or a list under Section 2.5 listing which study requirements may depend only past studies that are still current.

Organization	Question 2 Comment
	R2.5.1 Please clarify if the 5 calendar years is from the date the assessment is "finished" or the date the study process for the assessment begins. R2.5.2 the identified 20 MW threshold is extremely small and would be doubtful to change the response of the BES. This requirement could also be interpreted that a previous study where the base case is not identical to the current planning case could be used. Please consider the following proposed language: For steady state, short circuit, or Stability analysis: the present System model shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period that would impact the study area. (not show the list) R2.6 - Requiring sensitivities but not requiring that they meet specific performance requirements is a sound approach.R2.6 requires a corrective action plan when performance will not be met in the simulations. However, if an entity has already planned a needed facility and/or operation steps for a given conditions, the simulations will not show any deficiencies and therefore no corrective action plan is required. The term Corrective Action Plan implies that the situation is wrong or incorrect, consider changing the approach to be to require an entity to have a planning and Operations plan, Improvement Action Plan?, or simply a Transmission Plan that includes all facilities planned for the BES and descriptions of conditions where an operational process is being used. R2.6.1 (Bullet 2) This requirement should also account for the removal of a Special Protection Systems: Installation, modification or removal of Protection Systems or Special Protection Systems?. R2.6.4 This is an excellent addition R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria? We suggest eliminating this requirement.

Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 & 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the

Organization	Question 2 Comment
System is expected to experience due to the possible unavailability of the long lead time equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.5.1 the 5 years should be measured from the completion of the past study to be used to support the current Planning Assessment. However, Part 2.5.1 has been revised and included as Part 2.6.1, which will allow the use of studies older than 5 years if a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. In Part 2.6 (now Part 2.7), the SDT declines to change the term "Corrective Action Plan" to "Transmission Plan" because the Standard only requires the System performance to meet requirements. If a System meets requirements, then a Corrective Action Plan would not be necessary. An entity can still choose to install Transmission reinforcements for other reasons, but they would not be required by this Standard. Although additions of Protection Systems and Special Projection Systems are usually associated with projects to enable the System to meet performance requirements, the second bullet in Part 2.7 has been modified to include removal of Protection Systems or Special Protection Systems to provide greater clarity. **2.7 bullet 2:** Installation, modification, or removal of Protection Systems or Special Protection Systems Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
FMPA	Incorrect reference shown at the end of R2.1. The appropriate reference should be R2.5. The end of the first sentence of R2.3 should have a reference to R2.5. The end of the first sentence of R2.4 should have a reference to R2.5. R2.1.4, what does (t)he analysis shall reflect the Contingencies identified in Table 1 mean? Is the intention similar to sensitivities, where there is no direct requirement to meet the performance standards of Table 1? If so, why not include loss of a long lead time Facility followed by other contingencies one of the Sensitivities and not have a separate sub-requirement for it? Or, is the intention that the TP and PC must meet the performance requirements of Table 1 considering the outage of a long lead time Facility? We hope that the intent is not to require Entities to be able to meet the performance requirements

Organization	Question 2 Comment
	of Table 1 assuming a long lead time Facility out of service. If that is the intent, then we believe that only Contingencies P0-P2 in Table 1 ought to apply to Requirement R2.1.4. Otherwise, Requirement R2.1.4 would require building transmission to triple contingency (N-3) criteria. Contingency P3 requires building transmission to a single contingency plus a generator outage (a double contingency that has the same performance criteria requirements as single contingencies). Since generators are long term lead Facilities that no one that we know of carries spares for, R2.1.4 as written would mean that Contingency P3 becomes two generators out of service with system adjustments followed by another contingency (N-3). This would have the (possibly unintended) consequences of significantly reducing long-term firm ATC since utilities will likely use TRM to account for the potential for long-term outages. If meeting the criteria of Table 1 is the intent of the SDT, then a potential way to address this is to restate R2.1.4 to state that only P0 through P2 (zero and single contingency) apply to R2.1.4.If meeting the performance criteria of Table 1 is the intent of the SDT for R2.1.4, then we also believe that R2.1.4 should also only apply to the EHV and not the HV system. Yes, when a major piece of equipment such as a transformer fails, it could be out for a long period of time; however, a transformer failure is far less probable than an over-head transmission line failure (e.g., a transformer failure is in the range of a once in 50 year event, whereas a transmission line fails probably once a year or once every other year, almost two orders of magnitude difference). A major 500 kV/230 kV autotransformer failure will have a far larger radius of impact than a 230 kV/138 kV autotransformer meant to serve the local area, giving additional support to purchasing a spare transformer for the 500/230 kV auto (EHV system). A small utility with only one or two 230 / 138 kV autos does not have sufficient justification to purchase a spare autotransformer due to the very low failure rate and the much more localized purpose of the transformer. If the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then the standard would essentially cause many small utilities who cannot justify spare autos to plan to serve only load and significantly reduce ATC in the planning horizon. Based on the lesser impact of HV connected autos as compared to EHV connected autos, and if the intent of the SDT is to meet the performance requirements of Table 1 for R2.1.4, then we would recommend that, for auto-transformers, R2.1.4 should only be applicable to EHV connected auto-transformers. R2.8 Please explain the reason for this requirement. The effort required to collect this data is substantial and does not have any benefit to the BES. R2.9 Please explain the reason for this requirement. It seems to cause Entities to develop performance criteria for themselves for Multiple and Extreme Contingencies that are not in Table 1. The effort required to collect this data to compare against any self-imposed criteria is substantial and does not have any benefit to the BES. The requirement will result in inconsistency across North America. There is also no discussion of what happens if a Multiple or Extreme contingency is shown to exceed the Entity's self-imposed criteria, is the Entity then non-compliant? If so, what if the Entity simply changes the self-imposed criteria?

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference.

Parts 2.3 and 2.4 have been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned

Organization	Question 2 Comment
generation and Transmission Facilities in service which could impact the study area. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Progress Energy Carolina (PEC)	PEC believes that "R2.1.1. System peak Load for either Year One or year two, and for year five" is unneccesarily prescriptive. PEC recommends eliminating the Year One or year two addition. PEC believes that R2.1.4. concerning an entity's spare equipment strategy is overly conservative. The standard should only require N-2 deep planning and not N-3. PEC believes that for R2.4.1 "a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads" should be clarified to include "as appropriate" clause. Induction motor load modeling should not be required for all dynamic studies. PEC believes that for R2.5.2. The language "For steady state, short circuit, or Stability analysis: the present System model 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" needs to be made more clear. The important point is that material changes must be modeled if they have occurred. Also the 20MW threshold is far too small to be material. PEC believes that R2.8. and P2.9 are unnecessary and should be removed.

Organization	Question 2 Comment
Response: Requirement R2, part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Requirement R2, part 2.1.1. No change made. Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 allows the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
CPS Energy	As written, is it the intent of Requirement R2.1.4. to escalate the contingencies in Table 1 from "N-1" to "N-2" and "N-2" to N-3" for long lead-time replacement equipment, such as autotransformers and GSUs? If so, we feel that this requirement is

Organization	Question 2 Comment
	overly burdensome that will result in unnecessary expense to the customers. In Requirement R2.4.1., what is the intent of the second sentence if an aggregate system load model is acceptable? We feel that the second sentence should be removed. In Requirement R2.6.2., we feel that statement of the project initiation date has no benefit and should be removed as a requirement. The required in-service date should be adequate. We do not believe that there is any benefit to reliability by documenting the Consequential and Non-Consequential Load Loss data required by Requirements R2.8. and R2.9.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. In Part 2.4.1, the intent for the second sentence is that if more accurate Load Model is available it should be used. The standard should not inadvertently disallow improved Load modeling. In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MidAmerican Energy Company	MidAmerican commends the SDT for all its hard work on this standard. MidAmerican offers the following comments on R2: MidAmerican believes that the second sentence of R2.3 as written will result in unnecessary modeling for the required short

Organization	Question 2 Comment
	circuit analysis. MidAmerican recommends that the sentence The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study area. MidAmerican recommends that R2.3 be changed by deleting the words any and could and replace with the words materially. In this way, the sentence would read, They analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with generation and Transmission Facilities in service which materially impact the study area. Requirement 2.5 is too confining and is complicated and unnecessary. MidAmerican asks that the requirement be deleted in its entirety. Alternatively, if the SDT does not agree with deleting all of R2.5, then MidAmerican asks that the SDT consider deleting the R2.5.1. MidAmerican believes R2.4 will ensure that analysis is fresh by requiring a certain number of studies be conducted for certain years in the planning horizon. Why add the requirement for no older than 5 calander years? With the R2.4 and the material requirements in R2.5.2 shouldn't that be more than enough to ensure that the analysis is fresh enough to support the assessment?? If R2.5.2 is not deleted, the words and interconnected to the Bulk Electric System should be added behind 20 MW or greater. Requirement 2.6.2 requires the project initiation date. MidAmerican recommends that the SDT delete the requirement to provide this date as an initiation date is not related to system reliability. If the SDT believes it is critical to get this date, then the SDT should define it. Does it mean when engineering starts, when it is decided to proceed, or something else? At a minimum, MidAmerican believes that the SDT should add the word expected behind largest to avoid unnecessary compliance issues for an unexpected event, and clarify that R2.8 and R2.9 are not required for sensitivity cases.

Response: Part 2.3 has been revised to provide greater clarity. However, the SDT declines to make the changes suggested because Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt, and develop a Corrective Action Plan as needed. As such, they are not specifically related to individual new planned Facilities.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Deleting Part 2.5 would leave no guidance on when past studies can be used to support current Assessment. This can increase work load. Part 2.5 has been revised and included as Part 2.6 as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

In our last meeting the SDT agreed to revise Part 2.6 (and included it as Part 2.7) and project initiation date is no longer required.

Organization	Question 2 Comment
2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Deseret Generation & Transmission	R2.5.2 For Past studies to be used in the Planning Assessment, the suggestion that the addition of a 20 MW generator would disqualify those past studies is way too restrictive. It should be left up to the Transmission Planner to evaluate the applicabililty of past studies and the two sub bullets should be removed and replace with a general statement about past studies should adequately represent the present system to be used in the Planning Assessment. Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the “largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event” if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.5.2 has been revised and included as Part 2.6.2 to address your concerns. The references to a 20 MW threshold have been deleted from the revised standard. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to	

Organization	Question 2 Comment
demonstrate that System changes do not impact the performance results in the study area. Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Part 2.7.2 has also been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Northeast Utilities	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments.

Organization	Question 2 Comment
	R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity study just to meet the requirement of the standard does not add value to the assessment. R2.1.3 Comment - What should be the time duration for the bullet that reads Planned duration or timing of Transmission outages R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard needs to allow Non-Consequential load loss for P3 & P6 events when spare equipment strategy is incorporated in the testing. An example of such an event, that non-consequential load loss should be acceptable, would be a long-term outage of one transformer at a station which would be modeled in the base, followed by event P6 testing on initial system condition of a transformer out of service then followed by a 2nd transformer outage. This would be three transformers out at the same station and this could approach Extreme Events Contingency. R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing, as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment ? Change to read: "For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment" We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MW generator is fairly small in a 30,000 MW system and system concerns would already be addressed through the System Impact Study]?An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1.

Organization	Question 2 Comment
	R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Priority Comment We highly recommend that the standard should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1. Therefore, this requirement should be deleted.
ISO New England, Inc.	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2. R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state (such as a transformer, generator or power electronic device) and not just (such as a transformer). R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately

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	represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2.R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.
Central Maine Power Company	R2 Comment We recommend replacing the phrase prepare with conduct and document in the first sentence. R2.1.1 Comment The requirement to evaluate year one or year two should be removed. This is not consistent with the time horizon identified in R2.

Organization	Question 2 Comment
	R2.1.2 Comment The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. R2.1.3 Comment - The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on reasonable risk. The assessment should have to include a discussion of reasonable risk. The sensitivity list can be used to select sensitivities to assess risk. Having a requirement to perform one sensitivity just to meet the requirement of the standard does not add value to the assessment. R2.1.4 Priority Comment With respect to spare equipment strategy, this requirement imposes severe testing requirements upon the system. However, there is no discussion on the generation dispatch or system transfers that are to be used for this portion of the assessment. The expectations for changes in system stresses need to be clear as part of the standard. Additionally, this section does not contemplate changing the acceptability of load loss. After experiencing a major contingency such as this, some change in the acceptability of load loss should be expected. The standard should consider allowing Non-Consequential load loss for P1 & P2 events. The standard needs to allow Non-Consequential load loss for P3 & P4 events. Why doesn't the standard state "(such as a transformer, generator or power electronic device)" and not just "(such as a transformer)". What constitutes "spare equipment strategy" Would a strategy that involves out-of-merit dispatch or operational restrictions be considered a valid "spare equipment strategy". If a transformer is lost, could a reconfiguration of transmission constitute a valid "spare equipment strategy"? R2.2 Comment We suggest replacing the phrase a current System peak Load study with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment Please provide guidance as to what year should be represented when performing short circuit studies. R2.4.1 Comment Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Comment We suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the present System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. [A 20 MVA generator is fairly small in a 30,000 MW system and system concerns would already be addressed though the System Impact Study]? An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 Priority Comment As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and

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	selected. R2.6 Comment At the end of the second sentence, the phrase in the tables is used. We suggest using more definitive language such as in Table 1?. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date?. R2.6.3 Comment Plans can provide a target in-service year but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year's assessment and develop corrective actions. R2.8 Comment Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. R2.9 Comment This requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment.

Response: The SDT does not think that in Requirement R2 replacing "prepare" with "conduct and document" would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet

Organization	Question 2 Comment

performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, that Load is low, and the generation would have to be turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems as part of the Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The requirement does not preclude a discussion of risk.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective Systems would be more vulnerable to long term outage. In Part 2.1.5 when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2 is intended to require a study performed in the current year, as opposed to studied performed in the past years. Part 2.2 has been revised to provide

Organization	Question 2 Comment

greater clarity.

> **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6:

For Part 2.3 the decision on the year to be represented in the study is left to the discretion of the Planning Coordinator or Transmission Planner. Part 2.3 only requires it to be either study that was performed during the current year or in the past. For example, this year is 2009 and a study performed in 2009 is a current study, the study can investigate the System in a future year, which is at the discretion of the Planning Coordinator or Transmission Planner performing the study. Part 2.3 has been revised to provide greater clarity.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

Part 2.4.1 was not changed as proposed because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of Loads. Note that changes were made to Part 2.4.1 based on other stakeholder comments.

Parts 2.5 .1 and R2.5.2 (new Parts 2.6.1 and R2.6.2) were not combined. The references to the “20 MW” threshold have been deleted from the revised standard.

Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required. The end of the second sentence has been changed to refer to Table 1 as suggested.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Requirement R2, part 2.6.3 has been deleted.

Part 2.6.4 allows the Planning Coordinator or Transmission Planner to address situations that are beyond its control by utilizing Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved. No change made.

Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Organization	Question 2 Comment
Gainesville Regional Utilities	R2.1.1- References a "system peak Load" for each of the referenced years. Some utilities are summer peaking and some are winter peaking and others may have a history of having one or the other in any given year. So can you clarify which peak you are referring to or change to statement to perform studies involving both seasonal peaks? R.2.4.1- I suggest quantifying the reference to the behavior of induction motor loads to single motors greater than 1000 hp or multi motors at one bus totalling more that 2000 hp or so, since smaller induction motors probably will not have any significant impact of the BES. I feel this is best handled as a sensitivity issue determined by the PC who is familiar with this area. R2.5.1- If the system has not had any significant changes of the last ten years, then a study going back to that change should be acceptable for the assessment. R2.5.2- Should the "shall not include" really read as "shall include"? R2.6- The reference to "tables" in line 6 should be "table" since there is only a Table 1 in the standard. R2.6.1-R2.6.3- Question-- Why is the font size of the bullet text smaller that the other bullet segments?

Response: In Requirement R2, part 2.1.1, the selection of the system peak Load conditions is at the discretion of the Planning Coordinator or Transmission Planner. The standard allows for use of past studies to support a current Assessment. Therefore, for an area with both summer and winter peaks, the Planning Coordinator or Transmission Planner can choose to perform summer and winter peak cases on alternate years and the Assessment can rely on, e.g., a summer peak study performed in the current year and a winter peak study performed in the previous year, provided the requirement for use of past year studies is satisfied. No change made.

Part 2.4.1 allows for the use of an aggregate System Load model which represents the overall dynamic behavior of the Load that could impact the study area. So as written, the suggested representation is allowed. Note that changes were made to Part 2.4.1 based on other stakeholder comments.

Part 2.5.1 has been revised and included as Requirement R2, part 2.6.1 to address your concerns.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

In Part 2.5.2 “shall not include” is correct because the intent is that for the past study to be applicable, the present System should not have changed materially compared to that represented in the past study. However, Requirement R2, part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 in the new version to provide greater clarity.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 (now 2.7) was modified to use the phrase, “in Table 1” rather than “in the tables.”

Part 2.5.1 (now 2.6.1) has been revised as shown.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

Organization	Question 2 Comment
2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. For Part 2.6.1 (now 2.7.1) the format has been corrected. Parts 2.6.2 and 2.6.3 were deleted from the revised standard.	
JEA	R2.1.4 It is not clear if this spare equipment strategy excludes Generator Owner's obligations for their generation plant equipment and only includes Transmission Owner's equipment. It is also not clear what Measurable document is required to back up a position of no vulnerabilities. I recommend that we limit the spare equipment strategy to TO equipment and not include GO equipment which excludes step-up transformers, turbines, generators, rotors, etc.Also, it does seem unreasonable to assess the long-term loss of a transformer to the "Extreme Events" of Table 1 or any other event other than the P3 events unless substituted in the assessment by a more extreme and probable event. An event from P3 alone should be sufficient to expose a weakness of a spare equipment strategy based on historical industry statistics for such likelihood. Propose changing "The analysis shall reflect the Contingencies identified in Table 1..." to "An analysis shall be performed that as a minimum assesses the impact of the long term outage of Transmission Owner equipment under either a P3 event that could occur in the absence of the subject equipment" or a more stressful event as deemed appropriate by the Functional Entity performing the assessment. R2.6.4 First of all, some level of expected Non-consequential load loss is always prudent to balance customer expectations on cost and reliability subject to Local and State Authority's guidance. Second, load development and gneration development are the major drivers for transmission development needs. Generation plans are more dependable and manageable as to timing and impact. Load development is not very dependable and manageable relative to transmission system improvement needs. It is not unusual for new load forecast to either expose a transmission weakness or on the other hand to eradicate a transmission weakness in the Near Term horizon. Without guidance, it could be assumed that affects from load forecast are beyond the control of the Transmission Planner and Transmission Coordinator. In addition, it is not unusual to have the load forecast lead the generation plan by a few years causing a need for Non-Consequential Load Loss until such time the additional generation is in-service providing generation balance to the load area and mitigating the transmission improvement needs. This occurs frequently as generation development lags load development in fast growing communities. Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. An additional option for the SDT to consider could be to add an allowance of lag time (maybe 4-5 years) to cover the gap while the generation addition is being developed.
Response: Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. However, the major Equipment is not limited to the major Equipment of the Transmission Owner; this standard covers major pieces of pieces of Transmission Equipment without regard to ownership. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Requirement R2, part 2.1.5 has been revised to require that the analysis reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.	

Organization	Question 2 Comment
2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. For Part 2.6.4 (now 2.7.5), the SDT declines to set a cap on Non-Consequential Load Loss on situations that are outside the control of the Planning Coordinator or the Transmission Planner. The premise is that the Corrective Action Plan has already been developed, but was not able to be implemented in time. The situation can occur with both unexpected changes in generation, Load pattern or delay in permitting and construction of new Transmission Facilities. In addition, a cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made.	
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	Short circuit analysis is a local issue. The reliability of the BES does not depend on the regular assessment of short circuit duty. Therefore, we believe short circuit analysis should be deleted from R2. R2.1.4 needs more clarification as to what constitutes major Transmission equipment. This would require a separate analysis (study) for each transformer (or any long lead-time equipment) for which a spare is not available, which could result in numerous additional cases. Major Transmission equipment could be limited to voltage levels greater than 200 kV. An exception should be made for phase-shifting transformers. As the system changes, with new generation and transmission lines being added, these analyses could become outdated very quickly. If a transformer were to fail, the Planning Department would immediately study the current system with this transformer removed. As stated in R2.4.1, the requirement to include induction motor loads is too prescriptive. At this time, with all of the unknown or estimated variables in the system model, accuracy of the model would not be improved. If a highly industrialized section were to develop within the NWE footprint, induction motor load could be added to the system model. The 20 MW threshold identified as "material change" for generation in R2.5 is too small. A better number for material generation changes would be 100 MW or a limit based on a percentage of the study area's installed generating capacity. Also, an aggregate of 20 MW addition/deletion generation would depend on the location of the individual generators to determine whether the overall system would be affected or not. The statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement. R2.8 should be deleted. It is not necessary for reliability. R2.9 should be deleted. It is not necessary for reliability.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Requirement R2, part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned	

Organization	Question 2 Comment
generation and Transmission Facilities in service which could impact the study area. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.4.1 is intended to allow the Planning Coordinator and Transmission Planner the discretion in the use of Aggregated System Load models in Stability Studies, if specific models are not available. However, it does not dictate the methodology or the process on how the studies are to be done. No change made. Part 2.5 has been revised and included as requirement R2, part 2.6 as shown. Note that the references to the "20 MW" threshold were deleted from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
SMUD	R2.1.3 and R2.4.3The sentence, "sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment: ", should be modified by changing the second 'included' to 'considered'. R2.1.4Since there is no NERC reliability standard requirement for a 'spare equipment strategy', what is the standing of a requirement that is based on having one R2.5.2There is no example given for 'Transmission additions/removals' Recommend that the wording of this requirement be made more discretionary with a requirement that the Transmission Planner include language explaining the reasons for using past studies.
Response: Parts 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised. However, the SDT declines to change the work "included" to "considered" because the intent is that if the base case modeled already models the stressed condition, such as 1 in 10 adverse weather Load, even higher Load may not need to be included in the sensitivity study, **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of	

Organization	Question 2 Comment
	changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. The SDT has included the spare equipment strategy in Part 2.1.4 to ensure that the BES is designed so that it remains reliable even with long lead time Equipment unavailable, consistent with the directive from FERC Order 693. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The SDT revised Part 2.5.2 (now Part 2.6.2) to remove the "Transmission additions/removals" and "generation changes" language.
Progress Energy Florida, Inc.	Concerning R2.1.4, this sub-requirement is overly burdensome for two primary reasons: a) It amounts to a system-wide N-2 and N-3 analysis, which goes against FERC's policy of separation and distinction between types of events as stated in Paragraph 1788 of Order 693: Under TPL-002-0 the system is not required to be able to withstand another N-1 contingency. That N-1 requirement is a Category C contingency which is addressed by TPL-003-0. b) The requirement to perform system-wide analysis for such a scenario is a significant workload issue, and will take time away from analysis of more probable events. Concerning the issue of material changes in past studies in sub-requirement

Organization	Question 2 Comment
	R2.5.2, PEF objects to the specification of changes in units of 20 MW or greater, due to the fact that a change (or even deletion) of a 20 MW unit in a case modeling a large BES does not truly constitute a material change. The SDT in its response to Question 15 in the comments for draft 2 stated that The SDT did not want to be overly prescriptive when describing the type of changes that could be considered material and has left the text general. PEF suggests that the SDT take its own advice, making the language in R2.5.2 more general in nature and leaving such modeling details to the discretion of the Transmission Owner. In R2.6.2, PEF assumes that the term "project initiation date" is intended to mean the Construction Move-In date. If the term means the first date at which Planners had identified it as a mitigation, PEF would object to this as it would appear to preclude the right to develop superior mitigations, or to cancel a project if it can be demonstrated as no longer needed. Concerning R2.8 and R2.9, PEF strenuously objects to such requirements. These requirements have no bearing on demonstrating the reliability (or lack thereof) of the BES, and therefore should be removed from the Standard.

Response: Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the Planning Assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 has been revised and included as Requirement R2, part 2.6.2 to address your concerns. The revised standard does not include the reference to a "20 MW" threshold.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 has been revised and included as Requirement R2, part 2.7 in the new version.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

Organization	Question 2 Comment
2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Xcel Energy	R2.1.3 is this indicating that only one of the variations need to be studied? ("in one or more of the following conditions"). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.3 (now Part 2.1.4) does not preclude the Planning Coordinator or Transmission Planner working with other Functional Entities to develop strategies on performing sensitivity studies. Part 2.1.4 requires that the Planning Coordinator or Transmission Planner perform sensitivity studies for at least one of the variation not already covered in the studies described in Parts 2.1.1 and 2.1.2

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

Organization	Question 2 Comment
rationale for why that year was selected. Part 2.6.4 refers to the situations beyond the control of the Transmission Planner or Planning Coordinator as Functional Entities. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
New Brunswick System Operator	R2.1.4 Major transmission element needs to be defined. For example, what about sync condenser, or generator step up transformer R2.2 Clearity required. Example: What is meant by "current System peak load" It is not clear what supplemental load loss is. Would load tripped due to undervoltage or SPS as a result of a contingency be considered supplemental load? As a follow up what then is Non-consequential load (provide examples). How would this load be lost? The requirements appear the same regardless of the amount of Non-consequential load loss. Is there any consideration of applying thresholds both on suppmental and non-consequential load loss where these loads are defined as (or applied as) "exceeding xxx amount of MW". Regarding Table 1 b, what does the following mean: "However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements." Please clearify the definition of Year One. This definition also does not include Planning coordinator. Was that intentional?
Response: In Part 2.1.4 (now Part 2.1.5), major Transmission Equipment would be those pieces of Equipment, the loss of which can have significant impact on System performance. They are typically the ones listed in the Contingency Events in Table 1. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 refers to a "current System peak Load study". This would be a System peak Load study that is performed in the current year. In the Definition Section, Supplemental Load Loss is defined as Load that is disconnected from the network by end-user Equipment responding to post-Contingency System conditions. Because the disconnection is at the discretion of the Load customer, not the Planning Coordinator or Transmission Planner, they cannot be counted on to leave the System. Therefore, the Transmission System cannot be planned as if such Load would disconnect. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the	

Organization	Question 2 Comment
following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: A cap on the allowable Non-Consequential Load Loss may be different for different areas and may not be practical in a Continent-wide standard. No change made. See response for Part 2.2 above. The definition has been revised to include Planning Coordinator. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.	
Lafayette Utilities System	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full: R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied. In addition to the foregoing, we are concerned that the language of footnote 10 to Table 1 is unclear and subject to at least one interpretation that would seriously undermine reliability. Specifically, the first sentence of footnote 10 permits "[c]urtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch." The reference to an "obligat[ion] to re-dispatch" is ambiguous at best and should be clarified. For example, footnote 10 should not be read as permitting Balancing Authority A to rely on curtailment of firm transmission service coupled with re-dispatch of generation by adjacent Balancing Authority B during a Level 5 TLR event, based on the theory that, if a Level 5 TLR is declared and the Reliability Coordinator assigns to Balancing Authority B an NNL reduction responsibility that compels it to reload its resources, Balancing Authority B is therefore "obligated to re-dispatch" within the meaning of footnote 10. We suspect the intent of the first sentence of footnote 10 was to recognize and give effect to arrangements in which (following the example) Balancing Authority A has made a prior contractual arrangement with

Organization	Question 2 Comment
	Balancing Authority B (or another generation owner) to provide redispatch services when requested by Balancing Authority A. In that circumstance, Balancing Authority A would be allowed to couple the curtailment of firm transmission with redispatch provided by Balancing Authority B (or another generation owner) pursuant to its contractual obligation. We suggest that this limitation be reflected by revising the first sentence of footnote 10 to read as follows: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources subject to a contractual obligation to provide re-dispatch service to the operator of the system for which the Transmission Planner is responsible, is allowed both as a System adjustment (as identified in the column titled "Initial System Conditions") and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Without the limitation reflected in the foregoing revision, an entity could interpret footnote 10 as allowing it to rely on the redispatch of generation by other systems that may be (in effect) mandated by a Reliability Coordinator during a Level 5 TLR event. That sort of "leaning" on adjacent systems should not be permitted as a System adjustment or corrective action under TPL-001, especially where it imposes uncompensated burdens and costs on the system(s) forced to redispatch under these circumstances.

Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.

The SDT has reviewed the application of footnote 10 (now footnote 9) and believes that it is correct. No change made.

Organization	Question 2 Comment
Mississippi Delta Energy Agency	R2.5. This basic requirement intends, as we understand it, to require that earlier studies not be used for a current assessment if they are no longer accurate. But the phrasing is potentially confusing, and would be clearer if revised. Since the requirement deals with the use of past studies, we suggest that R2.5.2 be revised to state that the study may be used only if there have been no material changes, so that R2.5 reads in full:"R2.5. Past studies may be used to support the Planning Assessment if they meet the following requirements: R2.5.1. For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less. R2.5.2. For steady state, short circuit, or Stability analysis: the study may be used only if there have been no 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability of 20 MW or greater. An aggregated

Organization	Question 2 Comment
	addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES which total 20 MW or greater. With respect to footnote 10 to Table 1, we fear that the flexibility suggested by those provisions may be excessive for a planning standard. The ambiguity occasioned by stating emergency actions that can properly be taken in a planning standard can be utilized by those who plan the system in a manner which plans to drop non-consequential loads just as footnote b has been used in the past. If this is intended to raise the bar as stated these provisions do not belong in a planning standard, at least as now stated. It may be appropriate to remove the reference to footnote 10, at least in the Initial System Condition entry in P3, where it suggests that it can be invoked after loss of a single generator, and we request the SDT to review that footnote to assure that it is appropriate in the other entries to which it is applied.
Response: Part 2.5 has been revised and included as Requirement R2, part 2.6 as shown. Note that the revised standard does not include any reference to the "20 MW" threshold. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made**.**	
Ameren	In R2, The phrase document results should be changed to summarize results. While results will be documented, the Planning Assessment should just include a summary. In R2.1, the reference to requirement R2.6 (at the end of the last line) should be changed to R2.5. In R2.1.3, it is suggested that the studies be referred to as the "base studies" to avoid confusion with the sensitivity studies. Also it is suggested that another phrase be added at the end for clarity. The entire R2.1.3 would then be as follows: For each of the base studies described in Requirements R2.1.1 and R2.1.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the studies shall be included in the Assessment. Sensitivity studies would include changes to: In Requirement R2.1.4, it is suggested that language be added to reflect the possible unavailability of the equipment, such as: When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The analysis shall reflect the Contingencies identified in Table 1 during the conditions that

Organization	Question 2 Comment
	the System is expected to experience the possible unavailability of the long lead time equipment. It is not clear how adequate lead times for equipment would be determined. In Requirements R2.3 and R2.4, consider adding a reference to Requirement R2.5 for the past studies. In Requirement R2.4.1, it is suggested that it be reworded to the following: System peak Load for one of the five years, including Load models which appropriately represents the dynamic behavior of Loads, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Load models referenced in R2.4.1 should be confined to the consideration of transient stability study work. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. We suggest adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In Requirement R2.4.3, it is suggested that this sub-requirement be reworded to the following: For each of the base studies described in Requirements R2.4.1 and R2.4.2, sensitivity case(s) that are intended to stress the System with variations in one or more of the following conditions not already included in the base studies shall be included in the Assessment. Sensitivity studies would include changes to: In bullet three of Requirement R2.6.1, would we allow automatic generation tripping for a single (P1) event if it is not consequential? It seems that tripping of generation should be restricted to P2 events 2 or 3 at a minimum. In bullet five of Requirement R2.6.1, is there a maximum duration that operating procedures can be used before a capital project must be included (or completed) in the Corrective Action Plan? In Requirement R2.6.2, it is not clear what constitutes a "project initiation date". Please clarify. Please explain the reason why Requirement R2.8 is needed in the Assessment. Reporting the largest Consequential Load Loss does not impact reliability. Please explain the reason why Requirement R2.9 is needed in the Assessment. Reporting the largest Non-Consequential Load Loss doe not impact reliability. The proposed standard not only raises the bar for system performance requirements, but also raises the bar for reporting and documentation. We need to employ almost as many librarians and technical writers as engineers to develop and keep track of the documentation. Engineers need to spend more time performing the studies and spend less time documenting studies keeping track of documentation for multiple years.

Response: Part 2 has been revised to reflect your suggestion.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Organization	Question 2 Comment

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

The SDT reviewed Part 2.1.3 (now Part 2.1.4) and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.1.1 and 2.1.2" should be sufficient to avoid confusion. No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.3 and 2.4 have been revised to include the reference to the requirements for use of past studies.

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

> **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

Part 2.4.1 has been revised to reflect your suggestion. In addition, Part 2.4 concerns only "The Near-Term Transmission Planning Horizon portion of the Stability analysis". Part 2.4.1 carries the same limitation as Part 2.4.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The requirement has been revised as suggested.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

The SDT reviewed Part 2.4.3 and declined to use the term "base study" because "base study" may have different meanings in different parts of the continent, and the term, "studies described in Parts 2.4.1 and 2.4.2" should be sufficient to avoid confusion. No change made.

Part 2.6 has been revised and included as Requirement, part 2.7 to reflect your suggestion.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

The third bullet in Part 2.6.1 (now 2.7.1) is intended to meet the requirements in Table 1. Generation tripping is allowed at the discretion of the Planning

Organization	Question 2 Comment
Coordinator or Transmission Planner for P1 Events as long as there is no loss of firm Non-Consequential Load. In addition, in the fifth bullet, the duration for use of an operating procedure is also at the discretion of the Planning Coordinator or Transmission Planner because it may not be feasible environmentally to implement Transmission reinforcements in some locations. Project initiation date has been deleted from the requirements. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Puget Sound Energy, Inc.	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. The 20 MW threshold identified as material change for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area's installed generating capacity. R2.7 should be deleted, see comment on R2 above. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event? if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.	

Organization	Question 2 Comment
Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. The language in Part 2.5.2 that referenced a 20 MW threshold was deleted from the revised standard. The SDT assumes that you meant the comment on short circuit analysis above. The SDT declines to delete the requirement as the SDT believes that it is a necessary part of an overall Planning Assessment. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Manitoba Hydro	Requirement Text: R2.1: Reference of past studies should be to R2.5, not R2.6 (typo). R2.1.3: The sensitivity to Planned duration or timing of Transmission Outages should be modified to only include Planned long duration Transmission outages that span multiple seasons, if known. Short duration planned maintenance outages should not be included in a planning assessment. R2.1.4 - The second sentence doesn't read right - the sentence should be changed to read: "The analysis shall reflect the Contingencies identified in Table 1 under the conditions that the System is expected to experience during the unavailability of the long lead time equipment. R2.2.1 - This sub-requirement should be deleted. Why do extra assessments beyond the 10 year period" Any items beyond 10 years will be covered when they fall into the 10 year period. For example, if we assess the 10 year horizon, then the project due to be complete in 12 years will be part of the assessment in 2 years when it is 10 years out. We will have to show every year how our system meets compliance regardless of this extra analysis, so what's the point. Every year we have to show how we comply in the short and long term so what difference does it make when each project is completed as long as we are in compliance or identify Corrective Action Plans (CAPs) along the way. R2.4.1: The statement "a Load model shall be used which appropriately represents the dynamic behavior of Loads is not very crisp. What will appropriate be interpreted to mean by the NERC auditor? Does an MOD standard exist that covers gathering data and validating loads models? This should be a first step. The SDT should add a statement that the application of detailed induction motor modeling can be limited to areas where poor voltage recovery is expected due to a high concentration of such load. The requirement should be modified to require the PC/TP to provide a rationale for the load models used in its specific planning area. R2.5: A Past Study is a definition and should be moved to the definition section. The definition only identifies power changes

Organization	Question 2 Comment
	as possible material changes, but should also include machine control (exciters/governors) changes. We suggest the bulleted list of Material Generation changes be expanded. R2.6.1: Can the SDT clarify how a rate application qualifies as a CAP action? R2.9 - The sentence should refer to maximum Non-Consequential Load Loss not maximum permissible Non-Consequential Load Loss.

Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.3 (now Part 2.1.4), outages that span multiple seasons are included in the last bullet, “Planned duration or timing of Transmission outages”. No change made.

Part 2.1.4 (now Part 2.1.5) has been revised to reflect your suggestion.

> **2.1.5** When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead times longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standards in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been revised to provide greater clarity.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT declines to move past study to the Definition Section because the Definition, once approved, will apply to all NERC Standards, however, past study is only used in this TPL Standard.

In Part 2.6.1, “rate application” refers to rate incentives to change behavior of end-use customers and can be part of the “actions to achieve required System performance”. This is included to allow for non-traditional solutions to achieving required System performance.

Part 2.9 has been deleted.

Organization	Question 2 Comment
E.ON U.S.	R2.1.3Change For each of the studies to For at least one of the studies R2.1.1 and R2.1.2 require that 3 studies be performed each year. As written, the requirement indicates that the transmission planner has to perform at least one sensitivity study for the 3 studies required by R2.1.1 and R2.1.2. This means that the transmission planner would also have to perform 3 or more sensitivity studies each year. One sensitivity study for one of the 3 studies required by R2.1.1 and

Organization	Question 2 Comment
	R2.1.2 should suffice. R2.1.4.Delete "The analysis shall reflect the Contingencies identified in Table 1 during the conditions that the System is expected to experience due to the unavailability of the long lead time equipment. This statement is redundant since R3 requires this analysis for all of R2.1. Including this statement in R2.1.4 and not in R2.1.1 and R2.1.2 makes it appear that this requirement has different performance requirements. R2.4.3R2.4 does not require studies annually. However, if the transmission planner chooses to study a System Peak Load or a System Off-Peak Load condition R2.4.3 requires that the planner also study sensitivity to that same condition in the current year. E.ON U.S. believes it sufficient that the assessment include a sensitivity study for some System Peak Load and some System Off-Peak Load condition.R2.6The third sentence should be modified to include R2.1.4., so that it reads "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3, R2.1.4 and R2.4.3. The annual studies performed for Category P6 alert the Transmission Planner to the risks of transformer failure. The Transmission Planner is required to design the system to limit those risks. If the delivery time for a piece of equipment is 11 months, then P6 allows Interruption of Firm Transmission Service and Non-Consequential Load Loss. If the delivery time for a piece of equipment is 12 months, then P1 requires that the system be designed for no Interruption of Firm Transmission Service and Non-Consequential Load Loss. This is a significant increase in performance requirements for an event that will most likely not extend beyond to a second System Peak Load period. If R2.1.4 is not included in the requirement the transmission planners would essentially be designing for an Extreme Event, i.e., events which are more severe and have a lower probability of occurrence than Planning Events. R2.6.1Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.6.5 Planning Assessments and System Facilities are not NERC defined terms. Operating Procedures, by NERC definition, require significantly more detail than is appropriate for a Corrective Action Plan. It is not appropriate that Transmission Planners write Operating Procedures to be used by NERC Certified System Operators. E.ON U.S. suggests that Operating Procedures be changed to mitigation plans. R2.8There are no requirements to limit Consequential Load Loss. Impacted customers are typically aware of the customary level of service and have chosen not to pay for extraordinary levels of service. E ON US questions the purpose and benefit of this requirement. While continuity of service to end use customers is an important measure of service reliability for which utilities answer to state authorities, BES reliability requires that the system remain balanced and that local failures not result in cascading BES events NERC standards should, pursuant to FPA Section 215, focus solely on BES reliability

Response: Parts 2.1.3 (now Part 2.1.4) and 2.4.3: The SDT disagrees with changing Parts 2.1.4 and 2.4.3 to requiring sensitivity study for only one System condition because this change potentially could reduce the Assessment to be based on one sensitivity study on one System condition. Since the same sensitivity can have different impacts on System performance under different System conditions, and different System conditions may require different sensitivities to be investigated, such limitation may not be adequate to maintain reliability going forward. No change made.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Transmission Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service

Organization	Question 2 Comment
such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreements with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 is not intended for the Planning Coordinator or Transmission Planner to write Operating Procedures, only to reflect the effects or results of the Operating Procedures in its Corrective Action Plan. Mitigation Plan carries a special meaning for Compliance and so may not be appropriate for use in this standard. No change made. The term, "Planning Assessment" is one of several terms proposed for addition to the NERC Glossary of Terms Used in Reliability Standards. "System" and "Facilities" are already approved terms. Part 2.8 is intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the requirement and agrees that as written it was unclear. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
LCRA Transmission Services Corporation	In R2.6.2, it is stated that a project initiation date is required as well as an in-service date. What is considered the project initiation date, the point at which the project plan is approved or the time at which construction is to begin? If it is the time at which construction is to begin, then LCRA TSC believes this requirement does not belong in the TPL-001-1 standard as the construction timeframe for a project is developed by groups outside of Planning based on resources and outage availability.
Response: Project initiation date has been deleted from the requirements.	
National Grid	R2 Comment In the first sentence, replace the phrase prepare with conduct and document and in the second sentence replace "This Planning Assessment shall use current or past studies, document assumptions, document results, and shall cover steady state analyses, short circuit analyses, and Stability analyses" with "The Planning Assessment shall review assumptions of current or past studies and assess the continuing validity of the steady state, short circuit, and stability results. The review of assumptions, supplemental analysis, and updated results shall be documented. R2.1 Comment A. The terms assess and annual study are referenced in the same requirement. It is unclear what constitutes either. Is an annual study required for every area or is an annual assessment required for every area, which may include some supporting study to address changes to the conditions? B. Requirement R2.1 should refer to R2.5 rather than R2.6 R2.1.1 Comment A. Year One and year two do not provide enough time to implement Corrective Action Plans and are better

Organization	Question 2 Comment
	suited for Operations studies. The requirement to evaluate Year One or year two should be removed. B. Is a year 5 study required annually for every area of a system? R2.1.2 Comment ? The requirement should be removed. With no description of the system stresses and generator outages to be applied when assessing the off-peak load, it is difficult to imagine any issues which would arise which are not revealed in the peak load evaluation that could not be addressed through generation dispatch adjustments. Need to define conditions for assessment. R2.1.3 Comment A. The emphasis on sensitivity testing in the existing section appears misdirected and should be focused on the expected accuracy of the assumptions. The assessment should have to include a discussion of accuracy of the assumptions. Having a requirement to perform one more sensitivity not already included is vague and does not add value to the assessment or the standard. B. Planned Transmission Outages are not known in the Planning horizon. Also the release of the outage on any given day is controlled by operations based on the conditions. The conditions are not known for the Planning assessment. The last bullet referring to Planned Transmission Outages should be deleted. C. Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system. D. What is expected from a sensitivity analysis? Is it to change the base case and see how the case responded, is it to create a new base case and rerun all of the events, or is it to change the base case and rerun a select number of events. It is anticipated that the answer will vary based on what is changed. R2.1.4 Priority Comment With respect to spare equipment strategy; this requirement potentially imposes a requirement to plan for three events, which is overly severe. After experiencing a major contingency of a long lead time facility, there should be some change in the acceptability of risk. This change in risk could include an allowance for the loss of non-consequential load or some of the multiple events from Table 1 should be evaluated as Extreme Contingency events. R2.2 Comment We suggest replacing the phrase a current System peak Load study? with a valid System peak Load study in the first sentence. The word current is confusing as some read the word current to mean today's rather than valid. R2.3 Comment A. The requirement to conduct annually isn't consistent with support. We suggest Conducted annually should be replaced with the phrase assessed annually?.B. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption." R2.4.1 Comment A. The two sentences are describing an or condition and they should be merged to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.4.3 Comment - Delete the phrase "are intended to." It is difficult to measure intent and what is important is whether the system has been stressed, not whether the responsible entity intended to stress the system.

Organization	Question 2 Comment
	R2.5 Comment If past studies only support, then a new study is still required. We suggest changing “Past studies may be used to support the Planning Assessment if they meet the following requirements:” to “Past studies may be used to fulfill all or a portion of the Planning Assessment provided they meet the following requirements:” Violation Severity Levels:R2 - There is no VSL associated with R2.5. A VSL should be added, perhaps under Moderate, that "past studies were utilized to fulfill all or a portion of the requirement, but the studies did not meet the requirements in R2.5." R2.5.1 Comment? We suggest deleting this requirement, and incorporating it into R2.5.2.R2.5.2 Comment To incorporate R.2.5.1 into R2.5.2; please modify the section as follows: For steady state, short circuit, or stability analysis the study shall be less than five calendar years old from the date of completion. The present System model 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. A material change does not require the whole study to be redone. It only requires that the affected portion of the study be reassessed. Material generation changes include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. “ An aggregated addition/deletion/change to a group of generating units directly connected to the BES at one point of interconnection through one or more transformers and determined to be material by the Planning Coordinator or Transmission Planner. The reference to the step-up transformer may not capture a wind farm that could have transformers to step-up to a collection voltage and transformer that wouldn’t be labeled a GSU to connect to the system. R2.6 Priority Comment A. As written, this section undermines the value of the sensitivity testing. This section should require a corrective action plan to fix problems determined in sensitivity analysis if there is a reasonable risk of occurrence. We suggest making the standard read Provide documentation that explains the reasoning for the sensitivities considered and selected. B. At the end of the second sentence, the phrase in the tables” is used. We suggest using more definitive language such as in Table 1. R2.6.1 Comment -In the last bullet, the reference to "rate application" is unclear. R2.6.2 Comment The phrase Project Initiation Date needs to be defined. It is unclear if this is the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Comment Plans can provide a target in-service year, but not an actual in-service year. R2.6.4 Priority Comment There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year’s assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient time to incorporate this into that year’s assessment and develop corrective actions. R2.7 Comment A. "Interruption duty" should be changed to "interrupting duty." All terms in the IEEE dictionary related to breaker opening use the word "interrupting," while terms related to loss of supply to customers use the word "interruption."B. The requirement would be clearer if it we restructured as follows: "For short circuit analysis, if the short circuit interrupting duty determined in Requirement R2.3 exceeds the Equipment Rating of fault interrupting devices, the Planning Authority . .

Organization	Question 2 Comment
	." R2.8 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, do we have to prepare one number for P1 and a separate number for P2? The phrase any P1 event and any P2 event in Table 1 could also be read as the worst loading for each event within P1 and P2, which could be hundreds of values depending on how many events are analyzed. We recommend that the requirement be modified to require documentation of the maximum amount of consequential load loss that was relied upon during the assessment of the P1 and P2 events.C. If it is not deleted, "shall provide" should be changed to "shall identify" for consistency with R2.9 R2.9 Comment A. Largest consequential load loss is not factored into the Planning Assessment and should therefore be deleted. B. If it is not deleted, this requirement is unclear. Is this requirement asking for each transmission planner to list their criteria for non-consequential load loss, or is it asking how much non-consequential load loss was being relied upon in the assessment? Including the word “permissible” implies the responsible entity must decide how much Non-Consequential Load Loss is allowed. We recommend that the requirement be modified to require documentation of the maximum amount of non-consequential load loss that was relied upon during the assessment of the P1 and P2 events.

Response: The SDT does not think that in Requirement R2 replacing “prepare” with “conduct and document” would add clarity, since Requirement R2 includes requirement to document assumptions and results. No change made.

In the Definition Section, Planning Assessment is defined as “Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies”. Therefore, in Part 2.1, an Assessment is an evaluation of System performance based on studies performed. While an Assessment is required annually, it can be based on past studies as long as the requirement for a valid past study is met. As such, all studies used to support the Assessment do not have to be preformed annually. No change made.

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1 Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as “The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year”. Operating Studies are performed for system conditions within 12 months of the current calendar year. No change made.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problems that can be addressed if the planned projects proceed as scheduled; (2) A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. No change made.

Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low and the generation would have to be turned off to achieve Load-resource balance. Turning off resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the

Organization	Question 2 Comment

Planning Assessment. No change made.

Part 2.1.3 (now Part 2.1.4) has been rewritten to clarify the intent of the requirement. The Planning Coordinator or Transmission Planner can include a discussion of accuracy of the assumptions in response to the new Part 2.7.2 on the actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.7.2 Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The sensitivity study can cover the "what if" situation where the project start can be delayed or the project may take longer to construct. No change made.

Part 2.1.3 - 'Are intended to' has been deleted.

The SDT declines to make the change as suggested. A Planning Assessment is not the same as a study. As stated in the Definition, a Planning Assessment is a "documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies". As such, a Planning Assessment is based on a number of studies from which to draw conclusions about System performance and to develop Corrective Action Plans where needed. The suggested change would necessarily imply that a study is the same as a Planning Assessment, which is not the intent of Part 2.3.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to address some of your concerns. Part 2.1.4 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or

Organization	Question 2 Comment
	more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2 is intended to require a study performed in the current year, as opposed to studies performed in the past years. Part 2.2 has been revised to provide greater clarity. **2.2** The Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by the following annual current study, supplemented with qualified past studies as indicated in Requirement R2, part 2.6: Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.4.1 was not changed as suggested because the intent of the last sentence is to allow the use of an aggregated System Load model as an appropriate Load representation. The suggested change could be read to mean that an aggregated System Load model would not appropriately represent the dynamic behavior of loads. However, Part 2.4.1 has been revised to provide greater clarity. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.4.3 has been revised to provide greater clarity, and the phrase, “are intended to” is no longer used. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. As revised Part 2.1.3 (now Part 2.1.4) requires the use of sensitivity studies to “demonstrate the impact of changes to the basic assumptions used in the model”. To this end the sensitivity studies need only to be able to demonstrate the impact of changes. Typically, a sensitivity study would be a subset of the study already performed. It usually involves comparing the base cases with and without the change under consideration, and rerunning a list of the worst Contingencies. However, each situation is different and the specifics are left to the Planning Coordinator or Transmission Planner who are more familiar with the situation(s) to be

Organization	Question 2 Comment

investigated.

Part 2.5 (now Part 2.6) was not changed because studies, including past studies, are used to support the annual Assessment, and are not used to support current studies.

The VSL for Part 2.5 (now Part 2.6) was added as a Lower VSL.

R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.

Parts 2.5.1 and 2.5.2 (new Parts 2.6.1 and 2.6.2) were not combined; however, they have been revised to address your concerns.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 has been modified and included as new Part 2.7. The intent is to allow discretion for the Planning Coordinator or Transmission Planner to correct those deficiencies if they are prevalent (i.e., occur is more than one sensitivity). Although not required, the standard does not preclude the Planning Coordinator or Transmission Planner to develop Corrective Action Plans for high risk scenarios. However, if the scenario is high risk, then it should have been included in the base assumptions in the assessment and the Corrective Action Plan would have been required.

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Part 2.6 has been modified and included as new Part 2.7

In Part 2.6.1, “rate application” refers to rate incentives to change behavior of end-use customers and can be part of the “actions to achieve required System performance”. This is included to allow for non-traditional solutions to achieving required System performance.

Part 2.6.3 - Project initiation date and in service date are no longer used in the requirements.

Part 2.6.4 allows the Planning Coordinator or Transmission Planner to utilize Non-Consequential Load Loss and/or curtailment of Firm Transmission Service, which are normally not permitted to address situations that are beyond its control. Depending on the urgency of the need, the Corrective Action Plan may be developed outside the normal Assessment cycle at the discretion of the Planning Coordinator or Transmission Planner involved.

Part 2.7 has been revised and included as Requirement R2, part 2.8 to reflect your suggestion.

2.8 For short circuit analysis, if the short circuit current interrupting duty on circuit breakers determined in Requirement R2, part 2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

Organization	Question 2 Comment
Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed the both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Requirement R2, part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Entergy Services, Inc	The "study area" referred to in R2.3 should be defined. Does it mean external contingency events should be evaluated, or, the effects of internal contingency events on external parties. It should be clarified that generating facilities are not included in R2.1.4. The strategy may include agreements to share spare equipment among facilities, generation owners, and transmission owners. In R2.6.4 what is "prudent"? Who decides what is prudent? Recommend that the word be stricken. R2.6.4 is in conflict with the Implementation Plan. The Implementation plan omits P1 as an event where the bar has been raised but R2.6.4 allows the use of non-consequential load and firm transmission service curtailment. Clearly, the bar has been raised for any event, including P1, which allowed the curtailment of non-consequential load or firm transmission service in the existing standard. In R2.9 is the team requiring that a criteria be set by each Transmission Owner to set a maximum level of non-consequential load loss allowed by that Transmission Owner, or, that the amount of non-consequential load curtailment needed to meet the requirement be documented? What is the rationale for being so prescriptive in requiring specific years to be studied in R2.1.1 Why not allow the TP and/or PC to decide on the three years to be studied in the Near Term?? In the subrequirements of R2.1.3 and R2.4.3, the use of the word timing is unclear. Consider using in service date or “schedule for”. R2.1.4: The spare equipment strategy is too severe. The requirement should take into consideration the probability of occurrence of the events. Losing a transformer followed by the loss of a generator and a second transmission element is very unlikely. Non-consequential load loss should be allowed for this type of analysis. With the elimination of the distinction between system and generating plant stability studies, the blanket requirement in R2.5.1 that all stability analyses be five calendar years old or less, regardless of any material changes to the system, would cause needless work to be performed on those plants or areas of the system where no changes are occurring. Recommend adding the following to the end of R2.5.1: unless justification can be provided to demonstrate that the results of an older study are still valid. In R.2.4.1 it is mentioned that an aggregate System Load model that represents dynamic behavior of the load is acceptable. Does it mean that load at every bus in the study area has to be represented with an aggregate load model? This could be very cumbersome effort and we are not sure whether the software program can handle this magnitude of dynamic data. To help address this, revise Load to be Load that could impact the study area is acceptable. In Requirement R2.6.2, please clarify the definition of "project initiation date". Please explain the reason why Requirement R2.8 is needed in the Assessment and how does reporting the largest

Organization	Question 2 Comment
	Consequential Load Loss impact reliability?? Please explain the reason why Requirement R2.9 is needed in the Assessment and how does reporting the largest Non-Consequential Load Loss impact reliability?? Please clarify the use of the word permissible in the phrase “maximum permissible Non Consequential Load Loss”.

Response: In Part 2.3 because the area that can be impacted is not confined to Facilities ownership, the study area should therefore include all Facilities that can reasonably be impacted. Where the study area involves several owners, coordination is required. However, since short circuit analysis is usually a localized issue, the area impacted would not be extensive.

Part 2.1.4 (now Part 2.1.5) refers to “unavailability of major Transmission equipment” without regard to ownership. Also, Part 2.1.5 only requires a spare equipment strategy but does not dictate the details of that strategy. So sharing of spare equipment is allowed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity’s spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.6.4 has been revised to address your concerns and the word, “prudent” was removed.

The Implementation Plan has been revised to include certain P1 events where the bar is being raised.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled. A Year one or Year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1.

Parts 2.8 and 2.9 were intended to contribute to open and transparent transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

> **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Part 2.1.3 (now Part 2.1.4) and R2.4.3 have been revised to reflect your suggestion.

> **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

Organization	Question 2 Comment
	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. **2.4.3** For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Load level, Load forecast, or dynamic model assumptions. • Expected transfers. • Expected in service dates of new or modified Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to address your concerns. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Part 2.5 has been revised and included as Part 2.6. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.2 was removed.
Great River Energy	R 2.1, 2.3, and 2.4 need consistency. 2.1 says "The Near-Term Transmission Planning portion of the Steady State analysis..." 2.3 says "The short circuit portion of the Planning Assessment ... addressing the Near-Term Planning Horizon..." 2.4 says "The Near-Term Transmission Planning portion of the Stability analysis..." These three sentences confuse the order. As I understand the Planning Assessment has two parts, a Near-Term portion and a Long-Term portion. Each of those parts has three components, a Steady state component, a Short Circuit component, and a Stability component. I

Organization	Question 2 Comment
	believe the standard's language should be structured as such. R2.1.3- The last bullet would seem to indicate that planners have the capability of predicting the future. The statement would seem to fit more in an operating standard. A suggested revision would be: Known long-term transmission outages with duration greater than one year R 2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent to do only a full steady state analysis with regard to long lead time spares? R2.6.2 would seem to be placing the planner again in the capability of predicting the future. Coming up with specific dates based on budgets, projected growth rates, potential permitting issues, and material delivery schedules would make it difficult to define an initiating date and an in-service date. An in-service season and year may be more applicable in a planning study for near-term projects. GRE is not sure why an initiating date is of relevance in an assessment.

Response: In the third posting, the Standard, as proposed, requires steady state, Stability and short circuit analyses for the Near-Term Transmission Planning Horizon; steady state for the Long-Term Transmission Planning Horizon. In the fourth posting, the SDT proposes to add Stability analysis to the Long-Term Transmission Planning Horizon. So the requirements are not the same as you described. However, the Requirements have been revised to provide greater clarity.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part2.6. The following studies are required.

The last Bullet in Part 2.1.3 (now Part 2.1.4) is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. As such the analysis is not limited to steady state studies. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes "timetable for implementation".

Organization	Question 2 Comment
BC Hydro	Comments: Consider changing the second sentence to read, This Planning Assessment shall use current or past studies, document assumptions, document results and shall cover all analyses needed to clearly demonstrate that the proposed system expansion plan meets all planning criteria and standards. This standard should not limit the studies to only steady state analyses, short circuit analyses and Stability analyses none of which seem to be defined anywhere. In some cases it would be appropriate for planning studies to cover analyses of such phenomenon as electromagnetic transients, sub-synchronous resonance, ferroresonance and harmonics. The fact that Stability is capitalized suggests that it refers to the definition of Stability in the NERC glossary, but that definition reads just, The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances?, but stability analyses (often more properly termed dynamic simulation studies) usually encompass more than simply electromechanical or voltage stability. Usually voltage and frequency excursions are also analyzed and perhaps temporary overcurrent also (eg, assessing temporary overvoltage levels across series capacitor banks).
Response: Even though the other types of studies as identified are important for specific cases, a NERC Standard needs to be applicable continent-wide. The modification could require the inclusion of studies such as EMTP, long-term stability, etc., in the annual Planning Assessment, which is not necessary in all cases. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 2:A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission Planning. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) Under R2.1.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. D) Under R2.1.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other?etc). We believe that this language addition improves this requirement. E) Under R2.1.3 there is ambiguity in the seventh bullet language Transmission outages and we believe that this language should read: Planned duration or timing of specifically scheduled or planned for Transmission outages. This language mimics similar language suggested above in R1.1.1 (letter C on page 3 of 9) F) When a spare equipment strategy does not cover the long lead time unavailability as stated in 2.1.4, will the system be treated as “normal system condition and Table 1 requirements or as having a contingency from which system adjustments are to be made prior to subsequent events. We believe that this task will be burdensome for large entities such as RTOs and we are not clear on the benefit that this requirement brings. For example: If in an RTO system where a party has spare equipment, how can the RTO ensure that a spare part from one asset owner can be made available to other asset owners”

Organization	Question 2 Comment
	G) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, find a problem in year ten which has a solution that required twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. H) Under R2.3 the second sentence requires that “The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with any generation and Transmission Facilities in service which could impact the study year”. We suggest changing the language to read: The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System short circuit model with Planned Facilities in service which could impact the study year”. The definition of Planned Facilities was suggested to be added in the comment above in R1.1.2 under letter (E). I) Under R2.4 the second sentence requires states The following studies are required. We suggest changing the language to read: The following current studies are required. We believe that this language addition improves this requirement. J) Under R2.4.1 the first sentence leaves to much ambiguity as to who determines whether severity of system peak or off peak as well as whether the system load levels appropriately represents the dynamic behavior of loads. If the monitoring agency wishes to make this determination than it should be explicitly written here in this requirement. If the assessing entity is to make this determination than we offer the following language suggestion that we feel will improve this requirement. “For one of the five years, the more severe System peak or off peak System load level, as judged by the assessing entity, shall be used which in the judgment of the assessing entity appropriately represents the dynamic behavior of Loads including consideration of the behavior of induction motors”. K) For R2.4.2, we suggest striking this requirement altogether and add System Off-Peak to R2.4.1 above in R2.4.1 under letter (I). L) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Planned Facilities or changes to existing Facilities. M) Under R2.4.3 there is ambiguity in the fourth bullet language capability and we believe that this language should read: Reactive resource capability (Generator, STATCOM, SVC, other etc). We believe that this language addition improves this requirement. N) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System

Organization	Question 2 Comment
	model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: O) Under R2.6.1 the fifth bullet regarding the use of Operating Procedures needs to be made clearer. We believe that the following language will improve this requirement: Use of Operating Procedures specifying how long they will be needed as part of the Corrective Action Plan. Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1. P) Under R2.6.1 the sixth bullet regarding the use of rate applications, DSM, new technologies or other initiatives can be improved with the following language additions: Use of rate applications, DSM, new technologies or other demand side initiatives can be improved with the following language additions. Q) Under R2.6.2 the language regarding project initiation date is vague. We suggest the following definition to be added to this standard and further added to the NERC Glossary of Terms: Project Initiation Date A date in which Planned Facilities are expected to break ground. R) Under R2.8 please add a coma between the words event and caused. A PC/TP would study multiple P1 and P2 events involving consequential load loss not just the largest. Unless the SDT has a measure in mind for consequential load loss, this requirement should be removed. S) Under R2.9 please strike the word permissible and replace with necessary. It is not clear what the SDT is requesting with this requirement.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.

Organization	Question 2 Comment

- **Operations Assessment** — follow-up evaluations and reporting of real time operations

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made

Part 2.1.3 (including the third and seventh bullets) (and now Part 2.1.4) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

Part 2.1.4 (now Part 2.1.5) requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. Perhaps it would help if sharing major Equipment can be part of an operating agreement within entities belonging to the RTO; however, that would be outside the scope of this Standard. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

2.2.1 A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the

Organization	Question 2 Comment

rationale for why that year was selected.

Part 2.3 has been revised to reflect your suggestion.

2.3 The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

In Part 2.4.1, the SDT was not able to locate the reference to the comment on the "ambiguity as to who determines whether severity of system peak or off peak". No change made.

Part 2.4.1 has been revised to provide greater clarity. However, the SDT declines to modify Part 2.4.1 to require study for "the more severe System peak or off peak System load level" for one of the five years in the Near-Term Transmission Planning Horizon because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained.

2.4.1 System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.4.3 (including the third bullet) has been revised to provide greater clarity. The SDT declines to change the fourth bullet because adding a partial list of devices that could provide reactive resources may not improve clarity beyond the present description.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Part 2.5 has been revised and included as Part 2.6.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6.1 has been revised and included as Part 2.7.1 to provide greater clarity. However, the SDT declines to include "Operating Procedures may not include Non-Consequential Load Loss when not permitted in Table 1" because it is redundant. Part 2.6.1 (now Part 2.7.1) is a sub-part of Part 2.6 (now Part 2.7), which

Organization	Question 2 Comment
explicitly requires meeting the performance requirements in Table 1. Parts 2.6.2 and 2.6.3 have been removed since the definition of Corrective Action Plan already includes "timetable for implementation" so a new NERC definition is not required. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
PJM	In R2, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? In R2, I have always heard that dynamics studies are performed to determine Stability. In R2.1, need to update reference to R2.6 from R2.5. In 2.1.1 and R2.1.2, is this annual peak or seasonal peak? Summer peak for summer peaking entities and winter peak for winter peaking entities or both summer and winter peak for all entities. R2.1.1 year one or two studies should be only required as operating studies. By their nature, the upgrades or fixes that could be accomplished in this time frame are limited to short lead time fixes. These analyses are needed to determine how to accommodate construction schedule deviations and near term system issues that may cause issues. Traditional Planning studies will be of no benefit in this timeframe. Change the requirement to be a study for year 3,4 or 5 with updates for material changes that occur when a previous year study is still within this time frame.R2.1.2 and R2.1.1 should be combined and the TP should assess and justify its choice of the critical load scenarios to analyze. Concerned about the extent of variations required in R2.1.3. Like would I have to vary all proposed generator in-service dates? Just a couple? One? Requirements need to be clear or compliance will assume the largest scope possible. Also in R2.1.3, first bullet words should align with the words of R1.1.3. Also in R2.1.3, second bullet words should align with words of R1.1.4 and R1.1.5. Also in R2.1.3, third bullet, modified facilities are not installed, suggest changing -installation to -availability--. Also in R2.1.3, fifth bullet, suggest moving retirements-- up to third bullet and dropping -- Generation additions, retirements, or other-- leaving just dispatch scenarios R2.1.4 should be deleted. There are no NERC requirements on spare equipment availability and this requirement seems like a backhanded way to include such a requirement. R2.2.1 should be reworded because it now requires everyone to extend their studies. Suggest If planned projects will take longer than ten years to complete, the Planning Assessment shall be extended accordingly- R2.4.1 Not sure I understand. The second sentence and the third sentence seem to be in conflict

Organization	Question 2 Comment
	R2.4.2. This requirement has lost significance with the deletion of unit stability. Off-Peak scenarios are critical for unit stability and analysis of pockets of known light load stability sensitivity. This requirement should not be worded to require a general system off-peak stability study since this will not provide useful information. The requirement should be reworded to clarify that the TP should identify its critical off-peak stability sensitivities and provide annual stability analyses that address the system's off peak stability issues.R.2.4.3 should only refer to R2.4.1 since R2.4.2 are sensitivities themselves. In R2.4.3, first bullet, how would load model assumptions be varied? Same comments on bullets here as R2.1.3 above. R2.5.2 is impossible to judge. Material changes needs to be defined. The word could in the sentence before the bullets makes them useless as a definition. By trying to define material changes the SDT has created a situation where, for large interconnection, it would be virtually impossible to use a past study. The addition of a 100 MW generator two states removed from the study area would not be considered material but by the guidelines in this requirement it can be interpreted as such. R2.5.2 Add that retools of past studies that address the local impacts of specific cumulative material changes that occur are sufficient to continue to support current planning assessment. R2.6 has a mixing sigular and plural tenses. What if only one problem is found and therefore only one Corrective Action Plan is needed. Or can one Plan cover all the problems found? Responses to R2.8 and R2.9 would be considered Critical Energy Infrastructure Information (CEII) and that should be noted so it can be protected. R2.8 and 2.9 change to read that the Planning Coordinator will provide its criteria for load loss that is adheared to for all events.

Response: Requirement R2 applies to both the Planning Coordinator and Transmission Planner because the Planning Coordinator may have a larger area than the Transmission Planner. Functional Model Version 3 states that, "Like the Resource Planners and Transmission Planners at the 'local' level, the Planning Coordinator maintains system models and performs the necessary studies to evaluate whether the composite resource and transmission plans of its Resource Planners and Transmission Planners are in compliance with reliability standards". No change made.

Please suggest modifications to more accurately describe "stability" Analyses. No change made.

In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

For Part 2.1.1, Year One and year two are within the Planning Horizon. In the Definition Section, Year One is defined as "The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year". Operating Studies are performed for system conditions within 12 months of the current calendar year. Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A Year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year one or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment and to assess other years in addition to those identified in Part 2.1.1. Part 2.1.2 requires that the Planning Coordinator and/or Transmission Planner also consider off-peak conditions in addition to peak conditions because the System must be able to meet performance requirements over all demand levels. System peak condition may not represent all stressed conditions. For example, during off-peak, the Load is low, and the generation would have to be

Organization	Question 2 Comment

turned off to achieve Load-resource balance. Turning down resources within a Load area could result in reliability problems. Lowering the Load in areas with many non-dispatchable resources could also pose potential problems. As the System incorporates more and more renewable resources, some of them are non-dispatchable; a standard must be forward looking so the Planning Coordinator and Transmission Planner can identify potential problems. If studies for one of the Load periods are not needed annually, the Planning Coordinator or Transmission Planner can rely on past studies for the Planning Assessment.

The bullets under Requirement R1, Part 1.1.3 have been removed from the revised standard, so no effort was made to line up the bullets in Requirement R1, Part 1.1.3 with the first two bullets under Requirement R2, Part 2.1.3. Parts 2.1.3 (now Part 2.1.4) and 2.4.3 and associated bullet lists have been revised to provide greater clarity for the expected changes. "Installation" has been removed from the third bullet. The SDT believes it is appropriate to treat generation change and transmission changes separately and did not move retirements up to the third bullet. The extent of the variations for each item listed is left to the discretion of the Planning Coordinator or Transmission Planner who are more familiar with the system being studied. Load modeling assumptions can be varied by varying, for example, the percentage of motor Load or the customer mix. It is up to the Planning Coordinator or the Transmission Planner to decide how the assumptions would be varied.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.

Part 2.1.4 (now Part 2.1.5) is based on FERC Order 693, Paragraphs 1724 – 1727. Part 2.1.4 requires that the Planning Coordinator and/or Transmission Planner consider the possibility that a piece of major Equipment can be out of service for an extended period of time because no spare piece of Equipment is on hand or

Organization	Question 2 Comment

can be purchased and be placed in service such that the outage won't last into the next planning cycle. Loss of a transformer is given as an example as a piece of major Equipment, which if forced out of service and had to be replaced with a new transformer, may have a lead time of more than one year. However, if a company has a strategy, for example, to have spare transformers in its System, or have agreement with another entity to share spare transformers, it would significantly reduce the probability of an outage of a transformer for longer than one year. The Planning Coordinator and/or Transmission Planner will need to decide which pieces of major Equipment in their respective systems would be more vulnerable to long term outage.

2.1.5 When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised to reflect your suggestion.

2.2.1 A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict.

The SDT declines to include Part 2.4.2 in Part 2.4.3 because it is not intended to be a sensitivity study because the System needs to meet performance requirements under all System conditions including peak and off-peak. In addition, the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason Part 2.4.2 has been retained.

Part 2.5 has been revised and included as Part 2.6 as shown. The language referencing "material generation changes" has been removed from the revised standard.

2.6.1 For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid.

2.6.2 For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.6 has been revised and included as Part 2.7 to address your concerns about mixing singular and plural possibilities. .

2.7 For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The standard does not preclude protection of the Critical Energy Infrastructure Information (CEII). The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2

Organization	Question 2 Comment
events in Table 1.	
Brazos Electric Cooperative	In R2.1, end of paragraph i believe you mean Requirement 2.5, not 2.6. In R2.6.2 we believe maintaining a 'project initiation date' serves no purpose and should be deleted. These dates are wildly variable given the nature of each project and the numerous issues that can affect these dates. 2.6.2 and 2.6.3 should be combined to simply require an in-service year/date and allow the owners to work as needed to meet these dates. We think R2.9 should be deleted as it is vague in nature, seems to serve no purpose and would be hard to verify the accuracy of the value in an audit. 2.8 is direct and can be easily detailed for an audit.
Response: In the new version, Part.2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. Project initiation date and in service date have been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
American Electric Power	AEP agrees with R2.3., but should note that the planning horizon short circuit models are not presently developed in any systematic fashion, since, unlike the development of steady-state (power flow) and stability models that are mandated under MOD-010 and MOD-012, respectively, there are no NERC Standards that mandate the development of short circuit models in a similar fashion. As to R2.4., requiring study of both peak and off-peak conditions in every stability assessment removes the possibility in this regard that stability study scopes may be defined most appropriately by engineering judgment. We believe system load level is often important, but not necessarily more important than any of the other sensitivity variables listed under R2.4.3. We suggest listing system load level along with these and removing R2.4.1. and R2.4.2. The text in R2.4.1., referring to dynamic load modeling, may still be retained somewhere, and since this falls in the category of modeling and data, we suggest including this under R1.1. With regard to R2.5., a 20 MW increase in generation may well be construed as a material generation change, but it is questionable whether a 20 MW decrease would be for transmission planning purposes. Also, the validity of many studies, particularly plant oriented stability studies, may well extend beyond five years if there have been no transmission modifications in the vicinity of the plant or to the plant itself. In these instances, it would seem counter-productive to disqualify a study after five years. The duration of the validity of certain types of past studies is better determined by the occurrence of significant transmission or generation changes. Please note, under R2.6.2., to define project initiation date [Changed sequence to keep in numerical order].

Organization	Question 2 Comment
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt and is not specifically related to new planned Facilities. However, a NERC-wide data base or models similar to MOD-010 or MOD-012 may be neither desirable nor necessary, since short circuit study concerns localized issues and can be contained within a study area. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The SDT declines to include Load levels in sensitivity studies in Part 2.4.3 and remove Parts 2.4.1 and 2.4.2. Since Part 2.4.3 would only require studying one or more of the list of sensitivities, this change can result in no Stability study performed for either peak Load or off-peak Load condition in the Near-Term Transmission Planning Horizon. In addition, the standard does not require a new Stability study be performed annually; the Planning Coordinator or Transmission Planner can rely on past studies as provided in Part 2.5 (Part 2.6 in the new version). For this reason no change was made. Part 2.5 has been revised and included as Part 2.6 as shown. The reference to the “20 MW” threshold has been removed from the revised standard. **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate that the results of an older study are still valid. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
ITC Holdings	Comments: In R2.1, there is a reference to R2. 6. Based on the posted red-line version, we believe this reference should be changed to R2.5. Should this same reference be included in R2.4?? In R2.3, it is stated that the short circuit analysis should be supported by either current or past studies. Should a reference be added to R2.5? In R2.6 it is stated: Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities run in accordance with Requirements R2.1.3 and R2.4.3. While we recognize that this conforms to FERC orders, it would still seem that this statement might be interpreted to mean that CAPs intended to cover a number of sensitivities go beyond standards and be used by interveners to block such CAPs. A revision to the standard to the standard to encourage CAP when needed for numerous sensitivities might be appropriate. R 2.6.4, as written, is very subjective. While we understand the need for R2.6.4, who is the ultimate judge of what situations are beyond the control of the TP or PC responsible for the mitigation plan and if they “are taking prudent actions to resolve the situation” As written, it is the auditor. This will be difficult to prove compliance and might provide significant discrepancies in compliance with standards.

Organization	Question 2 Comment
Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. The reference has been added. **2.4** The Near-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed annually and be supported by current or past studies as indicated in Requirement R2, part 2.6. The following studies are required: Parts 2.3 and 2.4 have been revised to add reference to Part 2.5 (included in the new version as Part 2.6). **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.6 has been revised and included as Part 2.7. A new Part 2.7.2 has been added to require that the Corrective Action Plan include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: **2.7.2** Include actions to resolve performance deficiencies identified in multiple sensitivity studies or provide a rationale for why actions were not necessary. Part 2.6.4 has been revised and included as Part 2.7.5 to address your concerns. The word "prudent" is no longer used. **2.7.5** If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service.	
Northern Indiana Public Service Company	R2.3: Clarify the requirement. Does the short circuit study examine topology for a single year, the topology in years studied using the steady state models or each year of the near term planning horizon?
Response: Part 2.3 requires that the Assessment of short circuit duty requirements are conducted annually addressing the Near-Term Transmission Planning Horizon. However, the specific methodology or assumptions to be used are left to the discretion of the Planning Coordinator or Transmission Planner.	
Minnesota Power	A) Under R2, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R2 only says Long-term Planning. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: Near-Term and Long-Term Transmission

Organization	Question 2 Comment
	Plannin?. B) Under R2.1 there is a reference to qualified past studies in R2.6. We believe that this reference should be pointing to R2.5 not R2.6. C) R2.1.4 addresses the spare equipment strategy. What is the scope of this sensitivity? Is the intent only to do a steady state analysis on equipment with long lead time spares D) Under R2.2 a System peak load study is required annually for one of the years in the assessment period. R2.2.1 requires the assessing entity to extend their planning assessment to accommodate any known longer lead time projects that may take longer than ten years to complete. It does not make sense to study the ten year horizon, then find a problem in year ten which has a solution that requires twelve years to build. For compliance with this standard, you would need to find another solution that can be built within ten years as opposed to the suggested language in R2.2.1 of extending the planning assessment beyond ten years to accommodate the solution that falls outside of the Long-Term Planning Horizon. No project solution greater than 10 years should be acceptable because it falls outside the Long-Term Transmission Planning Horizon. Suggestion to strike sub-requirement R2.2.1 from this standard. E) Requirements R2.1, R2.3, and R2.4 are written inconsistently. 2.1 says The Near-Term Transmission Planning portion of the Steady State analysis 2.3 says The short circuit portion of the Planning Assessment addressing the Near-Term Planning Horizon 2.4 says The Near-Term Transmission Planning portion of the Stability Analysis These three sentences confuse the order. As we understand, the Planning assessment has two parts: a Near-Term portion and a Long-Term portion. Each of those parts has three components: a Steady State component, a Short Circuit component, and a Stability component. We suggest the language in the standard should be structured consistently and appropriately as such) Under R2.4.3 there is ambiguity in the third bullet language new or modified Facilities and we believe that this language should mimic that of R1.1.2 in order to improve this requirement. The third bullet should read: Timing of the installation of new Facilities or changes to existing Facilities. G) The sub requirement R2.5.2 states that for steady state, short circuit, or stability analysis; the present System model shall not include any material changes, such as..etc. The present language in this section is vague and requires discretion on the part of both the Transmission Planner and the Planning Coordinator performing the assessment. For example, new transmission enhancements may have been added since the previous System model was developed. In general, such topology enhancements will only improve reliability and would not necessitate re-assessment with a newly updated System model. In addition, any significant generator additions would have been evaluated with a full separate generator interconnection study at which the full reliability of the System would have been taken into consideration. For this reason, we believe the following language for R2.5.2 would improve this requirement: For steady state, short circuit, or Stability analysis: the current System model of the assessed plan year shall not include any changes material to the assessment, as judged by the entity performing the assessment, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study year. Material generation changes could include: H) Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability In addition, it is not clear whether initiation refers to

Organization	Question 2 Comment
	the commencement of engineering, design, construction, etc.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations

In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. It is not intended to limit to steady state analyses only. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

As written the Planning Assessment consists of 2 parts: Near-Term Transmission Planning Horizon and Long-Term Transmission Planning Horizon, Steady State and Stability Assessments are required for both near-term and long-Term, but short circuit assessment is required only for the near-term. Part 2.3 has been revised

Organization	Question 2 Comment
to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. The 3rd bullet of Part 2.4.3 has been revised. **2.4.3 bullet 3** Expected in service dates of new or modified Facilities Part 2.5.2 has been revised and included as Part 2.6.2 to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
LADWP	R2.3 There is no value to conduct short circuit analysis on an annual basis. Short circuit contribution is location constrained. Maximum short circuit interrupting duty cannot be determined by any planning cases; so putting this requirement in TPL will cause only confusion and will creat misleading information. If there is a need to develop a standard on how to evaluate maximum short circuit interrupting duty, the more appropriate place would be FAC. R2.1.3 Controllable Loads and DWM: DSM should not be a stand alone item in planning studies because DSM already is imbedded in load forecasts. Not sure what controllable loads are. R2.1.4 Any requirment dealing with spare parts should be handled in TOP, not TPL. TOP is the forum to develop operating procedures,"work-arounds", and so on when the non-availability of spare forced a company to develop temporary mitigations and it would be a mistake to suggest that planners should be able to consider such temporary fixes as acceptable planning solutions.R 2.5.2 The 20 MW threshold, at best, is "noise" for us. We would not be concerned with generation chnages that is 10 times this threshold. What is the rationale for requiring a new study just because there is a change in generation capability? R2.8 and 2.9 What measurements would this required information be measured against? I can't find any and if there is no measurement, it really does not belong. R2.6.2 Project initiation date is hard to define. Is it the date the project is budgeted? or the date the management approved the budget and at what level? or is it the date when engineering design is initiated? For both short term and long term planning horizons, the project in service date should be sufficient. there are too many variables to define "project initiation date" not to mention there is no measurable to benchmark such a requirement.
Response: Parts 2.3 and 2.7 are intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have the interrupting capability for Faults that they will be expected to interrupt. No change made. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies, for example, if DSM is imbedded in the Load forecast, the sensitivity study can simulate	

Organization	Question 2 Comment
conditions where not all effects of DSM is realizable, and the Load may be higher than studied . Controllable Load can be part of the local rate incentive program, where the customer Load can be controlled by the Transmission Operator. The bullets are examples, so the Planning Coordinator or Transmission Planner can choose the sensitivity and does not have to study, for example, controllable Load, if the related Load-Serving Entity does not have such a program. Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Parts .2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. Part 2.5.2 (now 2.6.2) has been revised for clarity and the 20 MW threshold has been removed. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Project initiation date has been removed from the requirements.	
Platte River Power Authority	R2.6.2. Expand on the meaning of the "initiation date." R2.8. I don't understand the relevance of this requirement. May your intention be explained differently? R2.9. I don't understand the relevance of this requirement. May your intention be explained differently?
Response: Project initiation date has been removed from the requirements. Parts 2.8 and R2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
MAPPCOR	R2.1.1 Consider calling this Near Term years instead of specifically naming certain years.

Organization	Question 2 Comment
	R2.1.3 eliminate the last bullet. Planned duration or timing of Transmission outages is part of R1.1.1 which already specifies that models will include planned outages of generation and transmission facilities. R2.1.4 the second line is unclear. There is a reference to lead time of one year or more Is the intent for that to mean outage duration of one year or more??? If so, it should be written that way. Also, in the 3rd line, eliminate the words an analysis of (otherwise it would direct one to assess an analysis.) This in essence is an N-3 study. This risk that a TO or GO takes will show up in the operations of the BES. Also some states assess a penalty for equipment that is sitting idle that cost the taxpayers, so you could be penalize for not have spare equipment or if you do have it. R2.2.1 does this mean, for example, that entities may be doing 12 year or 15 year assessments? It should be written to say what it means. R2.4.1 Change to read: For peak System Load levels, a Load model shall be used which appropriately represents the dynamic behavior of Loads, including consideration of the behavior of induction motor Loads or an aggregate System Load model which represents the overall dynamic behavior of the Load. R2.5.1 Suggest deleting this requirement, and incorporating it into R2.5.2. R2.5.2 Incorporate R.2.5.1 into R2.5.2; please modify the section as follows:For steady state, short circuit, or Stability analysis the study shall be less than five calendar years old or less: the latest Transmission Planning Horizon System model 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. Material generation changes could include: The addition/deletion/change of individual generating unit capability determined to be material by the Planning Coordinator or Transmission Planner. An aggregated addition/deletion/change to a group of generating units directly connected through their step-up transformer(s) to the BES determined to be material by the Planning Coordinator or Transmission Planner. R2.6 ? The creation of hard and fast Corrective Action Plans for the LTRA is not a good use of resources. The reason for planning studies is to uncover possible weak spots in the system for some number of years into the future, and then pursue additional studies to examine the issues. Planning studies include many assumptions, and the issues may not even arise on the real system. If they do, there may be many possible remedies. Creating CAPs with milestones and other firm dates for potential problems uncovered in assessments of future years is simply not practical, and the PC (PA) may have little or no influence on what remedy is selected even if a problem appears to be real. R2.6.2 The phrase Project Initiation Date needs to be defined. It is unclear if this is this the date of ground breaking, purchase orders being issued, solution study initiation, etc. Additionally, in the second sentence the phrase as well as an in-service date should be modified to read as well as a target in-service date. R2.6.3 Plans can provide a target in-service year but not an actual in-service year. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). There should be a cutoff point when changes occur beyond a certain date. When that date occurs, further changes will be evaluated in the next year's assessment. Otherwise, if a state makes a decision not to site a project a few weeks prior to the end of the assessment period, there will not be sufficient

Organization	Question 2 Comment
	time to incorporate this into that year's assessment and develop corrective actions. R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?

Response: Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the Near-Term Transmission Planning Horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in R2.1.1.

The last Bullet in Part 2.1.3 is intended to cover planned outages of Facilities in sensitivity studies if such planned outages are known at the time the planning studies are performed, for example, a planned outage of a major Transmission line during construction if the Corrective Action Plan calls for rebuilding of the line to a higher operating voltage. The corresponding sensitivity could simulate unplanned delay starts or unplanned extension of construction period of the planned project. No change made.

Part 2.1.4 (now Part 2.1.5) is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Transmission equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed**.** Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line.

> **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.

Part 2.4.1 has been modified.

> **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

Part 2.5.1 (now Part 2.6.1) is considered a separate requirement by the SDT and has not been deleted or merged. It has been revised for clarity.

> **2.6.1** For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided

Organization	Question 2 Comment
to demonstrate that the results of an older study are still valid. Part 2.5.2 (now Part 2.6.2) has been revised for clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6 has been revised and included as Part 2.7 to address your concerns. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: Project initiation date has been deleted from the requirements. The requirement for in service date has been deleted. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in he new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Orlando Utilities Commission	-I think R2.1 has a typo and should reference requirement R2.5, not R2.6. – R2 Does the phrase “System Peak Load” require true system peak be tested, or a peak condition. As an example, FRCC experience a two peak loads, a summer peak that occurs regularl
Response: In the new version, Part 2.6 now contains the requirement for the use of past studies, so Part 2.1 now has the correct reference. No change made. System peak Load means the highest Load within the time period that is being evaluated.	
American Transmission Company	We propose the following comments for R2:In sections R2.1.3 and R2.4.3 please explain the reference to expected transfers and how that differs from R1.1.5 interchange. If these are analogous, then change the references to interchange. Modify R2.5.2 second bullet to clarify that this addresses an aggregated addition/deletion/change to a group of generating units directly connected through a shared step-up transformer . . . . Modify R2.6.2 to remove the obligation to include the project initiation date. The inclusion of this date would add unnecessary work that is not needed to assure adequate BES reliability. In addition, it is not clear whether initiation refers to the commencement of engineering, design, construction, etc.ATC agrees that the Transmission Planner should be responsible for a corrective action plan (R 2.6) and its associated sub-requirements, but we do not agree that the Planning

Organization	Question 2 Comment
	Coordinator should also be listed. Unlike a Transmission Planner, a Planning Coordinator does not have the ability or responsibility to implement a corrective action plan. Requirement 2.6 and its associated sub-requirements should be limited to only the Transmission Planner. Remove the R2.8 requirement. The activity of identifying and including the largest Consequential Load Loss caused by any P1 or any P2 events in the Planning Assessment may not assure adequate BES reliability. A P1 or P2 event with the largest Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The amount of Consequential Load Loss may not have a relevant correlation to system performance and reliability. Remove the R2.9 requirement. The activity of identifying and including the maximum permissible Non-Consequential Load Loss caused by selected Table 1 Planning Events may not assure adequate BES reliability. The maximum permissible Non-Consequential Load Loss could occur at a location on the system that is strong enough to not result in any performance violation. The maximum amount of Non-Consequential Load Loss may not have a relevant correlation to system performance and reliability. Add R2.10. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than performance note a in the Planning Events, Steady State Only section of Table 1. And the obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather than performance note b in the Planning Events, Stability Only section of Table 1. In addition, due to the system limit requirements of FAC-010 and FAC-014 the reference to the PC and TP is unnecessary. We suggest this text: The Planning Assessment shall identify the applicable steady state voltage, post-Contingency voltage deviations, and transient voltage response limits.

Response: Part 1.1.5 has been revised to state "Known commitments for Firm Transmission Service and Interchange" The NERC Glossary of Terms defines Firm Transmission Service as "the highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption" and Interchange as "Energy transfers that cross Balancing Authority boundaries. "Transfer" can cover more than Firm Transmission Service or Interchange. Parts 2.1.3 and 2.4.3 would cover the sensitivity of changes in expected transfers regardless of the cause.

Part 2.5.2 – The examples in the bullets have been deleted.

Part 2.6.2 - Project initiation date has been deleted from the requirements.

Part 2.6 has been revised and included as Part 2.7 in the new version to address your concerns. The SDT declines to limit the application of Part 2.6 to the Transmission Planner because the Planning Coordinator would be responsible for coordination between Transmission Providers.

> **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall:

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new

Organization	Question 2 Comment
version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1. The obligation to identify potential steady state, transient, post-transient and post-Contingency problems is already included in Parts 2.1 through 2.4 and in Part 2.6 (Part 2.7 in the new version). Therefore adding a new Part 2.10 is not needed.	
Turlock Irrigation District	TID expresses concern that the planning extension of R2.2.1 could lead to a scenario where a single members long term project (beyond 10 years) could then require all neighboring members to extend their own planning horizons (similar to a lowest common denominator issue) and face unnecessary technical issues.
Response: Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. If a neighboring Planning Coordinator or Transmission Planner extends their planning horizon beyond ten years, it may be prudent for the Planning Coordinator or Transmission Planner to similarly extend the associated planning horizon, but it is not necessary for compliance of this standard. Therefore, the Planning Coordinator or Transmission Planner can choose whether to extend the planning horizon beyond 10 years for its own planning area(s) for the purpose of compliance. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected.	
New York Independent System Operator	R2.1.2 - System off-peak is more likely a stability issue than a steady state issue. If system off-peak becomes a steady state issue, it can be mitigated through generation redispatch. Accordingly, it appears that this requirement is not necessary for steady state analysis R2.1.4 - With respect to spare equipment strategy, this requirement potentially imposes a requirement to plan for three events, which is overly severe. As previously stated in R1, the system model should be a model of the projected system, which would include a long term actual forced outage. If this requirement is not referring to actual outages, then it is suggesting an N-1-1-1 analysis, which is a requirement that would require significant additional work with little value added for reliability because such contingencies have a very low probability. Under R2.5 - Past Studies may be used to support the Planning Assessment if they meet the following requirements and the sub-requirement R2.5.2 states that for SS, SC, or stability analysis “the PRESENT (emphasis added) System model shall not include any material changes, such as, . The NYISO interprets this language to mean that past studies may be used to support planning assessments as long as there are no material changes to the LATEST PLANNING HORIZON system model. The Standards Drafting Team should clarify whether this interpretation is correct. The standard should further state whether, if there was a material change such as a 20 MW generator, the past study may be used if the impact of this small change is assessed. Finally, the regional entity should have a process to determine whether changes are material that is

Organization	Question 2 Comment
	similar to the NPCCs process for determining what level of annual transmission review should be conducted each year.

Response: Regarding comment on Part 2.1.2, NERC Standards require that Systems can operate reliably over all demand levels. If steady state problems under off-peak conditions needed to be corrected through re-dispatch and/or switching to reconfigure the System, then a Corrective Action Plan involving re-dispatch and switching will need to be developed to ensure that the plan can be implemented. Since a past study can be used to support a current Assessment in accordance with Part 2.5 (Part 2.6 in the new version), an off-peak study would not have to be performed every year.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.5.2 (now 2.6.2) has been revised for clarity. The bullets under 2.5.2 have been removed from the revised standard.

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Organization	Question 2 Comment
Duke Energy	R2 Instead of document results the requirement should be to summarize results. While results will be documented, the Planning Assessment should just include a summary. R2.1 What's the value in being able to use qualified past studies if you have to use annual current studies? Strike the words supplemented with and insert the word or. R2.5.2 Suggest deleting the phrase Material generation changes could include: and the two accompanying bullets. A change of 20 MW on a large system may not always be material. R2.8 and R2.9 should be deleted. We don't see a reliability-related need for these requirements. In the sub-requirements of 2.1.3 and 2.4.3, the use of the word timing is unclear. Consider using in service date or schedule for. R2.4.1: It is not clear how much Load a dynamic model must have. Likely, it must still be proven that the analysis software can accommodate every load in the model having a load model that includes induction motor models. To help address this, revise Load to be Load that could impact the study area is acceptable.

Response: Requirement R2 has been revised to provide greater clarity and the word, "summarize" was added in support of your suggestion.

Organization	Question 2 Comment

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

In Part 2.1 it is envisioned that not all parts of the studies, on which the Assessment is to be based, can rely on past studies. For example, a study on year five performed during the past year may not be representative of year five in the current year. A past study can still be used if it can be demonstrated that the requirements for use of past studies are met. No change made.

2.5.2 – Both bullets under 2.5.2 have been deleted as suggested

Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees with the majority of the commenters that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only.

2.9 The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.

Parts 2.1.3 (now Part 2.1.4) and 2.4.3 have been revised.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Real and reactive forecasted Load.
- Expected transfers.
- Expected in service dates of new or modified Transmission Facilities.
- Reactive resource capability.
- Generation additions, retirements, or other dispatch scenarios.
- Controllable Loads and Demand Side Management.
- Duration or timing of planned Transmission outages.

2.4.3 For each of the studies described in Requirement R2, parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

- Load level, Load forecast, or dynamic model assumptions.
- Expected transfers.
- Expected in service dates of new or modified Facilities.

Organization	Question 2 Comment
• Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. Part 2.4.1 has been revised to reflect your suggestion. **2.4.1** System peak Load for one of the five years. System peak Load levels shall include a Load model which represents the dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.	
Tucson Electric Power Company	Short circuit analyses is a local phenomenon and should not be required as part of a transmission planning assessment of the BES. In any case, the effects of failure of over-stressed breakers are already included in the Events to be assessed in Table 1. For example, P2-3 and P2-4 (Internal Breaker Fault), and P4 (Stuck Breaker while attempting to clear a fault). In R2.1, we believe the reference for past studies should be Requirement R2.5 not Requirement R2.6. Also, we suggest removing the phrase supplemented with and replacing it with the word or. This phrase indicates that previous studies cannot be a primary source for the assessment, which contradicts section 2.5.Remove the phrase not already included in the studies in R2.1.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. Clarity is needed in R2.1.4. The requirement to assess the Contingencies identified in Table 1 is too burdensome. This requirement does not specify any limits on the equipment for which an analysis must be conducted. As currently drafted, this could require a separate analysis for each transformer (or any long lead-time equipment) for which a spare is not available. A separate initial case would need to be developed to assess the Contingencies identified in Table 1 for each transformer. This could result in a countless number of additional cases. We recommend a threshold be established, such as all transformers with a low side voltage above 200 kV. We also recommend changing this from a separate sub-Requirement to one of the sensitivities to be considered under 2.1.3. We also believe that the statement at the end of R2.6 that indicates corrective action plans are not required solely to meet the performance requirements for sensitivities should also apply to the spare equipment requirement.Remove the phrase “not already included in the studies” in R2.4.3. With this phrase included, you cannot use a previous sensitivity study to support the current assessment and Requirement R2.5 allows the use of previous studies if the conditions are met. The 20 MW threshold identified as “material change” for generation in R2.5 is too small. The limit should be raised or based on a percentage of the study area’sinstalled generating capacity. R2.8 should be deleted. It is not necessary for reliability. What will be done with this information on the “largest Consequential Load Loss and the associated event caused by any P1 event and any P2 event” if it is documented? R2.9 should be deleted. It is not necessary for reliability. It will be difficult to determine the maximum permissible Non-Consequential Load value. It will end up being based on cost (monetary, societal, environmental, etc.), which is dependent, among other things, on the types of load being served. It very well may be a case by case situation.
Response: Part 2.3 is intended for the Planning Coordinator and/or Transmission Planner to assess the whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability is localized and may be related to new	

Organization	Question 2 Comment
planned Facilities, it is important to BES reliability. Part 2.3 has been revised to provide greater clarity. **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area. Part 2.1 requires certain current studies be conducted each year for the Near-Term steady state assessment, which can be supplemented with past studies. The SDT disagrees that the statements are contradictory. No change made. Part 2.1.4 (now Part 2.1.5) has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.6 (now Part 2.7) has been revised for clarity. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The material change wording has been deleted from the requirement. . Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
Independent Electricity System Operator	1. We think "conduct and document" is more appropriate than "prepare". Suggest to make this change. 2. We understand the reason for introducing the spare equipment strategy in R2.1.4 is to address comments raised on planned and long-term outages. However, this is not the only cause of unavailability of major Transmission equipment for more than 12 months. Construction or line upgrade program may also require certain transmission facilities be taken out of service for a protracted period. We suggest that R2.1.4 be revised to "When an entity's spare equipment strategy or transmission project construction plan could result in the unavailability of".. 3. When would PCs and TPs be expected to perform the analysis referred to in R2.1.4 ? in anticipation of the possibility of unavailability of major transmission equipment of after such unavailability has occurred or is planned?

Organization	Question 2 Comment
	4. R2.3: The first sentence is unclear and the wording can be supported is misleading. We suggest the first sentence be revised to: The short circuit analysis portion of the Planning Assessment addressing the Near-Term Transmission Planning Horizon shall be conducted annually and be supported by current or past studies. Alternatively, language similar to R2.4 may be considered: "The Near-Term Transmission Planning Horizon portion of the short circuit analysis shall be assessed annually and be supported by current or past studies. 5. R2.4 stipulates the details of the study for Near-Term Transmission Planning horizon for the stability analysis. Unlike its steady state analysis counterpart, there is no requirement stipulated for the Long-Term Transmission Planning horizon for the stability analysis. Is this intentional, or do the same conditions apply to the Long-Term stability analysis" 6. R2.6: Suggest to change in the tables to Table 1 at the end of the second sentence. 7. We agree with the VRFs, Mitigation Horizons and Measures. We also agree with the VSLs except R2.5 is not included. However, If R2.5 is meant to be explanatory (to illustrate the conditions under which past studies may be used), then the conditions should be provided in those requirements (e.g. R2.3) that allow for the use of past studies. If, however, these conditions are meant to be requirements, then their VSLs should be developed.

Response: The SDT does not see the proposed language as an improvement. No change made.

In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment.

> **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment.

Part 2.3 has been revised to provide greater clarity**.**

> **2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to determine whether circuit breakers have interrupting capability for Faults that they will be expected to interrupt using the System short circuit model with any planned generation and Transmission Facilities in service which could impact the study area.

The SDT added Part 2.5 to address your concern.

> **2.5** The Long-Term Transmission Planning Horizon portion of the Stability analysis shall be assessed to address the impact of proposed generation additions or changes in that timeframe and be supported by current or past studies.

Organization	Question 2 Comment
Part 2.6 (now Part 2.7) has been changed as suggested. **2.7** For planning events shown in Table 1, when the analysis indicates an inability of the System to meet the performance requirements in Table 1, the Planning Assessment shall include Corrective Action Plan(s) addressing how the performance requirements will be met. Revisions to the Corrective Action Plan(s) are allowed in subsequent Planning Assessments but the planned System shall continue to meet the performance requirements in Table 1. Corrective Action Plan(s) do not need to be developed solely to meet the performance requirements for a single sensitivity run in accordance with Requirements R2, parts 2.1.4 and 2.4.3. The Corrective Action Plan(s) shall: The Lower VSL has been revised accordingly. R2, Lower VSL: The responsible entity failed to comply with Requirement R2, part 2.9 or Requirement R2, part 2.6.	
Kansas City Power & Light	R2.1.3 is this indicating that only one of the variations need to be studied? (in one or more of the following conditions). Recommend having the planner work with the load to determine what sensitivity studies to perform. R2.1.4 it is unclear as to what should be done with the analysis that incorporates the company's spare equipment strategy. Is this requirement inferring that a company's spare equipment strategy need to ensure that it can still operate to within the requirements for contingencies of Table 1 without the component? R2.2.1 ? is the intent to have the study for the 10 year horizon or to include any project that is started within the next 10 years and thus the study must be extended to the forecasted completion of the project (conceivably as long as 20 years or more?) R2.5.2 - Remove the word intervening and this requirement must be more specific about what this requirement is trying to communicate and acccomplish. R2.6.4 recommend clarifying how situations beyond the control of the TP or PC are determined. It is unclear if this is to imply that if something is outside of the control of the department who conducts the planning studies or if it is outside the control of the registered function's legal entity (i.e. corporation). R2.8 appears to be nonessential information for reliability; for what purpose does this requirement exist? R2.9 - appears to be nonessential information for reliability; for what purpose does this requirement exist?
Response: Part 2.1.3 (now Part 2.1.4) is intended for the Planning Coordinator or the Transmission Planner to investigate at least one of the conditions listed. Part 2.1.3 has been revised to provide greater clarity. It is expected that there will be coordination between the Planning Coordinator, the Transmission Planner and the other impacted Functional Entities. **2.1.4** For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance. • Real and reactive forecasted Load.	

Organization	Question 2 Comment
	• Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages. In Part 2.1.4 (now Part 2.1.5) when a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will apply. Part 2.1.5 is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare Equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of equipment will be replaced. If not, its impact of unavailability would need to be assessed. Part 2.1.5 has been revised to require that the assessment reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time Equipment. **2.1.5** When an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that has a lead time of one year or more (such as a transformer), an analysis of the impact of this possible unavailability on System performance shall be assessed. The Planning Assessment shall reflect the P0, P1, and P2 categories identified in Table 1 during the conditions that the System is expected to experience due to the possible unavailability of the long lead time equipment. Part 2.2.1 has been revised because extending the Planning Horizon beyond 10 years for projects with lead time longer than 10 years is already covered in the definition of Long-Term Transmission Planning Horizon. This allowance is needed to provide planning flexibility, and is at the discretion of the Planning Coordinator or Transmission Planner. For example, if the System is found not to meet performance standard in year 10, but the project to correct the loading cannot be placed in service for 12 years, then the Corrective Action Plan needs to identify the interim solutions before the project can be brought on line. **2.2.1** A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity. **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area. Part 2.6.4 (now 2.7.5) does not prejudge the acceptability of the situation outside the control of the Planning Coordinator or Transmission Planner, which has prevented the implementation of the Corrective Action Plan, provided that the Planning Coordinator or Transmission Planner documents that they are taking actions to resolve the situation. The Transmission Planner or Planning Coordinator shall document the situation causing the problem, alternatives evaluated, and the use of Non-Consequential Load Loss or curtailment of Firm Transmission Service. Parts 2.8 and 2.9 were intended to contribute to open and transparent Transmission planning for peer review. The SDT reviewed both requirements and agrees that as written, they were unclear. Part 2.9 has been deleted. Part 2.8 has been revised and included as Part 2.9 in the new version to require that the Planning

Organization	Question 2 Comment
Assessment provides the expected largest Consequential Load Loss identified by the analysis of P1 and P2 events in Table 1 only. **2.9** The Planning Assessment shall provide the expected largest Consequential Load Loss (megawatt Demand) identified by the analysis of P1 and P2 events in Table 1.	
ReliabilityFirst Corporation	R2- Suggest changing annual Planning Assessment to "annual Planning Assessment Report". Requires short circuit analysis, at present NERC wide common data base for conducting short circuit analysis, does not exist. Short circuit analysis is only performed when there are major system changes and their impact is local. R2.1.1 requires either Year One or year two, and year five. NERC members utilize Models developed by MMWG for the assessment study needs and they are usually lag by one year. R2.1.3 -Suggest changing last bullet to read "Transmission lines, Transformers, Generating unit and Reactive sources that are scheduled for extended outages during the study period should not be included in the Assessment Model." R2.4.1- The requirements in the two sentences seem to contradict each other. R2.4.2 – This does not mention modeling dynamic behavior of loads. R2.5.2 – "could include" is weak and may not be enforceable. Suggest removing all the text after the first paragraph. Does this require any additional studies to demonstrate that the changes do not impact previous conclusions? R2.7 – Short Circuit analysis should not be a part of Performance Requirements". These should be included in "PRC" Standards

Response: Requirement R2 has been revised.

R2. Each Transmission Planner and Planning Coordinator shall prepare an annual Planning Assessment of its portion of the BES. This Planning Assessment shall use current or past studies, document assumptions, summarize documented results, and cover steady state analyses, short circuit analyses, and Stability analyses.

Part 2.1.1 is intended to require studies for System Peak Load Conditions for 2 of the years in the near-term planning horizon: (1) A year five case to identify potential problem that can be addressed if the planned projects proceed as scheduled; (2) A Year One or year two case to identify any potential problems unanticipated in the five-year case, which if not addressed, could impact operations as time progresses. The standard provides flexibility for the Planning Coordinator or Transmission Planner to use past studies to support the current year assessment, and to assess other years in addition to those identified in Part 2.1.1. Therefore, if the models developed by MMWG lag by one year, it can qualify as a valid past study.

Planned outages of generation and Transmission Facilities are included in Part 1.1.1 (included as Part 1.1.2 in the new version). Transmission Facilities covers lines, reactive devices, and other substation equipment. Part 2.1.3 (now Part 2.1.4) is intended to cover sensitivity studies on "what if" scenarios. Part 2.1.4 has been revised to provide greater clarity.

2.1.4 For each of the studies described in Requirement R2, parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model for the list of items shown below. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions not already included in the studies by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance.

Organization	Question 2 Comment
	• Real and reactive forecasted Load. • Expected transfers. • Expected in service dates of new or modified Transmission Facilities. • Reactive resource capability. • Generation additions, retirements, or other dispatch scenarios. • Controllable Loads and Demand Side Management. • Duration or timing of planned Transmission outages.

Part 2.4.1 is intended to allow the use of aggregated system Load models if more accurate Load models are not available. Therefore, the second and third sentences are not in conflict.

In Part 2.4.1 the SDT specifies the dynamic Load model representation for on peak because the System voltages are generally lower during on peak. The percentage of motor Load, e.g., in air conditioners, could significantly increase reactive power requirements especially when they stall due to low System voltage and can therefore impact dynamic System performance on-peak. However, motor Load would likely not pose the same problem during off-peak as the System voltages are usually higher. So, in Part 2.4.2, it can be left to the discretion of the Planning Coordinator or Transmission Planner whether the dynamic motor Load would need to be represented per the requirement in Part 2.4.1,

Part 2.5.2 has been revised and included as Part 2.6.2 in the new version to provide greater clarity**.**

> **2.6.2** For steady state, short circuit, or Stability analysis: the study shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.

Part 2.7 is intent to require a Corrective Action Plan if the short circuit duty requirement exceeds the current interrupting duty of the circuit breaker. No change made.

3. Requirement R3 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Minor wording changes were made to Requirement R3 to clarify that this requirement pertains to the requirements of the studies needed to support the Planning Assessment. Several industry commenters wanted confirmation that Requirement R3 applied to both the Planning Coordinator and the Transmission Planner feeling that the requirement could result in duplication of effort. The SDT directed the commenters to Requirement R6 (now Requirement R7), which provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment. Several clarifying changes were made to the wording of the parts under Requirement R3 to address industry comments.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.

R3.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5.

R3.3 Contingency analyses shall be performed and:

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.3.3 Ensure relay loadability limits are respected.

R3.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

R3.4 Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.

R3, moderate VSL: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.

Organization	Question 3 Comment
Northeast Power Coordinating Council	R3.3.2 Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 " PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 ? We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible actions" to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R3.4 and R3.5, what defines "more severe System impacts"?
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure that they are being treated within the simulation as they will react in the real world. No change made for this comment. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. R3.4 & R3.5: Requirement R3, parts 3.4 and 3.5 require the Planning Coordinator/Transmission Planner to prepare a list of planning event and extreme event Contingencies that, in the Planning Coordinator's and Transmission Planner's judgment, are expected to produce more severe System impacts, and to document the reasons for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts.	
Transmission Planning	R3.3.1. COMMENT: This would make sense for 3-terminal lines which we are including in contingency files, but for normal 2-terminal lines, very unnecessary. Suggested language at the end would say "Simulation of individual element outages is allowed if it produces an effect more severe that the entire circuit outage". This implies that by modeling individual branch outages would represent more severe conditions than entire circuit outages due to the fact that there would be consequential load loss. R3.4. COMMENT: Table 1 as drafted is very confusing and could be interpreted incorrectly. Recommend revising the header for "Table 1 " Steady State & Stability Performance Extreme Events" Should be changed to "Table 2 - Steady State & Stability Performance Extreme Events" because the expected performance requirements associated with Planning Events could be

Organization	Question 3 Comment
	interpreted to be applicable to Extreme Events as well. Alternatively, the performance requirements at the top of Table 1 need to include a statement that they are applicable to Planning Events only.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an element outage configuration. Please also see footnote 8. No change made. R3.4: The SDT feels that the table headings are sufficiently clear as stated. No change made.	
SERC Engineering Committee Planning Standards Subcommittee	R3.1:In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.: "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. R3.3.1: Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. R3.3.4:In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors:"Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Response: R3.1: The SDT agrees and has modified Requirement R3, part 3.1 accordingly **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote7). No change made. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities	

Organization	Question 3 Comment
	when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.
Modesto Irrigation District	On page 10 under Section R3.3.3, I believe more specifics on what is meant by "relay loadability" need to be given in regard to the requirement of "identify how loadability is analyzed in the steady state simulation". For example, does the analyst need to state that the maximum loading allowed on any system element is less than or equal to 150% of the element's maximum seasonal rating ? We believe that R3.3.1-R3.3.4 should be bullets under R3.3
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
OPUC	3. Requirement R3 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: R3.3 should be modified to become the requirement to conduct contingency analyses with R3.3.1 thru 4 presented as bullets there-under.
Response: R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.	
Bonneville Power Administration	R3.1 should be clarified. Suggested clarification: R3.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R3.4." As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. Requirement R3.4 also needs to be clarified as follows: R3.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R3.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. "The Statement at the end of R3.4 and R4.4 says "rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an

Organization	Question 3 Comment
	explanation of why the remaining Contingencies would exhibit better system performance." The statement does not make sense and should be deleted since the contingencies selected are those to produce more sever system performance. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: R3.1: The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3:The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3 parts 3.3.1- 3.3.4 should be bullets as these are mandatory parts of the required contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu. No change made.

> **R3.3** Contingency analyses shall be performed and:

R3.3.2: The wording has been changed to clarify the intent of the requirement.   For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

> **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.4: The SDT has made a revision to the posted wording of the requirement to add clarity and address your comment.

> **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R3.4 & R4.4: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

> **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible

Organization	Question 3 Comment
	actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.
MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. MRO NSRS suggests this text: "Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: "Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement. **R3.3.3** Ensure relay loadability limits are respected.	
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	R3.3.3 applies to "all Transmission lines. Should this only apply to lines above 230 kV and lines identified as critical below 230 kV" At least this should be limited to BES lines. R3.3.4 says "Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. This should say, "Simulate the expected operation of existing and planned BES devices designed to provide Steady State control of BES electrical system quantities.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT disagrees as this standard only applies to the BES. No change made.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint"? In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. R3.3.1. Recommend that it be clarified that simulation of the more conservative case of a single branch (bus-to-bus) outage is acceptable, as opposed to always simulating the full breaker-to-breaker outage. R3.3.2The requirement needs to be clarified. It is not clear if it is referring to the ability of plants to meet their voltage schedule, or

Organization	Question 3 Comment
	to their ability to stay connected during post contingencies. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. "R3.3.2"For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions? Is this the same as the generator underexcited operation limit?? In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this" R3.3.3"For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. Is the intent that Transmission Planners need to ensure that relay loading limits are included in the facility ratings? Is this the 130% of conductor rating limit?? Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided. In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our Transmission Lines between 100 and 200-kV. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R3.4. ? In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made.

R3.1. The SDT agrees and has modified the requirement.

> **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses a branch outage configuration. Please also see footnote 8 (now footnote 7). No change made.

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage

Organization	Question 3 Comment
limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue of minimum steady state voltage limitations. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. R3.3.4: The SDT agrees and has revised the wording. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
FirstEnergy Corp	Specific comments, Requirements of R3:A. R3: For readability revise "computer simulations using models utilizing data" to "computer simulation models utilizing data" B. R3.3.2: The intent of this requirement is not clear. What is the voltage limitation sought? Vmin at the generator terminals, high-side of the GSU, low-side GSU, etc. Also the requirement text "identify how the generators are analyzed in the steady state simulation" does not drive a particular reliability goal. If the objective is to require tripping of units during a contingency simulation that are identified to be below their stated Vmin then the requirement should clearly state that the unit should be tripped and solution resolved. C. R3.3.3: This requirement should be removed as it is redundant with facility rating requirements stated in PRC-023, FAC-008 and FAC-009. D. R3.3.4: For readability we suggest inserting the word "may" in between "devices include".We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R3
Response: R3: The SDT has revised the wording accordingly.	

Organization	Question 3 Comment
R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The STD has added the word "may" in between "devices include". **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors. Measures, VRF, Time Horizon, Data Retention and VSLs: Thank you for your comment.	
TVA System Planning	In R3.3.2, need guidance on how to consider minimum steady state voltage limitations. Is there a NERC team addressing this? It is not clear if it is referring to the ability of plants to meet their voltage schedule, or to their ability to stay connected during post contingencies. In R3, should the "and" in the first sentence actually be "or"? especially for same footprint? Perhaps the "and" should be replaced by "and/or". Can the PC satisfy this requirement by reviewing studies performed by differing TPs or is separate analysis really required especially when the TP and PC have the same footprint? In the VSL for R3, a severe VSL is listed as failing to meet performance requirement for P0 or P1. We do not understand why a severe VSL would be applied to an all ties closed event which should have little if any problems. We believe that this should be a lower or moderate VSL instead of severe. In R3.3.3 is the relay loadability required for all HV and EHV voltage levels? Previously NERC had required this for 230-kV and above only. This would be massive requirement for our TLs between 100 and 200-kV.
Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. There is a project (PRC-024) that will address this issue. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through	

Organization	Question 3 Comment
	voltage limitations. Include in the assessment any assumptions made. R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner regardless of whether the Planning Coordinator and Transmission Planner footprints overlap or not. No change made. VSL: The SDT disagrees with your assessment. The failure to perform studies to determine the BES meets performance requirement for the P0 and P1 categories is deemed to be severe as these categories represent steady state (no Contingency) and single Contingency (probable) operation and are significant elements of the overall requirement. No change made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.
Exelon Transmission Planning	In R3.3.2 it should be clear that the TP / TO is not required to provide whatever voltage that the unit desires and that the intent of this requirement is to ensure that if a generator is going to trip due to low voltage that the simulation will include the generator tripping. 3.3.2 and 3.3.3. are somewhat redundant with 3.3.1 " suggest rewording 3.3.1 to say including transmission lines with respect to relay loadability and generators with respect to minimum operating voltage. If 3.3.3 is targeting the low voltage ride through capability of the wind generators it should be clear.
	Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world (in your comment 3.3.3 referring to low voltage ride through, we assume in our response that you were referring to 3.3.2) **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.2 & R3.3.3: The SDT does not agree that Requirement R3 parts 3.3.1, 3.3.2 and 3.3.3 are somewhat redundant as they require distinctly different simulation actions. No change made. R3.3.3: This requirement is for all generators, not just wind. It is important for the planning models to accurately reflect how the System will actually perform.
Southern Company	R3.3.3 applies to "all Transmission lines. To be consistent with the relay loadability standard, this should only apply to lines above 230 kV and lines between 100 kV and 230 kV identified as critical. R3.2 and R3.5 are both addressing the Extreme Events. However, R3.2 is referring to R3.5 while R3.5 is referring to R3.2. We suggest deleting the reference back to R3.2 which is in R3.5. A similar situation exists for R3.1 and R3.4. R3 seems to use the words studies and analyses interchangeably. Did the SDT intend for them to be the same? Using one term or the other would be better understood.

Organization	Question 3 Comment
	There are two tables labeled table 1. It would be much clearer to mark them table 1 Planning Events and table 2 Extreme Events.
Response: R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.1 & R3.4 and R3.2 & R3.5: The SDT has decided to retain the back references for clarity. No change made. R3: The SDT agrees that use of studies and analyses can be confusing. The wording in Requirement R3 has been revised to use studies. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that the headings are sufficiently clear to distinguish between planning and extreme events. No change made.	
United Illuminating	R3.3.2 Comment Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment ? PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the	

Organization	Question 3 Comment
possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made.	
System Protection and Transmission Planning Department	R3 appears to require redundant studies by TP and PC.If the TP and PC participate in the same studies, would this meet the intent of this requirement? This would include studies that are RRO sponsored, or performed by sub-regional planning groups.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. Requirement R7 (formerly Requirement R6) provides a mechanism for determining individual and joint responsibilities for performing the required studies for the Planning Assessment regardless of whether the PC and TP footprints overlap or not. No change made.	
PPL Energy Plus	It appears there is a 24 month grace period to allow modeling updates to meet R 3.3.1. This is a good idea since the powerflow computer models may not include the required data and will need to be updated.
Response: Thank you for your comment.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co California ISO Tucson Electric Power Company	As currently drafted, R3.3 is not a requirement. Without the statements in R3.3.1-R3.3.4, R3.3 is simply a phrase. Sub-Sub-Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with the language in R3.3 modified so that it becomes the requirement to conduct contingency analyses that address the four resulting bullets R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automotive voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. R3.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingencies than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R3.3 is unclear. Requirements R3.3.1 through R3.3.4 should be bullets under R3.3, with R3.3 modified so that it becomes the

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td>(NWMT)</td><td>requirement to conduct contingency analyses that address the four resulting bullets

R3.3.2 is unclear. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate. In R3.3.3 the term “loadability” needs to be defined.

R3.5 needs to be modified. It would be better to combine R3.2 with R3.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were deemed to be less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of a redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.</td></tr>
<tr><td colspan="2">Response: R3.3: The SDT has modified the wording to provide greater clarity. The SDT disagrees that Requirement R3, parts 3.3.1- 3.3.4 should be bullets as these are mandatory requirements of the contingency analyses. Bullets are only used to identify the possible but not all inclusive elements of a menu.

R3.3 Contingency analyses shall be performed and:

R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.</td></tr>
<tr><td>Western Area Power Administration</td><td>R3.3.3 should be covered in the PRC Standards. While R3.3 is labeled as “Contingency analysis”, R3.3.4 is related to Steady State control and therefore should not be within R3.3.</td></tr>
<tr><td colspan="2">Response: R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections.

R3.3.3 Ensure relay loadability limits are respected.

R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers, etc., impacts the post-Contingency performance of the System. No change made.</td></tr>
</table>

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td>Tampa Electric</td><td>Consider revising standard for clarity. Subrequirements are not clear as written.

Consider moving subrequirements R3.3.1 - R3.3.4 under other requirements for clarification.

R3.5 Including an explanation of why remaining contingencies would produce less severe system results could be a limitless effort. Listing all "possible" extreme events seems unrealistic.</td></tr>
<tr><td colspan="2">Response: The SDT requires more information in order to respond to your request to clarify the standard and sub-requirements. Numerous clarifications have been made to the fourth posting due to specific industry comments.

R3.3.1-R3.3.4: The SDT disagrees as these are mandatory requirements of the Contingency analyses. No change made.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining contingencies would produce less severe System results”.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.</td></tr>
<tr><td>Florida Reliability Coordinating Council, Inc - Transmission Working Group</td><td>R3.3.1 & 3.3.4 “ Consider adding language that the entity should not be held responsible for simulating “the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention? on neighboring systems, only on the entity’s own system.

Also, consider moving R3.3.1 and R3.3.4 under R3.1 as sub-requirements and require that the overall studies take into account the effect of protection systems and control devices in the performance of the BES and it’s ability to meet the table 1 requirements.

R3.3.1 ? This seems unnecessary for normal 2-terminal lines, consider adding language to the effect of: “Simulation of individual element outages is allowed if it produces an effect more severe than the entire circuit outage”.

R3.4 - Consider changing the header for table 1 - “Steady State & Stability Performance Extreme Events” to Table 2 - “Steady State & Stability Performance Events”. As is, it could be interpreted that the expected performance requirements associated with Planning Events apply to Extreme Events also.</td></tr>
<tr><td colspan="2">Response: R3.3.1 & R3.3.4: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, “the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention” will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1.

R3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.</td></tr>
</table>

Organization	Question 3 Comment
The SDT believes that Requirement R3, parts 3.3.1 and 3.3.4 are separate mandatory requirements and disagrees that they should be moved under Requirement R3, part 3.1. No change made. R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other maintenance scenarios. Planning event P2-1 addresses an individual outage configuration. Please also see footnote 8. No change made. R3.4 Table 1: Based on Industry feedback, the SDT has decided to have one Table and believes that headings are sufficiently clear. No change made.	
FMPA	R3.1, The criteria in Table 1 do not allow load shedding following a single contingency (e.g., the old footnote "b" was removed). While we agree this ought to be the case for the EHV system, we believe that there are cases where for the HV system, which often acts more like a distribution system, the costs to meet this standard would be prohibitive and unfair to the consumers served by those utilities. For instance, the Florida Keys served by the Florida Keys Electric Coop (FKEC) and Keys Energy Services (KEYS) is connected to the mainland by two 138 kV lines down to Tavernier Key (about 1/3rd the distance from the mainland to Key West). Currently, the system is planned and operated under single contingency to allow non consequential load shedding automatically via Under-Voltage Load Shedding, and to meet thermal limits by manual load shedding, all load shed is in the Florida Keys following the single contingency with no impact to the Bulk Electric System. The standard, as written, would force one of two things: 1) the construction of a third line in this environmentally pristine area at a very high cost that might increase rates to customers in the Florida Keys by 20% for a level of reliability that much of the Keys would not even experience since 2/3rds of the Keys is fed by a radial line with consequential load loss; or 2) separate the two lines such that both are operated radially with resultant consequential load loss, compliant with the standards, but actually causing consumers to have a lower level of reliability. We propose to reinstate footnote "b" for the HV system, allowing non-consequential load loss for lower voltage system that have little to no impact on the Bulk Electric System and limit the elimination of non-consequential load loss to be applicable to only the EHV. Alternatively, but less appealing and more of an administrative challenge would be to establish a Regional Entity administered process for application for exception to this criteria. FERC's Order 693 at paragraph 1794 states that: "(t)he Commission also clarifies that an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". We interpret this as meaning the Regional Entity can allow exceptions under certain criteria such as a significant increase in costs to consumers with little discernable benefit as is the case with the Florida Keys. For R3.2, we are at a loss of how a hurricane event can be modeled, and why such an evaluation is needed. Albeit, many contingencies can occur during a hurricane event, it is not likely that multiple contingencies will happen within the same < 1 minute window it takes to go from transient stability conditions to steady state conditions, and then it is unlikely that multiple significant contingency events will occur within the 30 minutes it takes operators to adjust the system to prepare for the next contingency. Therefore, we do not understand the significance of modeling a hurricane event. In addition, a hurricane can have an infinite number of different scenarios and time-lines of contingencies and picking one or two would be a meaningless exercise since an actual hurricane will be completely different than what is modeled. At least an earthquake has a fault line that makes it relatively easier to identify which facilities might be affected, but a hurricane has an infinite number of possibilities. We suggest eliminating hurricanes from extreme events and model potential results of a hurricane, such as loss of a ROW, loss of a substation or plant, and loss of a major load center. R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system (this comment

Organization	Question 3 Comment
	would not carry over to R4.3 since stability is more a protection system / clearing time issue). R3.3.1, the entity should not be held responsible for simulating "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" on neighboring systems, only on the Entity's own system. R3.4 and the first part of R3.5 ought to be combined, e.g., both require justification for why a limited set of worst case contingencies are studied for N-1, N-2 and extreme contingencies. The latter part of R3.5 concerning cascading outages for an extreme contingency should become the only requirement of R3.5 (there are currently two requirements embedded within R3.5).

Response: R3.1: To comply with Order 693, the SDT have decided to raise the performance requirements such that Non-Consequential Load loss should not be allowed for P1 events of Table 1. No change made.

R3.2: Table 1 extreme events: Requirement R3, part 3.5 requires the Planning Coordinator/Transmission Planner to identify and compile a list of the extreme events that are expected to produce more severe System impacts, along with a rationale for selection of those Contingencies. The wide area extreme events such as item 3.iv are provided as examples and not meant to be a mandatory list of events to be simulated. No change made.

R3.3: The SDT assumes that the comment "R3.3, the list ought to consider contingencies on neighboring systems that could impact the TP's / PC's system" actually refers to Requirement R3, part 3.4 where the Contingency list is created. The SDT agrees with your comment and has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. The fourth draft of the standard will include this change by adding Requirement R3, part 3.4.1. The need to include Contingencies on adjacent Systems will also apply to Stability.

> **R3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R3.3.1: The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created in Requirement R3, part 3.4. Consequently, "the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention" will also apply for the Contingencies on adjacent Systems. The fourth draft of the standard will include this change.

R3.4 & R3.5: The SDT does not agree that these requirements should be combined. Requirement R3, part 3.4 requires the development of a Contingency list of planning events, and Requirement R3, part 3.5 requires a Contingency list of extreme events - two separate requirements. The SDT agrees that both require that a rationale be provided for stating why the events selected are expected to produce the more severe System impacts. No change made.

R3.5: The SDT disagrees and sees no reason to split these out as they would still be essentially the same requirement. No change made.

Organization	Question 3 Comment
CPS Energy	Requirement R3.3.2. needs clarification.

Response: R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

> **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through

Organization	Question 3 Comment
	voltage limitations. Include in the assessment any assumptions made.
MidAmerican Energy Company	MidAmerican commends the SDT for it hard wok on this standard and specifically its R3.3.1 wording. MidAmerican has suggestions for the following parts of R3:" . " R3.3.2 " delete the words "For all generators" at the beginning. It is unnecessary in that later in the requirement it states specifically that the responsible entity is to "identify how the generators are analyzed in the steady state limitation". R3.3.3 " use a similar construction to R3.3.2 but delete the words "For all transmission lines". In other words, replace "For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state limitations. With "Studies shall consider relay loadability and identify how loadability for transmission lines is analyzed in the steady state simulations. " R3.4 and R3.5 " change "remaining Contingencies" to "remaining unselected Contingencies".
Response: Thank you for your comments. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis **R3.3.3** Ensure relay loadability limits are respected.. R3.4 & R3.5: The SDT has revised Requirement R3, parts 3.4 and 3.5 by eliminating the requirement to provide the rationale for the unselected Contingencies. **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Northeast Utilities	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to inclusion of R3.3.2 as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is

Organization	Question 3 Comment
	unnecessary and should be deleted. R3.5 Priority Comment - We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
ISO New England, Inc. Central Maine Power Company	R3.3.2 Comment - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 Comment - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.5 Priority Comment -We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.	
JEA	R3. Change wording from "The studies shall be based on computer simulations using models utilizing data provided in Requirement R1." to "The studies shall be based on computer simulations using models that are the best representation of the future planned system and its associated use as provided by Requirement R1. The studies shall detail the effects of all future

Organization	Question 3 Comment
	equipment connectivity and topology arrangements and their associated Protection system responses to Contingency events regardless of model details." R3.3.2. I assume the concern here is on voltage ride through of generators and generator auxillary equipment. Propose changing language from "For all generators..." to"Include analysis of how generator and generator auxillary equipment over and under voltage protection and ride through capability were considered for the post-contingency steady state bus voltage levels." R3.3.3. I assume the concern here is ensuring consideration is given to how system protection relays could respond to post-contingency circuit emergency loadings. Protection systems that could limit the emergency ratings of transmission circuits should be considered in the Facitility Rating standard and therefore not necessary to include in the TPL standard. However, if requirement does remain in the TPL standard, propose changing language from:"For all transmission lines..." to"Include analysis of how implemented relay protection systems and their potential automatic response prior to timely corrective actions are considered for the post-contingency steady state circuit loadings".
Response: The SDT has revised Requirements R1 and R3 to provide greater clarity to the SDT's intent. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected.	
SMUD	R3.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included. R3.3.2:When the word, 'consider' is used, it can be read as a guidance and not a requirement. The requirement is unclear.
Response: R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	

Organization	Question 3 Comment
R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. R3.3.2: The wording has been changed to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.	
Progress Energy Florida, Inc.	Concerning R3.3.1, PEF believes that, in virtually every conceivable scenario, contingency analyses show that analysis of individual elements will reveal overloading or undervoltages, whereas the same event modeled according to protection system design (i.e. simulating the event as the actual “breaker-to-breaker” operation would occur) may not. Analysis of individual elements is therefore a more conservative method for studying the BES. PEF is not opposed to analysis of entire circuit outages; PEF therefore suggests that in addition to the existing language of R3.3.1, an additional sentence be added as follows: “Simulation of the loss of individual elements is acceptable in lieu of simulating the loss of all elements in a protection zone if it produces greater overloads or lower voltages. This approach would allow for more efficient coordination with Transmission Operators as they schedule planned outages or make system adjustments in outage scenarios.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with FERC Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. The requirement does not preclude the Planning Coordinator/Transmission Planner from studying individual elements or other scenarios. Planning event P2-1 addresses an individual element outage configuration. Please also see footnote 8 (now footnote 7). No change made.	
Xcel Energy	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 “ does this imply that mitigation plans must be implemented” If not, then this is highly subjective and the last sentence of this requirement should be deleted.
Response: R3.3.3: The SDT does not agree with your comment**.** No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. No change made.	
Ameren	In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4. Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created

Organization	Question 3 Comment
	in Requirement R3.4. R3.3.2 -For all generators, studies shall consider the minimum steady state voltage limitations and identify how the generators are analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear. It is not clear whether Transmission Planners need to ensure that generating plants can meet their voltage schedule under Base Case (N-0) conditions, or whether this would be the same as the generator underexcited operation limit. R3.3.3?For all Transmission lines, studies shall consider relay loadability and identify how loadability is analyzed in the steady state simulation. The above wording needs to be changed, as the intent of this sentence is unclear, whether the intent is that Transmission Planners ensure that relay loading limits are included in the facility ratings, or whether this reflect some rule of thumb, such as 130% of conductor rating. In Requirement R3.3.4, it is suggested adding the words "and switched" to capacitors and reactors: Simulate the expected operation of existing and planned devices designed to provide Steady State control of electrical system quantities. These devices include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

Response: R3.1: The SDT agrees and has modified the requirement.

R3.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.

R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis

R3.3.3 Ensure relay loadability limits are respected.

R3.3.4: The SDT agrees and has revised the wording to read “and switched capacitors and inductors”.

R3.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.

Organization	Question 3 Comment
Manitoba Hydro	R3.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency list of events created in Requirement R3.4. . R3.2: Requirement wording should be similar to R3.4 for consistency. R3.4 & R3.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation

Organization	Question 3 Comment
	of why the remaining Contingencies would produce less severe System results. without proving this with a study? If the explanation is "that based on engineering judgment, the remaining contingencies would produce less severe system results" then the explanation is implied and not necessary. VSLs: Under the moderate to severe VSL, the performance requirements currently refer to P2 through P7. We believe this is a typo and should be P1 through P7.
Response: R3.1: The SDT agrees and has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSL: The VSL matrix is correct. No change made.	
LCRA Transmission Services Corporation	In R3.3.4, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: R3.3.4 Checking a few dictionary definitions: parameter: "an expression, a constant or variable whose value determines the specific form of the expression; one of an independent variable in a set of parametric equations; whereas quantity is defined as: an exact or specified amount or measure; that property by virtue of which is measurable; extent; measure, size, any amount. It appears that "quantities" is the better choice. No change made.	
National Grid	R3 Comment "Planning Assessment" and "shall perform analysis" are contradictory. R3 and its sub-requirements then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study.R3.1 Comment ? A. It is not clear what should be included in the list related to R3.4. Events P0 through P4 should include analysis of all BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events

Organization	Question 3 Comment
	that are deemed the most significant by the Transmission Planner. B. R3.1 refers to “lists”. Is R3.4 creating one list or multiple lists” Suggest changing “lists” to “list” R3.2 Comment - Since R3.4 and R3.5 both require the responsible entity to create a list, the words in R3.2 be should be revised to be more similar to the words in R3.1. Suggest changing “Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R3.5. to “Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R3.5. R3.3.2 Comment “ A. Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. B. Voltage limitations are for both minimum and maximum. If this requirement is kept, then “minimum” should be deleted. C. Is this requirement really looking at “voltage limits” or generator “reactive capability”? R3.3.3 - This requirement should be deleted. Each reliability issue should be addressed in one standard and relay loadability is addressed in PRC-023. If requirements of PRC-023 are met, the relay loadability does not constitute a limitation. If this requirement is intended to apply to modeling relay characteristics in stability simulations, which is not addressed by PRC-023, then the requirement should be more explicit. However, as written it appears that the intent was to be in-line with Blackout Recommendation 8a which relates to steady-state loadability, which is covered by PRC-023. R3.4 Comment - Table 1 includes both Steady State and Stability events. R3.4 needs to indicate that it only applies to the Steady State portion of the Table. R3.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are too vague to have auditable value. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. – The statement “and shall include an explanation of why the remaining Contingencies would produce less severe System results” is too open and should be deleted. Violation Severity Levels:R3.4 Since this is a binary requirement, should this have a Severe VSL? R3.5 Since this is a binary requirement, should this have a Severe VSL?

Response: R3: The SDT agrees that use of studies and analyses can be confusing and has changed the wording to provide greater clarity.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using

Organization	Question 3 Comment
	data provided in Requirement R1. R3.4: Requirement R3, part 3.4 has been revised to indicate that the Planning Coordinator/Transmission Planner is to produce a Contingency list, of those planning events that are expected to produce more severe results on its portion of the BES. The Planning Coordinator/Transmission Planner is required to identify the Contingency list to be studied and provide the rationale as to why these Contingencies are expected to produce more severe results. There is no requirement to include all BES facilities for P0 to P4. No change made. R3.1: The SDT has changed "lists" to "list". **R3.1** Studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.2: The SDT has revised the wording of the requirement. **R3.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R3, part 3.5. R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and that they are being treated within the simulation as they will react in the real world. The word minimum was retained as the intent is to address low voltage ride through. No change made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. R3.4: Although Table 1 includes both steady state and stability events, Requirement R3 is "for the steady state portion of the Planning Assessment.."; so there is no need for adding further clarification in Requirement R3, part 3.4. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the PC/TP with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would make identification of possible actions optional. No change made. Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining contingencies would produce less severe System results". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed

Organization	Question 3 Comment
to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. VSLs: The VSLs for Requirement R3, parts 3.4 & 3.5 are required elements of the primary requirement. The VSLs categorize noncompliance with the requirement, "in total" – not with each of the individual parts of the requirement. No change made.	
Entergy Services, Inc	In R3.5 what would constitute "an evaluation of possible actions designed to reduce?" R3 should be broken into two pieces where the near term portion could be a Medium VRF but the long term section should be a Low VRF. Violations occuring in the longer term horizon are subjective and assumptions concerning future plans too broad to justify a Medium VRF. In Requirement R3.1, it is suggested that the word "contingency" be added to describe the lists created in R3.4.
Response: R3.5: In the event that an extreme event causes cascading outages, the "possible actions" would be the possible actions that would reduce the likelihood or mitigate the consequences and adverse impacts of the event". VRF: The SDT believes that all of the steady state responses are equally important. No change made. R3.1: The SDT agrees and has revised the wording. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4.	
Great River Energy	R3.3.3 The relay loadability section needs better definition. Is this identifying that: if the relay load limit is the most Limiting Element of a transmission line how it would be handled if it is overloaded considering that there may be some margin before opening the line and/orif the line reaches a certain overload level based on a non-Relay Load Limit being the Most Limiting Element that the relay load limit should be analyzed to see if it will actually activate an opening of the transmission line or the planners need to review all of the relays associated with all transmission lines within the model and indicate if loadability is a concern for each contingency analyzed. There are a lot of lines, (probably the majority), that have not defined a relay capability within the rating fields of the model! This would seem to be a FAC-009 issue. As a discussion point on R3.3.3, it would seem that relay loadability should be addressed in FAC-009 and the Model Building process. Putting this burden in the planning assessment will be difficult to determine if the Most Limiting Element within the model is not a relay load limit as those parameters typically are not the Most Limiting Element. Every line in the model may need to be defined as to what its relay loadability is to meet this requirement. Our regional model build reports a Most Limiting Element, a short term emergency level, and a long-term emergency for the three ratings available within the model. It would seem that the long-term emergency field should be replaced with a Relay Load Limit value such that the R3.3.3 would not be as great of a burden on the planner.
BC Hydro	R3.3.3: Consider changing it to read, "Demonstrate that, for all Transmission lines, relay loadability standards are met in accordance with the PRC series of standards"
Response: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections and to	

Organization	Question 3 Comment
ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 3:A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R3 only says “Long-term Planning”. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: “Near-Term and Long-Term Transmission Planning”. B) Under R3.1 the “Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the lists created in the Requirement 3.4”. We believe that the following language will improve this requirement: Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the more severe contingency lists created in the Requirement 3.4. C) Under R3.3.2 the Midwest ISO generally agrees with FirstEnergy’s comments on this. D) Under R3.3.3 the Midwest ISO feels that this sub-requirement is redundant with PRC-023-2 and therefore we feel that this sub-requirement needs to be removed and replaced with our suggested bullet language under R1.1.2 ? Relay Loadability Limitation (see F on page 3 of 9 above) E) Under R3.4 to make this requirement clearer, please add the following language between the words “expected to” in the first sentence: “expected by the assessing entity to” We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. F) Under R3.5 to make this requirement clearer, please add the following language between the words “expected to” in the first sentence: “expected by the assessing entity to” We believe that this language addition improves the clarity of this requirement. The first sentence would then read: Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.

Organization	Question 3 Comment
• **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.1: The SDT has modified the requirement. **R3.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R3, part 3.4. R3.3.2 The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4 & R3.5: The Planning Coordinator/Transmission Planner are the applicable entities for this standard, so adding "by the assessing entity" is redundant. No change made.	
PJM	In R3, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R3.4 should come before R3.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.5 should come before R3.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. R3.3.2 should be broken into two requirements since two separate tasks need to be performed. R3.3.3 should be broken into two requirements since two separate tasks need to be performed. Also in R3.3.3, analysis of relay loadability will require the inclusion of all relay models 200 kV and above. This information is not presently gathered by the ERAG MMWG for the Eastern Interconnection. To help with compliance, questions R3.3.4 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe contingencies. Would expect a number between 10 and 25 percent. R3.4 should be broken into two requirements since two separate tasks need to be performed. To help with compliance questions, R3.3.5 needs more specificity. Maybe define a minimum percentage of total possible contingencies as a bright line whether you have performed enough more severe extreme contingencies. Would expect a number

Organization	Question 3 Comment
	between 10 and 25 percent. R3.5 should be broken into three requirements since three separate tasks need to be performed.
Response: R3: The SDT believes that the requirement belongs to both the Planning Coordinator and the Transmission Planner. No change made. R3.4 & R3.5: The SDT disagrees. No change made. R3.3.2: The SDT sees this as only one requirement to identify how the generators are analyzed. No change made. R3.3.3: The SDT sees this as only one requirement to identify how the relay loadability is analyzed. No change made. R3.3.3: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. R3.3.4: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made. R3.4: The SDT disagrees as the tasks are related. No change made. R3.3.5: The number of Contingencies is system specific and any percentage that the SDT would establish would be wrong for some entities. No change made R3.5: The SDT disagrees as the tasks are related. No change made.	
Brazos Electric Cooperative	R3.4 and 3.5 give us a concern. Table 1 identifies a number of events that are to be assessed but requiring an explanation of why certain events would produce less severe results seems to be open ended thus making it hard to audit. If all the events in Table 1 are studied or have been studied in the past then what is one supposed to document? we understand this is to allow the planner a certain amount of flexibility in their analysis but it seems counter to the idea of requiring a review of all the events in Table 1. We don't have any suggested wording changes, just passing along a general idea.
Response: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.	
American Electric Power	With regard to R3.3.3., please include transformers as relay loadability also applies to transformers.
Response: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
ITC Holdings	Comments: If the SDT feels that a requirement such as R3.3.4 is necessary, it may also be necessary to identify further limitations on the use of the control devices referred to. For example, a manually controlled phase shifter would require a time period, or loading limits, to readjust flows to limit a post-contingency flow if not pre-set in the pre-contingency state. Similarly, a tap-changing transformer also requires an adjust period for voltage control. We suggest adding a statement to this requirement (or somewhere in performance requirements) that “all post-contingency flows/voltages must remain within the applicable facility ratings before,

Organization	Question 3 Comment
	during, and after the use of such control devices.
Response: The SDT has revised the requirement wording to clarify that the intent is to simulate automatic operation of existing and planned devices. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	
Northern Indiana Public Service Company	R3.3.3: Evaluation of loadability should be triggered only for those circuits with new protection settings issued since the last assessment; evaluation of circuits that have not been newly assigned or re-assign protection settings is a misuse of resources.
Response: The SDT has clarified the requirement to ensure all relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
Minnesota Power	A) Under R3, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R3 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) R3.3.3 Is this sub-requirement redundant with PRC-023-2? Is it covered in FAC-009? We believe the SDT should review these standards and if it is a redundant requirement, then this sub-requirement needs to be removed. C) Under R3.4 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Planning Event Contingencies in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3.1 created. D) Under R3.5 to make this requirement clearer, please add the following language between the words "expected to" in the first sentence so that the phrase reads: "expected by the assessing entity to"? We believe that this language addition improves the clarity of this requirement. The first sentence would then read: "Those Extreme Events in Table 1 that are expected by the assessing entity to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3.2 created.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following:	

Organization	Question 3 Comment
• **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections. **R3.3.3** Ensure relay loadability limits are respected. R3.4& R3.5: The Planning Coordinator/Transmission Planer are the applicable entities, so adding "by the assessing entity" is redundant. No change made.	
LADWP	R3.4 This requirement is very strange. If there is a known planning event that is more severe than those listed in Table 1, it should be so identified in Table 1. It is not fair to ask every planner to search for more severe contingencies without any specifics. R3.4 should be deleted. R3.5 This is similar to R3.4; this requires proving of null set. The only way this requirement can be met is to perform an exhaustive and unlimited list of extreme event, real or imaginery, before a rationale can be rendered. This requirement should be deleted with the exception of the last sentence regarding "cascading outages.
Response: R3.4: Requirement R3.4 has been revised. The intent is not to identify additional Contingencies in addition to the planning events in Table 1, but to identify those Table 1 planning events that are expected to be more severe for your portion of the BES. Based on industry comments, the SDT has deleted the requirement to provide an explanation of "why the remaining Contingencies would produce less severe System performance". **R3.4** Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. R3.4 & R3.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **R3.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.	
Platte River Power Authority	R3.3.3. Zone 3 type relay loadability studies (single and multiple contingency analyses) should be performed in the OPERATING HORIZON to provide results flagged for possible problems to the Relay Engineers who will evaluate a relay setting change on an Facility or a modification to a relay setting for a new Facility about to be put in-service. I do not see the value of Zone 3 relay

Organization	Question 3 Comment
	loadability checks in the Planning Horizon.
Response: The SDT does not agree that relay loadability should be limited to the Operating Horizon. The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	
MAPPCOR	R3.3.2 - Traditionally transmission planners have used their judgment about the minimum steady state voltage limitations of generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R3.3.3 - PRC-023 requires relay loadability to be reflected in facility ratings. Therefore this additional requirement is unnecessary and should be deleted. R3.4 is there a measure for what is a “more severe system impact”? R3.5 Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R3.3.2: The SDT agrees that judgment is used today. There is a project (PRC-024) that will address this issue. The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT believes that the requirement is necessary for the TPL standard and has clarified the requirement in an attempt to remove the objections **R3.3.3** Ensure relay loadability limits are respected. R3.4: Requirement R3, part 3.4 requires the Planning Coordinator/Transmission Planner to prepare a list of planning event Contingencies that, in the Planning Coordinator’s and Transmission Planner’s judgment, are expected to produce more severe System impacts, and to document the rationale for the Contingencies selected. The documented rationale provided by the Planning Coordinator/Transmission Planner will define what is considered to be the more severe System impacts relative to the Contingencies not selected because they are expected to be less severe. No change made. R3.5: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, the SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. The need to identify possible actions addresses an Order 693 directive. Your suggested wording would	

Organization	Question 3 Comment
make identification of possible actions optional. No change made.	
Orlando Utilities Commission	For Requirement 3.3.1 and 3.3.4 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that “studies shall consider” rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation “worse”. The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation.
Response: R3.3.1: The SDT disagrees with the comment as the intent of Requirement R3, part 3.3.1, consistent with Order 693, is to perform the simulation to reflect how the Protection System will operate in the real System for each Contingency without operator intervention. No change made. R3.3.4: The SDT disagrees with your comment. The simulation of the expected operation of devices such as phase-shifting transformers, load tap changing transformers ,etc. impacts post-Contingency the performance of the System. No change made.	
American Transmission Company	We propose the following comments for R3.Revise the R3.3.2 text to clarify that subsequent analysis is performed on generators whose voltages are expected to fall below the minimum voltage limits. We suggest this text: Consider the minimum steady state voltage limitations of all generators and identify how generators with bus voltages below its minimum voltage limits are analyzed in the subsequent steady state simulations. Revise the R3.3.3 text to more clearly relate to the specific requirements in PRC-023. We suggest this text: “Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the steady state simulation. Add R3.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note “e” in the Planning Events, Steady State & Stability section of Table 1. We suggest this text: “Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.
Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world. **R3.3.2** Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected.	

<table>
<tr><th>Organization</th><th>Question 3 Comment</th></tr>
<tr><td colspan="2">R3.3: The SDT disagrees as such planned System adjustments are considered to be operator corrective actions as opposed to automatic actions considered in Requirement R3, part 3.3. No change made.</td></tr>
<tr><td>Idaho Power</td><td>R3.3.2 is unclear as drafted. The minimum steady state voltage limitation for synchronous generators is not a very meaningful value. All generators with an automatic voltage regulator will maintain the set point voltage until the VAR capability of the generator is exceeded, and then the voltage will deteriorate.

R3.5 -The requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study is overly burdensome. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. Listing all possible extreme events could result in a limitless list.</td></tr>
<tr><td colspan="2">Response: R3.3.2: The SDT has changed the wording to clarify the intent of the requirement. For this standard, all that is required is to identify the assumptions concerning voltage limitations of the unit and ensure they are being treated within the simulation as they will react in the real world.

R3.3.2 Trip generators where simulations show generator bus voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

R3.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the Contingencies selected are those to produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining contingencies would produce less severe System results”.

R3.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R3, part 3.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted.</td></tr>
<tr><td>New York Independent System Operator</td><td>R3.5. - The Extreme Events testing in Table 1 should be removed from this standard since there is no requirement to develop a Corrective Action Plan to address unacceptable consequences and the requirements are very general or vague. At a minimum, testing should only be required for EHV facilities or facilities specified by the Regional Entity ? for example, NPCC designates facilities that can have consequences outside an area as bulk power system facilities.</td></tr>
<tr><td colspan="2">Response: R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event. No change made.</td></tr>
<tr><td>Duke Energy</td><td>Revise M3 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.</td></tr>
<tr><td colspan="2">Response: M3: The SDT disagrees. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet</td></tr>
</table>

Organization	Question 3 Comment
the requirements of the TPL standard and to the Corrective Action Plan developed as part of the assessment. The intent of this requirement is to clarify that TPL requirements can be met through joint or shared analysis. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. Therefore, the SDT sees no reason to link Requirement R3 directly to Requirement R6 (now Requirement R7) in the measure or anywhere else. The requirements stand by themselves and do not require such a linkage. No change made	
Independent Electricity System Operator	1. In our opinion, R3 as drafted is rather convoluted as it attempts to cover several objectives. Firstly, we recommend replacing "utilizing data in Requirement R1" with "developed in accordance with Requirement R1" both in the requirement and the VSLs. Secondly, is the main objective of R3 to ensure studies are conducted based on computer simulation utilizing data provided in Requirement R1? Or is it to ensure that this is done, and that all the other objectives are also fulfilled, for example: assessment of system performance (R3.1 and R3.5), conducting the analysis as specified in R3.2 and R3.3, identification of critical Planning Event contingencies (R3.4), etc. If it is the former, then not conducting studies based on computer simulation utilizing data provided in Requirement R1 alone should have a VSL of Severe. If it is the latter, then the requirement should be either: (a) Revised to place all supporting conditions in the subrequirements. As an example, R3 could be revised as follows:R3. The steady state analyses of the Near-Term and Long-Term Planning Assessment as stipulated in R2.1 and R2.2 shall be performed as follows:R3.1. Studies are conducted based on computer simulation utilizing data provided in Requirement R1;R3.2. Studies shall be performed to determine?. (the rest of the existing R3.1) R3.2. The existing R3.3, and so on.This way, not conducting studies based on computer simulation utilizing data provided in Requirement R1 will be "rolled up" to the VSLs for the main requirement, as is currently stated in the VSL table.Or(b) Restructure, if there are multiple main objectives in R3, to clearly have the main objectives in the main requirement, or split it into more than one main requirement.2. Based on the way R3 is written, we agree with the VRF, Time Horizon and Measure. However, we do have a difficulty with the VSL based on our comments above on the requirement, especially on the Moderate VSL for "The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: Requirement R3 has been modified. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1. R3 is a single requirement and the SDT disagrees with the concept of splitting this up into separate requirements. No change made. The moderate VSL has been modified to align with the changes made to the wording of the requirement. **R3, moderate VSL**: The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	
Kansas City Power & Light	R3.3.3: Relay loadability has no bearing beyond the near term horizon. Loadability is not determined several years out. R3.5 " does this imply that mitigation plans must be implemented" If not, then this is highly subjective and the last sentence of this requirement should be deleted.

Organization	Question 3 Comment
Response: R3.3.3 The SDT does not agree that relay loadability should be limited to the near term horizon. The SDT has clarified the requirement to ensure relay loadability limits, as defined in the relay loadability standard, are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.5: extreme events: The SDT disagrees that the standard should mandate corrective actions for extreme events due to the low probability of these events. However, SDT believes that those extreme events that are expected to produce more serve System impacts should be analyzed to assess the extent of the impacts on the System to provide the Planning Coordinator/Transmission Planner with information to decide, where appropriate, if it is reasonable to provide some corrective actions to reduce the possibility or limit the consequences of an extreme event.	
ReliabilityFirst Corporation	R3- Throughout this requirement there is a mention of developing a contingency table. It will be nice that such a table is developed under MOD-010 and MOD-012 standard. ERAG can develop such a list as part of their base case development effort. R3.3.3- Suggest changing it to read "For all Transmission lines, studies shall consider relay loadability, if that is the limiting factor for line loading." R3.3.4 The term "expected operation" is vague. Some of these devices have relays which cause them to automatically respond to system changes, others are controlled by an operator. In both cases, the devices are "expected" to be utilized. Given that operator controlled devices are less certain to be utilized, and may be delayed in being utilized. The expected operation needs to be studied differently for automated devices and those requiring operator interventions.
Response: R3: Requirements R3.4 & R3.5 place the responsibility of creating planning event and extreme event Contingency lists on the applicable entities, the Planning Coordinator and the Transmission Planner as owners, operators or users of the BES. The SDT believes that requirement to develop these Contingency lists of planning and extreme events expected to produce the most severe results, and the rationale for the selection of these events, is best left to the Planning Coordinator/Transmission Planner responsible for its portion of the BES. However, the SDT does not believe that the standard would preclude ERAG from playing a role in the development of these Contingency lists; however, the compliance responsibility will fall to the Planning Coordinator/Transmission Planner. R3.3.3: The SDT has clarified the requirement to ensure relay loadability limits are respected in the analysis. **R3.3.3** Ensure relay loadability limits are respected. R3.3.4: The SDT agrees and has added automatic to the requirement. **R3.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide Steady State control of electrical system quantities when such devices impact the study area. These devices may include equipment such as phase-shifting transformers, load tap changing transformers, and switched capacitors and inductors.	

4. Requirement R4 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: The SDT has made numerous clarifying changes to the requirements due to industry comments. In addition, Requirement R4, part 4.3.3 has been added.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

4.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

4.2 Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

4.3 Contingency analyses shall be performed and:

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.3 Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

4.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

4.4 Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.5 Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.

Footnote 2 Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the

	described in Requirement R4, part 4.5.	that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	performance requirements for three or more of the categories (P1 through P7) in Table 1.

Organization	Question 4 Comment
Dominion - Electric Transmission	R4.4 - Dominion believes that creating a master list of all contingencies a planner must take is burdensome and provides no planning value. In addition the contingencies will vary based on the loading configuration and the specific study case. In general, we start out with the very worst contingencies. If these cause hard rotor swings, we know we will probably have to do most of the possible contingencies in the station until we get down to contingencies that do not swing the generator much. But if the swings are light, then that particular load/topology situation probably does not need in-depth exploration. Creating a master list could create unnecessary study. However, we do support a list of the extreme contingencies in R4.5.
Response: Requirement R4, part R4.4 does not require a master list of all possible contingencies. The requirement is to create a list of those Contingencies expected to produce more severe results. There is nothing that prevents you from modifying the list based on simulation results (e.g., hard rotor swings). No change made.	
Northeast Power Coordinating Council	R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to

Organization	Question 4 Comment
	address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events- Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. For Requirements R4.4 and R4.5, what defines “more severe System impacts”?
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should just document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made. R4.4 and R4.5: The definition of "more severe impacts" is left to the engineering judgment of the Transmission Planner and Planning Coordinator.	
Transmission Planning	R4.3.2. COMMENT: The inability to survive a given low voltage transient is often dependent on motor performance within the generating facility’s auxiliary load distribution system and is not a specific relay setting. Determination of specific generating plant low voltage ride through capability requires extensive modeling of the plant distribution system and is outside the scope of this standard.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
SERC Engineering Committee Planning Standards Subcommittee	R4.1:In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4?Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. R4.4:Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:? For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information

<table>
<tr><th>Organization</th><th>Question 4 Comment</th></tr>
<tr><td></td><td>with an explanation of why the remaining Contingencies would produce less severe System results.

R4.3.2:R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity.

Footnote #3:Footnote #3 needs to be revised to include 2LG faults in addition to 3-Phase faults indicating that the SLG criteria is met.</td></tr>
<tr><td colspan="2">Response: R4.1: The SDT agrees and has added the word "Contingency".

4.1 Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

R4.4: The SDT agrees and has modified the wording similar to your suggested wording, however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard.

4.4 Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording.

Footnote 2 Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.</td></tr>
<tr><td>Modesto Irrigation District</td><td>Comments: We believe that R4.3.1-R4.3.3 should be bullets under R4.3</td></tr>
<tr><td colspan="2">Response: R4.3.1-R4.3.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. No change made.</td></tr>
<tr><td>OPUC</td><td>4. Requirement R4 ? Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Comments: A: R4.3 should be modified to become the requirement to conduct contingency analyses with R4.3.1 thru 3</td></tr>
</table>

Organization	Question 4 Comment
	presented as bullets there-under. B: R4.3.2 should clarify whether all relay protection must be modeled
Response: R4.3: The SDT disagrees as these are mandatory requirements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, R4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Bonneville Power Administration	Requirement R4 should be consistent with R3. Suggested edit for R4. - "For the Stability portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term Transmission Planning Horizon studies in Requirement R2.4. The studies shall be based on computer simulations using models developed from the data provided in Requirement R1." R4.1 should be clarified consistent with comments to R3.1. Suggested clarification for R4.1 - "Studies shall be performed to determine whether the BES meets the performance requirements in Table 1. A reduced set of contingencies can be simulated based on a list created in requirement R4.4." As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 ? it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. Requirement R4.4 also needs to be clarified as follows: R4.4 - "A reduced list of Contingencies can be developed for System Performance evaluation in Requirement R4.1 that includes those Planning Event Contingencies that are expected to produce more severe System impacts based on system performance as required in Table 1. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then

Organization	Question 4 Comment
	simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.

Response: The wording in Requirement R4 has been made identical to that in Requirement R3.

> **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2, parts 2.4 and 2.5, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table 1. The studies shall be based on computer simulation models using data provided in Requirement R1.

R4.1: The intent is to run the contingencies developed in Requirement R4, part 4.4, not a reduced set of them. No change made.

R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below.

> **4.3** Contingency analyses shall be performed and:

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.4: The intent of Requirement R4, part 4.4 is to identify and develop a list of Contingencies to be run. Your proposed wording does not capture that intent. No change made.

R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.

Organization	Question 4 Comment
MRO MRO NERC Standards Review Subcommittee	MRO NSRS proposes the following comments for R4:Add R4.3.3 text include relay loadability in the R4 (Stability) requirements to parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. MRO NSRS suggests this text: “Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation. In R4.3.4, MRO NSRS proposes limiting the scope to automatic devices and adding the notion of “including but not limited to”. MRO NSRS suggests R4.3.4 text of: “Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

Response: R4.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a stability requirement for relay loadability. This requirement is more applicable to stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state

Organization	Question 4 Comment
issue than a dynamic issue. **4.3.3** Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers. R4.3.4: The SDT has added the word "automatic" into Requirement R4, part 4.3.4 such that it now reads as follows: **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In R4, should the "and" in the first sentence actually be "or"?" Footnote #3 needs to be revised to include 2LG faults in addition to 3Phase faults indicating that the SLG criteria is met. In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4"Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. ? Regarding Requirement R4.4, it is suggested that a rewording be considered such as the following: For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results. ? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. ? R4.3.2 ? By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met. In R4.3.2, need guidance on how to consider minimum steady state voltage limitations.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that 'AND' is the proper word rather than 'OR'. Using 'OR' could be interpreted by one entity as not applying to them. No change made. Footnote #3 (now footnote #2): The SDT agrees and has made the suggested change. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. R4.1: The SDT agrees and has made the suggested change. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.	

Organization	Question 4 Comment
R4.4: The SDT agrees and has made the suggested change however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard. **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
FirstEnergy Corp	Specific comments, Requirements of R4:A. R4.1: A space is needed between the text "Requirement and R4.4" which are run together in the requirement. B. R4.3.3: For readability we suggest inserting the word "may" in between "devices include". We agree with the stated Measures, VRF, Time-Horizon, Data Retention and VSL of requirement R4
Response: R4.1: The SDT has corrected this problem. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.3.3: The SDT agrees and has made the suggested change. **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.	
TVA System Planning	In R4, should the “and” in the first sentence actually be “or”? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. The SDT believes that ‘AND’ is the proper word rather than ‘OR’. Using OR could be interpreted by one entity as not applying to them. No change made. R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of	

Organization	Question 4 Comment
all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Exelon Transmission Planning	See comment in response to question 9 regarding the lack of definition related to the failure of a “single Protection System”.
Response: See response to question 9 comment.	
Southern Company	Generating unit stability should be separated from system stability like in previous drafts. R4.2 and R4.5 are both addressing the extreme events. However, R4.2 is referring to R4.5 while R4.5 is referring to R4.2. We suggest deleting the reference back to R4.2 which is in R4.5. A similar situation exists for R4.1 and R4.4.
Response: The majority of the industry believes that there should be no distinction between generating unit stability and System Stability. No change made. R4.2, R4.5, R4.1, R4.4: The SDT does not see any harm in having the cross referencing. No change made.	
United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?We recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events- It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better	

Organization	Question 4 Comment
than your suggested words. No change made.	
System Protection and Transmission Planning Department	Comments under R1 apply here as well. The requirement to "utiliz[e] data provided in Requirement R1" is redundant with MOD-012, and should be moved to MOD-012. To conform with R1, we suggest a phrase be inserted that requires model data used in Stability Studies used for Annual Assessments be consistent with data submitted under MOD-012.
Response: R4: MOD-012 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to utilize data provided under Requirement R1 is needed in this standard. No change made. R4: Because Requirement R1 references the data provided under MOD-012, there is no need for a reference to MOD-012 in Requirement R4. No change made.	
PPL Energy Plus	It should be pointed out that Breaker Failure (i.e. fail to open) and Breaker Fault (internal fault in breaker) are two different events.
Response: Breaker failure and breaker fault are two different events and that is reflected by having two different designations for these events in Table 1 (P2.3 and P4). No change made.	
PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy San Diego Gas and Electric Co Tucson Electric Power Company	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 - it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 ? We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
NorthWestern Corporation NorthWestern Energy (NWE)	R4.3 is unclear. Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets

Organization	Question 4 Comment
(NWMT)	R4.3.2 is unclear. It appears to be a broken sentence. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. It is our understanding that the voltage ride through standard is not complete at this time. R4.5 needs to be modified. It would be better to combine R4.2 and R4.5. The first part of the requirement requires identification of events that produce more severe System impacts. The presumed reason that the other contingencies were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be examples of more severe Extreme Contingencies than the one selected for study. This can be achieved by simply choosing events that are even less credible. For example, if the Extreme Contingency studied was a simultaneous loss of 3 transmission lines with the failure of redundant RAS (SPS), then an event resulting in the simultaneous loss of 4 lines with the failure of 2 sets of redundant RASs would be even more severe. Listing all possible extreme events could result in a limitless list.
Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
Western Area Power Administration	R4.3.3 need not include the operation of exciters and power system stabilizers as modeling of these parts of a generation system is already covered in Mod-12 & Mod-13 Standards and therefore are inherent in the dynamic analysis conducted using a program such as the GE PSLF or PTI power system simulation programs.
Response: R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.	
Tampa Electric	Clarification needed on modeling of protection system equipment.
Response: Requirement R4, parts 4.3.1 and 4.3.2 do not require modeling of Protection System equipment. It just requires you to have simulations which include the effect of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. No change made.	

Organization	Question 4 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	R4.3.1 - Please clarify, is the intent of this requirement to have every relay modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relays in Canada). R4.4 & R4.5 - Does the intent of allowing this "More severe events" to establish actual study parameter extend between the planned events and extreme events (e.g. if a range of extreme events establishes that planning events performance requirements are met, would a redundant analysis of the planning events still be required)
Response: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker contingency is met). No change made.	
FMPA	R4.2, see comment on R3.3 concerning how to model a hurricane event or other weather event. R4.3, contingency analysis ought to specifically exclude studying contingencies on neighboring systems since stability is more related to protection system and clearing times. R4.3.1, please clarify, is the intent of this requirement to have every distance relay in each Interconnect modeled? We suggest clarifying that the intent is that Protection System Equipment would be incorporated into Facility Ratings and the contingency list, and that modeling the Protection System equipment settings and logic would only be done for Protection Systems that could significantly impact stability response (e.g., out-of-step relaying) as deemed appropriate through engineering judgment, and that the intent would be to do this only for the Region under study and not the entire Interconnection (e.g., studies in Florida should not need to include relay models in Canada). R4.3.2, we assume that the intent of this requirement would be to help establish the magnitude and duration of acceptable post-transient voltage dips, presumable to meet the curve published in the PRC-023 standard under draft. Is this a correct assumption? We assume the drafting team does not expect models to be written for every generator to actually model potential loss of station service due to voltage dips and automatically model potential generator trips. R4.4 and R4.5, see comments on R3.4 and R3.5 about re-arranging these requirements.
Response: R4.2: There are no hurricane events or weather events in the extreme events for stability analysis. No change made. R4.3: The SDT disagrees. There may be some contingencies on external systems which can have a dynamic impact on the system under study. Part 4.4.1 has been added to Requirement R4 to address this possibility.	

Organization	Question 4 Comment
4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. R4.3.1: Requirement R4, part 4.3.1 does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. Certainly engineering judgment should be used to determine which relay effects should be included in the simulations. No change made. R4.3.2: The intent of this requirement is to include in the Planning Assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the Planning Assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4 and R5: The SDT does not agree that the requirements should be re-ordered. No change made.	
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican suggests that R4.5 be revised by changing “remaining Contingencies” to “remaining unselected Contingencies.
Response: R4.5: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”. **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	
SMUD	R4.3:R4.3.2 - The requirement is unclear. If it is to cover modeling issues, then it should be under MOD series. If it is to cover voltage ride through performance, then performance metrics should be provided. R4.5Listing all possible scenarios for studying extreme contingencies will result in a limitless list. Discretion should be given to the transmission planner on the selection of the contingencies without a requirement to list why other extreme contingencies have not been included.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.	

Organization	Question 4 Comment
4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
Progress Energy Florida, Inc.	For R4.3.2, PEF assumes that the SDT understands that the extent of analyzing generation voltage ride-through capability does not extend to modeling of individual inductive loads on the Distribution side, as this does not fit the definition of the BES. Motor loads on the Distribution system do have an effect on generation voltage ride-through capability, however, and PEF therefore is perplexed as to what extent the SDT expects concerning analysis for this sub-requirement.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
Xcel Energy	R4.3 - requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies, have the costs of this requirement been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 - to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
Ameren	In Requirement R4.1, it is suggested that the word "contingency" be added to describe the lists created in R4.4Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists created in Requirement R4.4. Regarding Requirement R4.4, it is suggested that a rewording be considered such as described below:For each category of the Planning Events in Table 1, those Planning Event Contingencies that are expected to produce more severe System impacts shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4.1 shall be created. The rationale for the Contingencies selected for evaluation shall be available as supporting information with an explanation of why the remaining Contingencies would produce less severe System results.

Organization	Question 4 Comment
	R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed. e.g. auxiliary loads, generator protection, generator capability, etc. We would like to see more clarity on this requirement. It seems that the stuck breaker scenarios would always be more severe than the internal breaker failure scenario since they would be clearing in delayed clearing time and thus make P2.3 redundant. Are there is some question on whether P3 contingencies would be necessary for stability analysis. Revise wording in VSL from “categories” to “applicable categories”. e.g. some entities may not have common tower facilities and thus there would be no P7 category contingencies to evaluate. Footnote #3 needs to be revised to include Double-Line-To-Ground faults in addition to Three-Phase faults indicating that the SLG criteria is met.

Response: R4.1: The SDT agrees and has added the word "Contingency".

> **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

R4.4: The SDT agrees and has modified the wording similar to your suggested wording however - due to other stakeholder comments, the phrase requiring an explanation was deleted from the revised standard.

> **4.4** Those planning events in Table 1that are expected to produce more severe System impacts on its portion of the BES, shall be identified, and a list of those Contingencies to be evaluated for System performance in Requirement R4, part 4.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information.

R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of a generating plant's distribution system. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

Stuck breaker comment: A stuck breaker scenario would not always be more severe than an internal breaker fault. Depending on the location of CTs and PTs, an internal fault could take longer to clear.

P3 comment: Fault induced delayed voltage recovery simulations could be more severe in a Load area when a generator is out of service. Therefore, P3 events are applicable to Stability analysis.

VSL: The SDT does not believe it is necessary to add the word "applicable" in front of "categories" in the VSL for Requirement R4. The requirement in Part 4.1 is to study the list (Part 4.4) of "Those planning event Contingencies in Table 1 that are expected to produce more severe System impacts". If you have no applicable events in one of the categories, then just state that in the Planning Assessment. This will not be considered as not performing a study for one of the categories.

Organization	Question 4 Comment			
R4 VSL	The responsible entity did not identify planning events as described in Requirement R4, part 4.4 or extreme events as described in Requirement R4, part 4.5.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for one of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform studies as specified in Requirement R4, part 4.2 to assess the impact of extreme events. OR The responsible entity did not base its studies on computer simulation models using data provided in Requirement R1.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for two of the categories (P1 through P7) in Table 1. OR The responsible entity did not perform Contingency analysis as described in Requirement R4, part 4.3.	The responsible entity did not perform studies as specified in Requirement R4, part 4.1 to determine that the BES meets the performance requirements for three or more of the categories (P1 through P7) in Table 1.
Footnote #3 (now footnote #2): The SDT agrees and has modified the wording similar to your suggested wording. **Footnote 2** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.				
Manitoba Hydro	R4.1: The requirement text should be changed to read “studies shall be performed for Planning Events to determine whether the BES meets the performance requirements in Table 1 based on the contingency lists of events created in Requirement R4.4. R4.2: Requirement wording should be similar to R4.4 for consistency. R4.3: We agree that consideration of generator voltage ride through is important. However, we also suggest that frequency ride through capability be analyzed. R4.4 & R4.5: The selection of the contingency list is based on the knowledge of the PC/TP. How do you produce “an explanation of why the remaining Contingencies would produce less severe System results. without proving this with a study” If the explanation is “that based on engineering judgment, the remaining contingencies would produce less severe system results” then the explanation is implied and not necessary.			

Organization	Question 4 Comment
Response: R4.1: The SDT agrees and has changed the wording similar to your suggestion. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2: The SDT does not understand this comment. No change made. R4.3: Frequency ride-through for generators would only be needed for a limited number of simulations, and therefore the SDT does not see the need to make a general requirement for this. No change made. R4.4 and R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results".	
LCRA Transmission Services Corporation	In R4.3.3, what is meant by the term "electrical system quantities"? Quantities is typically an amount and its use here would indicate that a term such as parameters would be better suited.
Response: "Electrical system quantities" are items such as voltage, current, power, etc. The SDT believes the use of this term is appropriate in Requirement R4, part 4.3.3 (now 4.3.4). No change made.	
National Grid	R4 Comment " "Planning Assessment" and "shall perform analysis" are contradictory. R4 and its sub-requirements, then reference study requirements. If this is an assessment, then the standard shouldn't be requiring a study. R4.1 Comment ? A. It is not clear what should be included in the list related to R4.4. Events P0 through P4 should include analysis of all facilities BES facilities for which the Transmission Planner is responsible. Events P5 and higher should be limited to contingency events that are deemed the most significant by the Transmission Planner. B. R4.1 refers to "lists". Is R4.4 creating one list or multiple lists? Suggest changing "lists" to "list" R4.2 Comment - Since R4.4 and R4.5 both require the responsible entity to create a list, the words in R4.2 be should be revised to be more similar to the words in R4.1. Suggest changing "Studies shall be performed to assess the impact of the Extreme Events identified in Requirement R4.5. " to "Studies shall be performed to assess the impact of the Extreme Events, which are identified by the list created in Requirement R4.5. R4.3.2 Priority Comment - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard. R4.5 Priority Comment ?It is recommended that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. If the requirement is not deleted, the following is recommended:- Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events. If not, it will be difficult to utilize the results to obtain projects approvals.- It should be clear that an evaluation does not require solution development for all Extreme Events- Change "an evaluation of possible

Organization	Question 4 Comment
	actions"? to "where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered. - The statement "and shall include an explanation of why the remaining Contingencies would produce less severe System results" is too open and should be deleted. Violation Severity Levels:R4.4 Since this is a binary requirement, should this have a Severe VS? R4.5 Since this is a binary requirement, should this have a Severe VSL?

Response: R4: The SDT does not see a contradiction. Requirement R4 is a study requirement. The assessment requirement for stability is Requirement R2, part 2.4 and requires the use of current or past studies. No change made.

R4.1A: The SDT disagrees. P1 - P4 (P0 not applicable to Stability) should be run for those Contingencies expected to produce more severe results. It is not necessary to study faults on every line in the System. No change made.

R4.1B: The SDT agrees and has changed "lists" to "list".

> **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4.

R4.2: The SDT agrees and has changed to your suggested wording.

> **4.2** Studies shall be performed to assess the impact of the extreme events which are identified by the list created in Requirement R4, part 4.5.

R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

> **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made.

R4.4 and R4.5 VSLs: The VSLs are based on taking Requirement R4 as a whole with Requirement R4, parts 4.4 and 4.5 being portions of that whole. The SDT does not think that failing to create a list of Contingencies should be a severe violation. When taking Requirement R4 as a whole, failing to create the list was deemed to be lower violations. No change made.

Organization	Question 4 Comment
Entergy Services, Inc	In R4.5 what would constitute "an evaluation of possible actions designed to reduce?"? R4.3.2 requires that voltage ride through capability be analyzed. It is not clear what should be analyzed (e.g. auxiliary loads, generator protection, generator capability, etc.) This requirement needs more clarity. " R4.3.2 " By in large, the industry does not have the input data or the methods to do this. It would seem necessary to have PRC-024 approved before this can be met.

Organization	Question 4 Comment
Response: R4.5: "An evaluation of actions designed to reduce" means looking for ways to reduce the probability of the event occurring or reducing the magnitude of the consequences of that event. For example, if a three phase fault with a bus differential failing to operate results in the collapse of a large Load area, a possible action would be to add a redundant bus differential relay. This reduces the probability of the event occurring. Or if a three phase fault with a stuck breaker results in a large area of the system pulling out of synchronism, an SPS could be used to trip a generator and keep the rest of the system in synchronism. This would reduce the magnitude of the consequences of the event. The evaluation would be comparing potential solutions and their cost with the consequences of the event to determine the best course of action to take (if any). R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	
BC Hydro	Comments: Consider changing R4.3.2 to, “Confirm proper generator performance under anticipated conditions including low voltage ride-through capability” In R4.3.3, change “VAR” to “var”. The IEC has adopted the name var, var (volt ampere reactive power), for the coherent SI unit volt ampere for reactive power. (see: http://www.iec.ch/zone/si/si_elecmag.htm#si_rpo). Is there an overlap between R4.3.3 and the MOD standards? If so, perhaps R4.3.3 should be deleted. If not, perhaps the MOD standard should be expanded to include this. Consider adding R4.3.4, “not simulate any operator intervention”
Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.3.3: The SDT agrees and has changed "VAR" to "var". **4.3.4** Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers. R4.3.3: MOD-012 and MOD-013 do not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made. R4.3.4: The SDT does not think it is necessary to add "not simulate any operator intervention". If operator intervention is appropriate in the time frame of the study, then simulate it. No change made.	
Midwest ISO	Opening Remarks. Specific Comments for Requirement 4:

Organization	Question 4 Comment
	A) Under R4, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Minnesota Power	Under R4, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R4 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

Organization	Question 4 Comment
PJM	In R4, why require a Planning Coordinator AND a Transmission Planner to perform this analysis? Isn't this a duplication of effort? R4.4 should come before R4.1. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. Also in R4.1, a space is needed between "Requirement" and -R4.4-. R4.5 should come before R4.2. You should never reference down in a standard. Please present the items in the order in which they should be performed/considered. In R4.2.3, I question whether the existing dynamics models can evaluate voltage ride through. If you are just talking about modeling voltage protection of generators then maybe, but this protection information is presently not collected by the ERAG MMWG for the Eastern Interconnection. R4.4 should be broken into two requirements since two separate tasks need to be performed. R4.5 should be broken into three requirements since three separate tasks need to be performed.

Organization	Question 4 Comment
Response: R4: Requiring the Planning Coordinator AND the Transmission Planner to perform analysis should not result in a duplication of effort. Requirement R6 (now Requirement R7) requires the two entities to agree on their individual and joint responsibilities. No change made. R4.4 & R4.5: The SDT does not believe that re-ordering the requirements serves any purpose. No change made. R4.1: The SDT has revised the requirement. **4.1** Studies shall be performed for planning events to determine whether the BES meets the performance requirements in Table 1 based on the Contingency list created in Requirement R4, part 4.4. R4.2.3: The SDT assumes you meant Requirement R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.4: The SDT disagrees that this requirement should be broken into two requirements. There are not two independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made. R4.5: The SDT disagrees that this requirement should be broken into three requirements. There are not three independent tasks in the requirement. The tasks are inherently correlated and will be assessed as part of the primary Requirement R4. No change made.	
Brazos Electric Cooperative	Same general comment in 4.4 and 4.5 about the requirement to maintain documentation on why certain events would produce less severe results.
Response: Several industry commenters have indicated that an explanation of “why the remaining Contingencies would produce less severe System performance” should be deleted since the contingencies selected are already justified as those that produce more severe System performance. The SDT agrees and has deleted the requirement for an “explanation of why the remaining Contingencies would produce less severe System results”.	
American Electric Power	The cross-referencing between R4.1 and R4.4, and between R4.2 and R4.5, seems to add unnecessary complexity and could be eliminated by merging each of these pairs of sub-requirements. Under the event column of Table 1 of the proposed TPL standard, considering entries P3 and P6, the option to apply either SLG or 3-phase fault types should be retained to be consistent with the existing TPL standards, which permit either SLG or 3-phase faults (see existing Table 1, Category B and Category C3). If the SDT decides not to make the requested change, then the SDT should give recognition to the unique characteristics of 765 kV lines where permanent 3-phase faults are virtually non-existent. AEP’s 765 kV transmission facilities have been successfully planned and operated with only a SLG fault criterion. Therefore, Table 1 Planning Events P3 and P6 should permit application of SLG faults.
Response: The SDT does not see any harm in having the cross referencing. No change made.	

<table>
<tr><th>Organization</th><th>Question 4 Comment</th></tr>
<tr><td colspan="2">Table 1: Requirement R1.3.1 in TPL-002-0a states that simulations should "Be performed and evaluated only for those Category B Contingencies that would produce the more severe System results or impacts." The SDT believes that the intent of the existing TPL standards is to simulate the worst case whether three phase or single-line-to-ground. The new standard is clarifying that three-phase is required for single Contingency events. No change made. Note that AEP may request an entity variance from this part of the standard.</td></tr>
<tr><td>ITC Holdings</td><td>Comments: In R2.5.1, a limitation is identified for stability studies that are used to support the annual assessment be less than five calendar years old. Should this reference be included in R4??</td></tr>
<tr><td colspan="2">Response: R4: Because the five year limitation is stated in Requirement R2, part 2.5.1, there is no need to repeat it in Requirement R4. No change made.</td></tr>
<tr><td>LADWP</td><td>R4.5 See coments on R3.4 and 3.5</td></tr>
<tr><td colspan="2">Response: See response to comments for Requirement R3, parts 3.4 and 3.5.</td></tr>
<tr><td>Platte River Power Authority</td><td>R4.3.2. Delete this requirement as it is covered under MOD-013-1, R1.2 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies.

R4.3.3. Delete this requirement as it is covered under MOD-013-1, R1.2 and R1.3 for RRO Dynamics Data requirements. When the generator is modeled accordingly the generator's performance will be simulated and analyzed in the stability studies.</td></tr>
<tr><td colspan="2">Response: R4.3.2: The SDT has changed the wording of Requirement R4, part 4.3.2 for additional clarification. This does not require the modeling of generator relays although that is one method that could be used to meet the requirement.

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

R4.3.3: MOD-013 does not require the data to be used for an assessment of the Transmission System. Therefore, the requirement to simulate the operation of exciters and stabilizers is needed in this standard. No change made.</td></tr>
<tr><td>MAPPCOR</td><td>R4.3.2 - Traditionally transmission planners have assumed that generators would ride through low voltages associated with Planning Events which is generally adequate for non-wind generators. If this standard is going to require its incorporation into the assessments, there should be an MOD standard developed requiring the generators to provide the necessary information prior to its inclusion as a requirement in this standard.

R4.5 -Recommend that the requirement for Extreme Event testing be removed from this standard as there is no requirement to develop a Corrective Action Plan to address unacceptable consequences. Otherwise we recommend the following:-Extreme Event performance should be a consideration when developing Corrective Action Plans to address Planning Events-It should be clear that an evaluation does not require solution development for all Extreme Events-Change “an evaluation of possible actions”? to “where appropriate, reasonably practicable actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be considered.</td></tr>
</table>

Organization	Question 4 Comment
Response: R4.3.2: There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. Requirement R4, part 4.3.2 requires you to include in the assessment how you analyzed voltage ride-through capability. If complete information on the ride-through capability is not available, then you should document your assumptions regarding ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: The SDT considers extreme event testing to be an important part of the assessment and therefore will not delete it. The expectation for extreme event testing is that for major problems you will evaluate actions to reduce likelihood or mitigate consequences. The SDT believes the original words express this concept better than your suggested words. No change made.	
Orlando Utilities Commission	For Requirement 4.3.1 and 4.3.3 I suggest adding language similar to 3.3.2 and 3.3.3 establishing that “studies shall consider” rather then requiring every simulation precisely recreate this usually minor part of system performance. These devices generally do not respond except for a nearby event, and even then their response is rarely such that it would make the situation “worse”. The effect of these devices must be considered, but mandating that every simulation faithfully reproduce the response of every device is not only an efficient way to do this, it actually provides a counter incentive to going above and beyond the standard requirements. Any simulation used to meet this standard that failed to precisely reproduce the performance of this equipment would be a violation of this requirement (as currently written). As such there is no incentive for an entity to include anything but the absolute minimum number of simulations required to meet the standard, since each extra simulation represents an opportunity to miss this requirement. Good planning is based on running a broad range of events against a broad range of conditions and evaluating those responses against a set of performance criteria. This is encouraged by requiring that studies consider the response of equipment to these events rather then mandating their precise reproduction in simulation. Requirement 4.4 and 4.5 establish that only those events that would cause the most severe system impacts should be studied. This is an excellent requirement since it focuses the large resource requirement in performing these studies on the events that will provide the best information. Does the intent of the “More severe events” to establish actual study parameter extend between the planned events (R4.4) and extreme events (R4.5)? Or phrased another way, if an entity selects a proper range of extreme events and establishes that planning event performance requirements are met, could that be used as evidence that R4.4 is met as well, or would R4.4 require the same conditions be reproduced in their less severe configuration.
Response: R4.3.1: The SDT believes you should simulate the removal of System elements that Protection System and other controls would remove, not just consider it. No change made. R4.3.3 (now Part 4.3.4): The SDT has clarified that the devices to be included in the study which provide dynamic control are those that impact the study area. R4.4 and R4.5: You can always demonstrate that performance requirements are met by meeting them for a more severe Contingency. It is possible that you could demonstrate that performance requirements are met for planning events by performing extreme events (e.g., using a three-phase fault with stuck breaker Contingency can demonstrate that performance requirements for a single phase fault plus stuck breaker Contingency is met).	
American Transmission	We propose the following comments for R4:Add R4.3.3 text to include relay loadability in the R4 (Stability) requirements to

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<tr><th>Organization</th><th>Question 4 Comment</th></tr>
<tr><td>Company</td><td>parallel R3.3.3 in the R3 (Steady State) requirement which would more clearly relate to the specific requirements in PRC-023. We suggest this text: “Incorporate relay loadability per PRC-023 and identify how relay loadability is analyzed in the dynamic simulation.

In R4.3.4, we propose limiting the scope to automatic devices and adding the notion of “including but not limited to”. We suggest R4.3.4 text of: “Simulate the expected automatic operation of existing and planned control devices including but not limited to generation exciter control and power system stabilizers, static VAR compensators, power flow controllers, and DC Transmission controllers.

Add R4.3.5. The obligation to consider only planned System adjustments that are executable should be a Requirement, rather than performance note “e” in the Planning Events, Steady State & Stability section of Table 1. We suggest this text that matches R3.3.5: “Consider planned System adjustments, such as Transmission configuration changes and redispatch of generation, that are executable within the time duration of the applicable Facility Ratings.</td></tr>
<tr><td colspan="2">Response: R4.3.3: The SDT agrees with the general idea and has added Requirement R4, part 4.3.3. However, Requirement R4, part 4.3.3 requires that you "Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers" rather than creating a Stability requirement for relay loadability. This requirement is more applicable to Stability studies than a relay loadability requirement would be. Relay loadability is more of a steady state issue than a dynamic issue.

4.3.3 Simulate the impact of transient swings on Protection System operation for Transmission lines and transformers.

R4.3.4: The SDT has made the suggested changes.

4.3.4 Simulate the expected automatic operation of existing and planned devices designed to provide dynamic control of electrical system quantities when such devices impact the study area. These devices may include equipment such as generation exciter control and power system stabilizers, static var compensators, power flow controllers, and DC Transmission controllers.

R4.3.5: Header note ‘e’ gives permission to use System adjustments under certain conditions. This is not a requirement and doesn't need to be included in Requirement R4. No change made.</td></tr>
<tr><td>Idaho Power</td><td>R4.3.2 Generation protection system contain up to a dozen tripping functions functions. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system.R4.5 ? Again I disagree with this requirement. It is the same as R3.5 and overly burdensome.</td></tr>
<tr><td colspan="2">Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require extensive modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this.

4.3.2 Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.</td></tr>
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Organization	Question 4 Comment
Duke Energy	Revise M4 to include a reference to R6, since the allocation of responsibilities will directly affect the evidence which is to be provided.
Response: M4: The SDT disagrees. No change made.	
California ISO	As currently drafted, R4.3 is not a requirement. Without the statements in R4.3.1-R4.3.3, R4.3 is simply a phrase. Sub-Sub-Requirements R4.3.1 through R4.3.3 should be bullets under R4.3, with the language in R4.3 modified so that it becomes the requirement to conduct contingency analyses that address the three resulting bullets. R4.3.2 it is not clear what is required to be modeled. Typically a generator may have 10 or more protective relays. Is the intent to model all relay protection? The existing commercial programs do not have sufficient models or capacity to do that for all generators in the system. R4.5 We disagree with the requirement to explain why remaining Extreme Contingencies would produce less severe System results than the ones selected for study. The first part of the requirement requires identification of events that produce more severe System impacts. The reason the others were not selected is because they were less severe or non-credible. In any case, theoretically, there can always be a more severe Extreme Contingency than the one selected for study. For example, if the Extreme Contingency studied were simultaneous loss of 3 transmission lines with failure of redundant RAS, then simultaneous loss of 4 lines with failure of 2 sets of redundant RAS would be more severe. Listing all possible extreme events could result in a limitless list.
Response: R4.3: The SDT disagrees as these are mandatory elements of the Contingency analyses. Bullets are only used to identify the possible, but not all inclusive, elements of a menu. However, Requirement R4, part 4.3 has been modified to read more like a requirement as shown below. **4.3** Contingency analyses shall be performed and: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of all relay protection. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. R4.5: Several industry commenters have indicated that an explanation of "why the remaining Contingencies would produce less severe System performance" should be deleted since the Contingencies selected are those that produce more severe System performance. The SDT agrees and has deleted the requirement for an "explanation of why the remaining Contingencies would produce less severe System results". **4.5** Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list of those events to be evaluated for System performance in Requirement R4, part 4.2 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. If the analysis concludes there are cascading outages caused by the occurrence of extreme events, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences of the event(s) shall be conducted.	

Organization	Question 4 Comment
Independent Electricity System Operator	. Same comments as in R3, above, except our proposed wording on R4 will read:R4. The Stability analyses of the Near-Term Planning Assessment as stipulated in R2.4.2 shall be performed as follows:. since there are no detailed requirements stipulated for Stability analysis portion for the Long-Term Planning Assessment. However, the main requirement contains a condition for performing the Contingency analyses listed in Table 1. First of all, there are no VSLs for failing to meet this condition. Secondly, this duplicates with some of the subrequirements, e.g. R4.4, R4.5. Suggest to remove this condition from the main requirement. If the main requirement is to be revised in a similar fashion as suggested for R3, then this will become a non-issue. 2. Similar to R3, we agree with the VRF, Time Horizon and Measure for R4. However, we do have the same difficulty with the VSL based on our comments on the convoluted nature of the requirement as indicated above, especially on the Moderate VSL for The Transmission Planner or Planning Coordinator did not base its studies on computer simulations using models utilizing data provided in Requirement R1.
Response: R4: The SDT does not see any need for Requirement R4 to reference back to Requirement R2, part 2.4. No change made. R4 VSL: (1) The VSL for Requirement R4 does cover failing to perform the Contingency analysis in Table 1. Depending on how many Contingency categories are not addressed, the violation could be moderate, high, or severe. No change made. R4 VSL: (2) Requirement R4 provides the general requirement to perform the Contingency analysis in Table 1. The parts like Requirement R4, part 4.4 provide more details on what must be run. There is no duplication. No change made. R4.5: The SDT believes that Requirement R4, part 4.5 is a necessary part. No change made. R4 VSL: The SDT disagrees with this idea. No change made.	
Kansas City Power & Light	R4.3 requires very labor intensive and detailed studies to be conducted; there are concerns about being able to accomplish the required studies within the 24 month implementation period; additionally, while there may be some reliability benefit to requiring these studies have the costs of this reliability increase been studied?; an alternative could be some sort of phased implementation (x% completed by 24months, etc.) R4.3.3 to what degree is generator relaying factored into the model/study?
Response: R4.3: The SDT believes that 24 months is sufficient to perform the additional studies. No change made. R4.3.3: Generator relaying is not a part of Requirement R4, part 4.3.3.	
ReliabilityFirst Corporation	R4.3.2 – Requires simulating generator voltage ride through capability. This may require modeling generator protection schemes to existing Dynamic models. This falls under which again falls under Section 1600 of NERC Rules of Procedure.
Response: R4.3.2: The intent of this requirement is to include in the assessment how voltage ride-through capability is analyzed in your studies. It does not require modeling of generator protection schemes. There is a reliability standard (PRC-024) under development which will require Generator Owners to provide information	

Organization	Question 4 Comment
about the low voltage ride through capability of their generators based on relay settings. If complete information on the ride-through capability is not available, then you should document your assumptions regarding voltage ride-through capability for the assessment. The SDT has changed the wording of Requirement R4, part 4.3.2 to clarify this. **4.3.2** Trip generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.	

5. Requirement R5 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: In response to industry comments, the SDT has deleted the word 'proxy' in favor of the terminology 'criteria or methodology' in Requirement R5 (now Requirement R6).

R6. Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Organization	Question 5 Comment
Dominion - Electric Transmission Tucson Electric Power Company	Use of Proxies: There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.
Hydro-Québec TransEnergie (HQT)	There is no requirement that the Planning Coordinator must use the same proxies as the Transmission Planner. Differences in proxy assumptions may lead to different study results. R5 needs to be modified to require coordination of proxies between Planning Coordinators and Transmission Planners.
Response: Criteria or methodologies will be fleshed out in peer review. No change made.	
OPUC	MRO NSRS proposes specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. MRO NSRS suggests this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.
Response: The SDT has revised the requirement language to provide greater clarity as to the intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Bonneville Power Administration	There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies. M5 doesn't make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL.
Response: Criteria or methodologies will be fleshed out in peer review. The SDT has changed the language of Requirement R6 (formerly Requirement R5). **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement is in line with accepted Guidelines. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	
MRO MRO NERC Standards Review Subcommittee	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R5.
PacifiCorp	None - no concerns identified by the TWG
JEA	PEF does not presently have any concerns with R5.
Central Maine Power Company	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, due to other responses, some changes have been made. Please see the summary response.	
SRP	In R5 the term “proxy” needs to be defined. In addition, an example of a proxy should be given.
Gainesville Regional Utilities	R5:Guidelines for identifying proxies for unstable conditions would be helpful.
Progress Energy Florida, Inc.	The term proxy is unclear. Please provide an example or an explanation of proxy. If this is related to Note “i” in Table 1, it should be so stated. If it is related to assumptions or criteria, please state so.
Xcel Energy	Please clearify "Proxies"
Mississippi Delta Energy Agency	The term proxy is unclear. Please provide an example or an explanation of proxy. Perhaps a different term, such as metric, may better describe this requirement to more people.
Tenaska, Inc.	In R5, what is meant by the term “any proxies”? Please clarify. This comment also pertains to this terms use in the VSL as well.

Organization	Question 5 Comment
Manitoba Hydro	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Is a “proxy” a “criteria”?
National Grid	Comments: The meaning of the word “proxies” in this context seems uncommon making the requirement unclear. Perhaps “proxies” should be replaced with “criteria” or “criteria or proxies”.
Northern Indiana Public Service Company	What is a proxy as related to transmission planning? The drafting team should not introduce "non-standard" terms in a Standard document.
San Diego Gas and Electric Co	R5. For clarification, please list examples of "proxies" that might be used.
Minnesota Power	an example of proxy may be helpful, not all entities use proxies.
ISO New England, Inc. Western Area Power Administration American Electric Power Great River Energy New York Independent System Operator Modesto Irrigation District Louisiana Energy and Power Authority City Utilities of Springfield, MO Duke Energy New Brunswick System Operator MidAmerican Energy Company	The term proxy is unclear. Please provide an example or an explanation of proxy.
California ISO NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	The term “proxies” is somewhat confusing; recommend the use of “assumptions” if that is an acceptable substitute.
Independent Electricity System	On page 13 under Section R5, can the term “proxies” be defined and clarified, and examples given, in this context ?

Organization	Question 5 Comment
Operator Northeast Power Coordinating Council	
Kansas City Power & Light	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
IRC Standards Review Committee	We recommend using an alternate term for proxies such as criteria, guidelines, etc. to clarify what is meant.
Pepco Holdings, Inc. - Affiliates	We recommend that the word “proxies” be changed to “criteria”.
Transmission Planning	5. Requirement R5 Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.Comments:A: An example should be added for proxy use.
TVA System Planning	It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
United Illuminating	Please clarify how the term “Proxies” is used in this requirement.
PPL Energy Plus	Please define the term "proxies".
CPS Energy	Comments: It is unclear as to what is meant by the term “proxy used in the analysis” as it is used in this requirement. Does this mean Planning Coordinator established practices, thresholds, or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
SERC Engineering Committee	In the VSL associated with R5, we believe that failure to define and document one of the proxies should be a moderate VSL,

Organization	Question 5 Comment
Reliability Review Subcommittee (RRS)	failure to define and document two proxies should me a high VSL, while failure to define and document three proxies should be a severe VSL. Otherwise failing to document only one proxy would result in a severe VSL. The word "proxies" in this context is confusing and subject to various interpretations. Recommend changing the word "proxies" to "criteria. There is no requirement that the Planning Coordinator (PC) must use the same proxies as the Transmission Planner (TP). Since differences in proxy assumptions may lead to different study results, R5 should be revised to require the PC and TP to coordinate the use of proxies.

Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.

The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent.

> **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

The SDT does not see the need for a requirement to coordinate the use of proxies. No change made.

Organization	Question 5 Comment
FirstEnergy Corp	The determination of a failure to document a single proxy should not be categorized as "severe".

Response: The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.

Organization	Question 5 Comment
Southern Company	"Proxies" is not defined. We take "proxy" to mean a procedure used to model system response that is outside the capability of system modeling tools used in the analysis. For example, a powerflow model might not be able to model cascading events with built-in capabilities. As a proxy, the engineer would run follow-up studies that would mimic expected system response. Please define the term "proxy".
SMUD	It is unclear as to what is meant by the term "proxy used in the analysis" used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Platte River Power Authority	We propose specifying that the proxy documentation be included in the Planning Assessment and add the rationale for the proxy. We suggest this text: "Each Transmission Planner and Planning Coordinator shall document within the Planning Assessment any proxies used in the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding. The documentation will consist of the definition of each proxy used and the rationale for the proxies.

Organization	Question 5 Comment
Turlock Irrigation District	Comments: It is unclear as to what is meant by the term “proxy used in the analysis” used in this requirement. Does this mean Planning Coordinator established practices, thresholds or guidelines used to gauge when simulations suggest an event such as cascading outages occurs? If so the language should state: R5. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, when established practices, thresholds or guidelines identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.
Response: The SDT agrees with this comment and has changed the Requirement language to provide clarity as to intent. **R6.** Each Transmission Planner and Planning Coordinator shall define and document, within its Planning Assessment, any criteria or methodology used in its analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.	
Deseret Generation & Transmission	Please provide a definition of "cascading outages" since the FERC and NERC removed their approval of the definition. Or use the definition of "cascading" found in the NERC Glossary of Terms. This term is also used in R3.5, R4.5, and Table 1.a. without any definition provided. NOTE: On December 27,2007, the Federal Energy Regulatory Commission remanded the definition of” Cascading Outage” to NERC. On February 12, 2008, the NERC Board of Trustees withdrew its November 1, 2006 approval of that definition, without prejudice to the ongoing work of the FACstandards drafting team and the revised standards that are developed through the standardsdevelopment process. Therefore, the definition is no longer in effect. Please provide a definition of "voltage instability" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided. Please provide a definition of "uncontrolled islanding" since the NERC Glossary of Terms does not provide one. This term is also used in Table 1.a. without any definition provided.
Response: The SDT declines to provide definitions for the indicated terms.	
Puget Sound Energy, Inc.	Data Retention: The 5th bullet should refer to “proxies” instead of “studies”.
Response: The SDT disagrees with your statement as the studies will reveal the Proxies (now criteria or methodology) used in the Planning Assessment. No change made.	
E.ON U.S.	M5 doesn’t make any sense. Need to revise this Measure so that it fits the Requirement R5. Also need to revise the Data Retention discussion in Section 1.4 to align with R5. In the VSL associated with R5, we believe that failure to define and document the proxies should be a moderate VSL.
Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made. The SDT does not agree and believes that the Data Retention for this Requirement should be and is identical to the other Requirements. No change made. The SDT appreciates your comment on the level of severity for this Requirement but still believes this is the appropriate level to apply. No change made.	

<table>
<tr><th>Organization</th><th>Question 5 Comment</th></tr>
<tr><td>Entergy Services, Inc</td><td>Under R5, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R5 only says “Long-term Planning”. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: “Near-Term and Long-Term Transmission Planning”.</td></tr>
<tr><td>ITC Holdings</td><td>Under R5, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R5 only says “Long-term Planning”. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: “Near-Term and Long-Term Transmission Planning”.</td></tr>
<tr><td colspan="2">Response: The Time Horizon term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

• Long-term Planning — a planning horizon of one year or longer.
• Operations Planning — operating and resource plans from day-ahead up to and including seasonal.
• Same-day Operations — routine actions required within the timeframe of a day, but not real-time.
• Real-time Operations — actions required within one hour or less to preserve the reliability of the bulk electric system.
Operations Assessment — follow-up evaluations and reporting of real time operations.</td></tr>
<tr><td>Idaho Power</td><td>M5 doesn’t make any sense. Need to revise this Measure so that it fits the Requirement R5.

Also need to revise the Data Retention discussion in Section 1.4 to align with R5.</td></tr>
<tr><td colspan="2">Response: The SDT does not agree and believes that the Measure appropriately addresses Requirement R6 (formerly Requirement R5). No change made.</td></tr>
</table>

6. Requirement R6 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet the requirements of the TPL standard and to the Corrective Action Plan developed as part of the Planning Assessment. The intent of this requirement is to clarify that while the responsibilities for the TPL requirements are for both the Transmission Planner and Planning Coordinator, the individual tasks may be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. The SDT has made changes for clarity.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.

Organization	Question 6 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. Central Maine Power Company	We do not feel that this requirement belongs in this standard and it should be deleted. The standard defines requirements for the assessment not who does what.
Response: The intent of this requirement is to clarify that TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. This requirement does not preclude any single entity from performing all the study work required to support an assessment. No change made.	
MRO NERC Standards Review Subcommittee	MRO NSRS is not clear if: 1) Each Transmission Planner is to meet all the requirements including doing all the studies and all Planning coordinators are to meet the requirements including doing all the studies.Or 2) If the Transmission Planner and Planning Coordinator are to work as a team to meet all the requirements including doing all the studies. Either one of them could do various parts of the required studies. For example, maybe the PC could do the stability part so all TP's would not necessarily have to buy that software if they did not need it for other planning purposes.In the first read of this standard, it appears that the intention was number 1, which sounds awfully duplicative. But then take a look at Requirement 6. R6. Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment. [Violation Risk Factor: Low] [Time Horizon: Long-term Planning]After reading R6, it appears that number 2 was intended. Perhaps R6 should be the very first requirement in the standard. The MRO NSRS requests that the NERC SDT clarify the responsibility of the requirements of this standard.

Organization	Question 6 Comment
Response: The requirement specifies that individual and joint responsibilities for performing the required studies be identified. Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
SERC Engineering Committee Reliability Review Subcommittee (RRS)	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. How do the Corrective Action Plans get resolved between these entities if there is no agreement on the study results??Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies. In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The proposed changes to the VSLs do not conform to Guideline 3 of the FERC VSL order. No change made to the VSL. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R6.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R6.
American Transmission Company	We agree with the revisions to R6.
Independent Electricity System Operator	We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: Thank you for your response. However, please see changes indicated in the summary due to other industry comments.	
TVA System Planning	In the VSL associated with R6, we believe that failure to determine and identify one responsibility should be a moderate VSL, failure to determine and identify two responsibilities should me a high VSL, while failure to determine and identify three responsibilities should be a severe VSL. Otherwise failing to document only one responsibility would result in a severe VSL.
Response: The proposed changes to the VSL do not conform to Guideline 3 of the FERC VSL order. No change made	

Organization	Question 6 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Please clarify that the phrase “individual and joint responsibilities” applies to entities (e.g., the TPs and PCs) and not specific individuals.R6 Please clarify if this requirement is intended for cases where a TP is not a PC and therefore is working “under” a PC? Or if this is intended to apply across neighboring PC’s?
FMPA	Please clarify that the phrase “individual and joint responsibilities” applies to entities (e.g., the TPs and PCs) and not specific individuals.
Response: Thank you for pointing out a potential for misinterpretation of the intent of the requirement. The SDT has modified the language**.** **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Xcel Energy	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.
Ameren	In absence of these agreements, it is assumed that both Transmission Planners and Planning Coordinators would be responsible for performing the studies. It is not clear how the Corrective Action Plans get resolved between these entities if there is no agreement on the study results.
Duke Energy	Requirements R1, R2, R3, R4 and R5 should all be revised to include a reference to R6 regarding the determination of individual and joint responsibilities for performing the required studies.
Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis to meet all the requirements of the TPL. This includes the corrective action plan developed as part of the assessment. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment.	
Midwest ISO	A) Under R6, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R6 only says “Long-term Planning”. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: “Near-Term and Long-Term Transmission Planning”.
Minnesota Power	Under R6, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R6 only says “Long-term Planning”. By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: “Near-Term and Long-Term Transmission Planning”.
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time	

Organization	Question 6 Comment
frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
Brazos Electric Cooperative	is there any other way to identify responsibilities between the parties than having an agreement? R6 seems to indicate an agreement of some sort must be in place. if that is the case then it could simply say an agreement must be in place.
Response: The requirement has been clarified in response to others' comments. The SDT did not want to imply that a separate agreement would be required for the purposes of the assessment. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
ITC Holdings	Comments: Should this requirement state that ?The Transmission Planner in conjunction with their Planning Coordinator shall determine and identify individual and joint responsibilities for performing the required studies for the Planning Assessment.
Response: The SDT has modified the language. **R7**. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity's individual and joint responsibilities for performing the required studies for the Planning Assessment.	
LADWP	R6: Does this requirement requires authors of the planning assessment report should be identified? If so, can we use plain English like "The authors of the Planning Assessment report shall be identified". If not, please explain what this requirement is all about.
Kansas City Power & Light	Why is this needed if both entities must comply with the standard?At a minimum the requirement should include language to state that the one party must provide to the other with enough notice to comply with a required study if there is a shift or assignment of a responsibility.

<table>
<tr><th>Organization</th><th>Question 6 Comment</th></tr>
<tr><td colspan="2">Response: Requirement R6 (now Requirement R7) is an overarching requirement that applies to the entire set of analysis required to meet all the requirements of the TPL and to the corrective action plan developed as part of the assessment. The intent of this requirement is to clarify TPL requirements can be met through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. Coordinating and/or joint analysis does not alleviate the responsibility that all entities need to comply with the standard requirements.

R7. Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment.</td></tr>
<tr><td>Orlando Utilities Commission</td><td>R6: Is this requirement intended for cases where the TP is not also their PC, or is this between adjacent PC’s?</td></tr>
<tr><td colspan="2">Response: The intent of this requirement is to clarify TPL requirements can be meet through joint or shared analysis. Industry feedback indicates that it is important to minimize duplicative studies to the greatest extent possible. The requirement has been clarified in response to others’ comments.

R7. Each Planning Coordinator, in conjunction with each of itsTransmission Planners, shall determine and identify each entity’s individual and joint responsibilities for performing the required studies for the Planning Assessment.</td></tr>
</table>

7. Requirement R7 – Please provide any specific comments on the requirement text, VRF, Time Horizon, measure associated with the requirement, data retention associated with the requirement, and/or the VSL associated with the requirement.

Summary Consideration: Many commenters feel that the reference to FERC Order 890 is inappropriate, but most do not argue against the importance of sharing Planning Assessment information. There was also concern about the meaning of the phrase "coordinating of analysis of these results", and what was specifically required. The SDT believes sharing of information, understanding the impact on/from neighboring areas, peer review/feedback, and wide area assessment are important to effective Transmission planning. As a result of the comments several revisions have been made to TPL-001-1.

Revisions to Requirement R3, part R3.4 and Requirement R4, part 4.4 will clarify the expectation that Transmission Planner's and Planning Coordinator's analyze Table 1 events outside their System for reliability impacts to understand neighboring System impacts. The revised TPL-001-1 Requirement R8 (formerly Requirement R7) will ensure appropriate information is exchanged between Transmission Planner's and Planning Coordinator's for sharing of information, review, and coordination of plans in conformance with Order 693, paragraph 1755 and 1756 expectations by requiring distribution of Planning Assessments to neighboring Transmission Planners and Planning Coordinators, as well as entities with a reliability-related need. The NERC Rules and Procedures and delegation agreements cover existing TPL-005-0 & TPL-006-0 assessment requirements for regional and inter-regional assessments allowing for retirement of these two standards. The aggregate effect of the above items will be an overlapping assessment of BES reliability from each Transmission Planner area up through each Interconnection.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

M8 Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Question 7 Comment
Northeast Power Coordinating Council United Illuminating Northeast Utilities ISO New England, Inc. National Grid Central Maine Power Company	This standard should not be reiterating FERC Order 890. We do not feel that this requirement belongs in this standard and it should be deleted.
SERC Engineering Committee Planning Standards Subcommittee	FERC Order 890:The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read “as described in FERC Order 890. If not, this should not be mentioned at all.
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Arizona Public Service Co Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc. NV Energy Southern California Edison Company San Diego Gas and Electric Co California ISO Tucson Electric Power Company	We believe that references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.

<table>
<tr><th>Organization</th><th>Question 7 Comment</th></tr>
<tr><td>NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)</td><td>In R7 the references to FERC Orders should not be included in requirements of standards. This comment also applies to M7.</td></tr>
<tr><td colspan="2"> Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted. R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. M8 Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8. </td></tr>
<tr><td>MRO NERC Standards Review Subcommittee</td><td>MRO NSRS proposes expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. MRO NSRS suggests this text: “Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.</td></tr>
<tr><td colspan="2"> Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. An additional sub-requirement has been added to require that if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. R8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. </td></tr>
<tr><td>SERC Engineering Committee Reliability Review Subcommittee (RRS)</td><td> The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read “as described in FERC Order 890. If not, this should not be mentioned at all. “ Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. Does this need to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators?? In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL. </td></tr>
</table>

Organization	Question 7 Comment
Response: The SDT agrees that the standard should not reference Order 890 and the reference has been deleted. The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment. The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	

R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Organization	Question 7 Comment
FirstEnergy Corp	We agree with the stated Requirement, Measure, VRF, Time-Horizon, Data Retention and VSL of requirement R7.
Progress Energy Florida, Inc.	PEF does not presently have any concerns with R7.
Response: Thank you for your response. However, please note the changes made to Requirement R7, Measure R7, and the Requirement R7 VSL (now Requirement R8) due to a majority of industry commenters indicating that some changes were needed.	
IRC Standards Review Committee	Is the PC expected to distribute the TP Planning Assessments as part of its coordination requirement?
Response: The term "coordinating analysis" has been deleted from the requirement and only distribution of assessments by the Transmission Planner and Planning Coordinator is required. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	

Organization	Question 7 Comment
TVA System Planning	In the VSL associated with R7, we believe that the PC failing to coordinate analysis should be a moderate VSL, the PC failing to distribute should be a high VSL, and failing to do both of these tasks should be a severe VSL.

Response: The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8 VSL	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The Transmission Planner or Planning Coordinator failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The Transmission Planner or Planning Coordinator failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Southern Company	We recommend the following wording for R7.Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Planning Coordinators and any functional entity who has indicated a reliability need. Each Planning Coordinator shall coordinate analysis of these results through an open and transparent peer review process such as described in FERC Order 890.

Response: The SDT agrees and, in addition, the scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results.

The VSL has been modified to reflect the changes to the requirement. The requirement no longer requires a coordinated analysis. The failure to distribute the results is a High VSL. Failure to respond to comments is a Severe VSL.

R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment

Organization	Question 7 Comment			
	its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.		Planners and Planning Coordinators, respectively in accordance with Requirement R8.	results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.
System Protection and Transmission Planning Department	The phrase "coordinating analysis of these results" seems to indicate potential second-guessing by other entities. We suggest "coordinating REVIEW of these results" may be clearer. The term "such as described in FERC Order 890" allows non-jurisdictional utilities to establish an appropriate process. This is good. However, we still have the same misgivings about the term "such as" used here.			
Manitoba Hydro	It is unclear as to what is meant by “coordinating analysis of these results”? Does this imply an obligation to conduct joint studies or just an obligation to distribute the assessment and respond to feedback? We suggest that the wording “such as described in FERC Order 890” be replaced with “such as may be required by a regulator in its PC/TP area”. The SDT is posing several other questions for industry consideration not related to the specific requirement questions above.			
Response: The SDT agrees that the term “coordinating analysis” is unclear and has modified Requirement R7 (now Requirement R8) to only require distribution of planning assessments. The reference to Order 890 is no longer necessary. However, the SDT does believe it is appropriate to require a response if a recipient of the Planning Assessment results provides documented comments on the results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.				
PPL Energy Plus	Please continue to mention relevant FERC Orders (such as 890) in the standards since the FERC orders are the source of many of the planning standards. Planners need to acknowledge, respect, and design processes and systems around the FERC rulings.			
MidAmerican Energy Company	MidAmerican commends the SDT for its hard work on this standard. MidAmerican recommends changing R7 by changing “FERC Order 890” to “FERC Order No. 890”.			
Response: The majority of commenters had an opposite opinion of referencing FERC Orders in NERC standards and the reference to Order 890 has been deleted.				
Florida Reliability Coordinating Council, Inc - Transmission Working Group	The requirement as written requires that the results of the assessment are shared on a post assessment basis between entities in a manner similar to the Attachment K process. Please clarify whether:-Is this intended to be the end results? Or does this require the inviting of entities in at the very beginning and facilitating their participation throughout the process? -Is it intended that the process described in order 890 become essentially a NERC Standard that every sentence must be met in the most literal of sense? Or is this referencing the order as a general guideline on what should be expected but not as a literal			

Organization	Question 7 Comment
	checkmark of the process? Consider adding a footnote or other clarifications that failure of others to participate in the process is not a non compliance by the entity inviting them to the process. Otherwise non-responsiveness of a neighboring PC who may not have reliability need to participate and whose participation is beyond the control of the PC that initiated the process could trigger non-compliance.
Entergy Services, Inc	This requirement is addressed through FERC Order No. 890 (9 principles of transmission planning).
Platte River Power Authority	R7. Delete this requirement as it is the responsibility of the Transmission Provider under FERC Order 890.
American Transmission Company	We propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to FERC Order 890 and peer review. We suggest this text: “Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, and distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
SMUD	Requirement R7 should end after the words '....who has indicated a reliability need'. R7:The requirement should not invoke another document for compliance. The words, ", coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890', should be deleted. This comment also applies to M7.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. Conforming changes have been made to Measure M7 (now M8). **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and	

Organization	Question 7 Comment
Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. **M8** Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient, date, and contents, or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and any functional entity who has indicated a reliability need and has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.	
Xcel Energy	Recommend deleting the portion of the requirement that states: "coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
LADWP	FERC 890 stands on its own, why should a planning standard refers to a FERC Order? Does this imply that if a FERC Order is not referenced in the planning standard, we can ignor the order?
Independent Electricity System Operator	1. We question the need to mention FERC 890. If this meant to be an example for the US entities, we suggest this to be put into a footnote with indication that it is an example for the US entities only.2. We agree with the requirement, the VRF, Time Horizon, Measure and VSLs.
Response: The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Ameren	Requirement R7 describes that the Planning Coordinator is to share Planning Assessments with adjacent Planning Coordinators. It is not clear whether this needs to be expanded for the Transmission Planners to share their Planning Assessments with the Planning Coordinators. The reference to FERC Order 890 as it is currently written makes it seem like a suggestion to follow Order 890. If Order 890 explicitly describes this process then the sentence should read "as described in FERC Order 890. If not, maybe this should not be mentioned at all.
Response: The scope of entities has been modified. Each Transmission Planner and Planning Coordinator shall distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Midwest ISO	A) Under R7, the Time Horizon of the TPL standards is intended for years one through 10; However the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10

Organization	Question 7 Comment
	and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning". B) The coordination of analysis of results through an open and transparent process is already a FERC requirement thus producing a double jeopardy for those entities that fall under the jurisdiction of FERC Order 890. We recommend striking the following language in the last sentence: ...coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. C) Under R7 only the Planning Coordinator is required to coordinate the distribution of Planning Assessment results among adjacent PCs and any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. Should the TP be added to this requirement? We propose the suggested language change: Each Transmission Planner and Planning Coordinator shall coordinate the distribution of Planning Assessment results among adjacent Transmission Planners and Planning Coordinators, respectfully, and to any functional entity who has indicated a reliability need, coordinating analysis of these results through an open and transparent peer review process such as described in FERC Order 890. D) Based on the comments above in (B) and (C), our suggested requirement language is as follows: Each Transmission Planner and Planning Coordinator shall coordinate analysis in support of assessments in accordance with applicable regulatory requirements. Each Planning Coordinator shall distribute its completed planning assessment results among adjacent Planning Coordinators and any functional entity who indicated in writing a reliability related need.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.
- **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.
- **Operations Assessment** — follow-up evaluations and reporting of real time operations.

The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the requirement has been modified. The standard now requires each Transmission Planner and Planning Coordinator to distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

Organization	Question 7 Comment
R8 Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
PJM	R7 needs to be broken into two parts. First establish the list of entities that need to get the assessment results. Second would be to coordinate the results as mentioned. Are the results mentioned in R7 different from the Planning Assessment?
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. The reference to "results" in Requirement R7 (now Requirement R8) is to the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Minnesota Power	Under R7, the Time Horizon of the TPL standards is intended for years one through 10; however, the Time Horizon shown in R7 only says "Long-term Planning". By definition of Long-Term Transmission Planning Horizon this covers years 6 through 10 and beyond. Suggestion to change the Time Horizon to read: "Near-Term and Long-Term Transmission Planning".
Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made. **Mitigation Time Horizon** The time horizons available for mitigating a violation to a requirement include the following: • **Long-term Planning** — a planning horizon of one year or longer. • **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal. • **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time. • **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system.	

Organization	Question 7 Comment
• **Operations Assessment** — follow-up evaluations and reporting of real time operations.	
MAPPCOR	Propose expanding the scope of entities to consider, limit it to those entities that indicate a reliability need for coordination, and eliminate the direct reference to Order 890. Suggest this text: “Each Planning Coordinator shall establish a list of adjacent Planning Coordinators and any functional entity who has indicated a reliability need, distribute its Planning Assessment results to the listed entities and consider comments on the assumptions and results through an open and transparent peer review process.
Response: The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. The reference to Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Orlando Utilities Commission	The term “results of the assessment”, is this is the final end result that is shared and analyzed? A requirement should not reference an order or another non NERC document. All the requirements and measures for performance should be covered in the standard or through reference to another NERC approved standard. The language used in other standards would be more appropriate and directly auditable. Require that the PC/TP to share assessment and support material with those requesting entities and respond to any of their specific comments. This will insure openness and transparency in a manner and can be directly audited.
Response: The reference to “coordinating analysis” and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.	
Turlock Irrigation District	In light of the fact that FERC has determined not to apply the Order No. 890 transmission planning processes requirement to non-public utilities, TID expresses concern over the reference to Order No. 890 in R7. TID recommends that this reference be replaced with a more direct instruction that details what exactly is meant by the requirement of “an open and transparent peer review process. R7 makes reference to the peer review process laid out in FERC Order No. 890. This reference to Order No. 890 is duplicative and vague and must be clarified. The peer review process set forth in Attachment K of Order No. 890, lays out nine different principles (Coordination, Openness, Transparency, Information Exchange, Comparability, Dispute Resolution,

Organization	Question 7 Comment
	Regional Participation, Economic Planning Studies, and Cost Allocation for New Projects). Most of these principles are inapplicable when placed in the context of NERC Reliability Standards. Subjecting NERC members to all of these vague and broad principles without specific guidance as to their application would be a significant burden. TID proposes that the reference to Order No. 890 be removed from R7 and replaced with a provision that expressly details the principles of openness and transparency that are contemplated in R7. Such an express provision would bring clarity to the requirement so that entities subject to R7 would know exactly what they are expected to do to comply with the requirements of R7. As it is now written, the broad reference to Order No. 890 is vague and confusing.TID is also concerned with the fact that the Violation Severity Levels for R7 now appear to run from High to Severe, with the potential of significant penalties being assessed on noncompliant entities. The High and Severe Violation Severity Levels for TLP-001-1 R7 are inappropriate given the already vague and conflicting guidance of R7, especially as R7 merely duplicates the Order No. 890 requirements. Once the reference to Order No. 890 is replaced with a provision that expressly provides specific guidance as to what is meant by the "open and transparent peer review process," the appropriate Violation Severity Level for R7 would be Low to Moderate.

Response: The reference to "coordinating analysis" and Order 890 created confusion regarding process requirements and the reference has been deleted. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. In addition, if a recipient of the Planning Assessment results provides documented comments on the results, the respective Transmission Planner or Planning Coordinator shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. This simplifies the process while achieving appropriate involvement of affected entities.

The VSL's have been modified based on the clarified Requirement R7 (now Requirement R8) for distribution of Planning Assessments, the importance of sharing planning information and being responsive to neighboring entities reliability related concerns.

> **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
>
> **R8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

R8 VSL	The responsible entity failed to distribute the results of its Planning Assessment to any one of its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	N/A	The responsible entity failed to distribute the results of its Planning Assessment to its adjacent Transmission Planners and Planning Coordinators, respectively in accordance with Requirement R8.	The responsible entity failed to provide a documented response to a recipient of the Planning Assessment results who provided documented comments on the results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

New York Independent System	The Standards Drafting Team should clarify the standard as to whether the PC will be expected to distribute the TP Planning

Organization	Question 7 Comment
Operator	Assessments as part of its coordination requirement?
Response: The language has been clarified as to the responsibility of each Transmission Planner and Planning Coordinator. The standard now requires each Transmission Planner and Planning Coordinator distribute Planning Assessment results to adjacent Transmission Planners and Planning Coordinators, respectively; and to any functional entity that indicates a reliability-related need for the Planning Assessment results. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	
Kansas City Power & Light	Recommend deleting the portion of the requirement that states: “coordinating analysis of these results through an open and transparent review process such as described in FERC Order 890.
Response: The reference to “coordinating analysis” and Order 890 created confusion regarding process requirements and the reference has been deleted. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.	

8. The SDT changed several definitions in response to industry comments to the second posting. Do you agree with these changes? If not, please clearly indicate which definition you disagree with and provide specific comments.

Summary Consideration: Many of the responders suggested that several of the definitions either be revised or deleted. As a result, the definitions for Supplemental Load Loss, Load Reduction, Planning Events and Extreme Events have been deleted and the definitions for Consequential Load Loss, Non-Consequential Load Loss and Year One have been revised.

In association with the changes in definitions, the SDT has also revised note 'b' and added note 'i' in the header to Table 1.

There were several requests to include comment on Under-frequency (UFLS) and Under-voltage load (UVLS) shedding. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled Load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. As a result, no change was made.

There were some suggestions to include definitions and distinction between 'planned' and 'proposed'. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the Standard from delving into the distinction. As a result, no change was made.

There were a couple of suggestions relative to adding back the examples of applications of Bus-tie Breakers or otherwise changing the definition. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although the examples were true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. As a result, no change was made.

There was a suggestion to change the reference to 'Horizon'. "Horizon" is not something new and the SDT does not agree with changing it. As a result, no was change made.

There were a couple of requests to include new definitions for "cascading outages", "voltage instability", and "uncontrolled islanding". The SDT did not see a reason to define these terms in TPL-001-1. The requesters were invited to draft a SAR if they wanted to pursue having these terms defined. As a result, no change was made.

The following changes were made to definitions as a result of industry comments:

Consequential Load Loss: All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault.

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

Year One: The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note 'i': The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Revise the Load Reduction and Non-Consequential Load Loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)For Drafting Team consideration: What types of non-interruptible load loss would be considered non-consequential load loss--manual load shedding for example? With this in mind, can the definition be simplified, maybe to read: Non-Consequential Load Loss: Operator action taken to deliberately remove load from service in response to adverse system conditions.
Response: The SDT has deleted the Load Reduction definition. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
SERC Engineering Committee Planning Standards Subcommittee	No	Definitions: Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Load Reduction Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Bus tie breaker A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1.		

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where Bus-tie Breakers were used between ring buses, etc. No change made.		
Modesto Irrigation District	No	On page 2 under "Definitions of Terms Used in Standard", the red-lined out example used to clarify the definition of "Non-Consequential Load Loss" seems valuable to me, and I think they should not remove it but leave it in.
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Xcel Energy Western Area Power Administration Southern California Edison Company San Diego Gas and Electric Co Idaho Power California ISO	No	Clarification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?
Arizona Public Service Co	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column has a No entry, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?

Organization	Yes or No	Question 8 Comment
Pacific Gas and Electric Co,	No	Claification is needed on the use of UVLS. Is it acceptable or not? We understand from the discussion in the webinar that in the proposed TPL-001-1, Table 1, if there is a “no” in the column for allowable load loss, you are still allowed to have UVLS set up to drop the load, but cannot plan on meeting the standard with the load shedding. Therefore, if the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation, given that you can lose the load but cannot plan on it? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. What about the treatment of Supplemental Load Loss or UFLS?
Puget Sound Energy, Inc.	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS?Provide clear explanations of the load definitions.
NV Energy	No	Claification is needed on the use of UVLS. Is it acceptable or not. Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? We are also wondering how loads that have interruptible rates should be handled.
LADWP	No	UVLS should be an allowed mitigation for multiple contingencies, P3 and above. UVLS is an effective measure against voltage collapse, a system condition that if not mitigated in a timely fashion could lead to cascading events. Saqme with UFLS.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Tucson Electric Power Company	No	Claification is needed on the use of UVLS. Is it acceptable or not? Typically UVLS relays are modeled in the study. Not allowing any load shedding as a result of UVLS relays could result in very costly fixes for a very small amount of remote load. If the Non-Consequential Load Loss Allowed column is No, is load disconnecetd from the system by UVLS a violation? What about Supplemental Load Loss or UFLS? Year One The use of calendar year is confusing. When does the 12-18 month window begin? We suggest “The year 18 months beyond the present month.
Response: UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The definition of Year One has been clarified. **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that		

Organization	Yes or No	Question 8 Comment
begins 12-18 months from the end of the current calendar year.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. MRO NSRS suggests text of: Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. MRO NSRS suggests text of: Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. MRO NSRS suggests text of: Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-Frequency Load Shedding programs, Over-Frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. MRO NSRS suggests text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. MRO NSRS suggests text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. MRO NSRS suggests text of: Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year. MRO NSRS would like to delete the definition of “Year One”. This is already being done and adding a planning window opens entities to noncompliance for conditions i.e. Model building outside of entities control.

Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required.

The proposed change to expand Protection System operation to include abnormal operating conditions is too vague and is too broad. In addition it would create an overlap with the definition of Non-Consequential Load because Protection Systems used to protect abnormal operating conditions would include Special Protection System which could be used to trip Non-Consequential Load. No change made.

The SDT has deleted the Load Reduction definition.

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the

Organization	Yes or No	Question 8 Comment
acceptability of the tools to be used for any Corrective Action Plan. No change made. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for Planning Events has been deleted. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	There is a need to add definitions to discriminate between planned and proposed projects. We propose the following definitions: Planned Facilities: Facilities that address the near-term deficiencies and have been approved with a financial commitment. Proposed Facilities: Facilities that address long-term deficiencies for which no commitment is required today since they may change based on future evaluation. We propose the following definitions for events: Planning Events: Events which are listed as Planning in Table 1 in Standard TPL-001-1. Extreme Events: Events which are listed as Extreme in Table 1 in Standard TPL-001-1. Bus-tie Breaker definition still seems somewhat generic and the use of 'configurations' causes uncertainty. We propose the following definition: Bus-tie Breaker: A circuit breaker whose intended purpose is to connect two individual substation buses. The definition of Supplemental Load Loss includes the phrase, "by end-user equipment", which could be understood to mean there are devices at the end-user location that remove this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. We propose the following definition: Supplemental Load Loss: End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event. Load Reduction: A decrease in the amount of connected Load caused by lower voltage conditions following a Planning or Extreme Event.
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.		

Organization	Yes or No	Question 8 Comment
The definition for planning events has been deleted. The definition for extreme events has been deleted. The definition as proposed by SERC for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The definition for Supplemental Load Loss has been deleted. The definition for Load Reduction has been deleted.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. “Bus tie breaker “ A statement in the previous version which listed examples was removed from this version of the definition. The statement was helpful and should be re-inserted. The statement was: “Substation configurations such as ring bus, breaker and a half, or double-bus double-breaker do not use bus tie breakers. “Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Consequential Load Loss - Is an SPS to trip load qualify as a planned protection system”? Load Reduction - Is this automatic as in a load response or is it operator initiated as in changes to transformer LTC? How would Supplemental Load Loss be included in the stability analysis? Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. “Where would interruptible load be included in these definitions” Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. “Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be

Organization	Yes or No	Question 8 Comment
		included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event." SERC RRS suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: ?Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers?. SERC Members believe that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”.

Response: The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘i’ in the header to Table 1.

Header note ‘b’: Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0.

Header note ‘i’: The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made.

An SPS does not qualify as a planned Protection System because it is not being used “to isolate the fault”, which is a condition of the statement. No change made.

The definition for Load Reduction has been deleted.

Interruptible load is either Consequential Load or Non-Consequential Load which is permitted to be lost for specific events and conditions defined in Table 1. No

Organization	Yes or No	Question 8 Comment
change made. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. The definition for Supplemental Load Loss has been deleted. Bus-tie Breaker has been capitalized in the Table. The definition for Load Reduction has been deleted. The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn't universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made. The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loop holes. The definition for Year One has been revised to add clarity. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
FirstEnergy Corp	No	A. Supplemental Load Loss: We disagree with newly proposed definition for "Supplemental Load Loss" which is introduced to address some stakeholders concerns related to a Load's response to transient conditions. Table 1 note "b" causes confusion indicating that Supplemental Load Loss is an acceptable consequence of a Planning Event or an Extreme Event but then goes on to say that Supplemental Load Loss can not be relied upon to meet steady state performance requirements. This seems to imply that it is permissible to use Supplemental Load Loss for stability analysis. It is not logical to allow its use in one time frame but not the other. The inclusion of the Supplemental Load Loss definition enters into a power quality issue at the end-user delivery point which is not the focus of the TPL-001-1 standard. FE suggests that this definition be removed. B. Load Reduction: The new proposed definition of "Load Reduction" while technically written correctly may not align with its common use throughout industry. Load Reduction is often thought of as an operator initiated response, rather than a natural system response to a contingency event. If the definition remains, the SDT should consider striking the text "following a Planning or Extreme Event" so that the definition can more generally apply to other areas of the standards if needed. However, as stated in question 9, we believe Load Reduction was inadvertently omitted in note "b" of the Table 1. If so, we would have similar concerns with the occasional use of Load Reduction in that it would be allowed in stability and excluded in steady-state FE suggests that this definition be removed.The "Load Reduction" definitional term brings into question what is an acceptable steady-state load model within the TPL-001-1 standard. The standard provides some prescriptive language in requirement R2.4.1 regarding dynamic stability load models but is silent on steady-state load modeling. Most transmission planners use a conservative approach of simulating constant power loads in the steady-state environment and therefore the "Load Reduction" definition would not apply. However, if a constant impedance load

Organization	Yes or No	Question 8 Comment
		model were used, Load Reduction would be reflected and less conservative outcomes would result. At a minimum, the standard should require the transmission planner to document its load modeling assumptions for steady-state simulations. [See above comment on Question 2 regarding a proposed new R2.1.1 requirement] C. Year One: We continue to oppose the Year One definition developed by the SDT. In our Draft 2 comments, FirstEnergy proposed a Year One definition of "The planning year that begins with the upcoming annual period under study". During the last comment period we indicated:"We believe the attempt to try and delineate between the near-term planning horizon and operational planning horizon is not needed within the TPL standard and that the near-term period should account for the upcoming annual study periods. If not revised, the need for two near-term studies on an annual basis is overly burdensome as many transmission planning organizations perform upcoming annual seasonal assessments for seasonal peak (summer/winter) periods. Requiring an additional two studies near-term does not provide significant benefit. Further reasoning for making the change is the allowance of operating procedures as part of Corrective Action plans. Operating procedures can easily be developed and implemented to mitigate projected performance violations prior to an upcoming seasonal period." The SDT's response from the Draft 2 comment period indicated "The standard does not require that studies are duplicated. If an operating study can be used to demonstrate an assessment for planning purposes, then the operating study would be sufficient."Since "Year One" is defined as "...a planning window that begins 12-18 months from the current calendar year" we would appreciate the SDT reconciling their Draft 2 response to the Year One definition and confirm whether or not it intends that a study of the next occurring seasonal peak period would suffice for meeting one of the current year Near-Term studies as required in requirement R2.1.1.A secondary concern with the Year One definition is its reference to the Transmission Planner with no mention of the Planning Coordinator. D. Planning Assessment: We suggest that the team consider an enhancement to the definition of "Planning Assessment". When read independently within the NERC Glossary of Terms a lay person should have a better understanding of the transmission Planning Assessment and it should set the foundational understanding that a Planning Assessment is not equivalent to a single study but rather a collection of studies. Additionally, the definition should more explicitly apply to the TPL-001-1 intended purpose. We propose a new definition based largely on the verbiage in requirement R2. "Planning Assessment: An annual documented evaluation of future Transmission System performance predicted over a minimum 10-year period, based on new or previously completed simulation studies and the Corrective Action Plans needed to satisfy steady-state, stability and short circuit performance requirements." E. Planning Event: We propose that the definition of "Planning Event" more explicitly apply to the TPL-001-1 standard and read as follows: "Planning Event: A contingency condition evaluated for its steady-state and stability impacts on the BES transmission System, requiring Corrective Action plans to remedy identified deficiencies" F. Consequential Load Loss: We suggest that the definition be revised to more closely align with the text stated in requirement R3.3.1. The proposed definition would read "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the removal of all elements that the Protection System and other automatic controls are expected to disconnect for a transmission System Contingency without operator intervention." If our proposed new definition is not acceptable, we suggest that the word "automatically" be added between "being removed" and replace "a planned" with "as designed".

Organization	Yes or No	Question 8 Comment
Response: The definition of Supplemental Load Loss has been deleted from the revised standard. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Load Reduction has been deleted. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. The SDT does not agree with combining the types of studies in the definition of Planning Assessment. No change made. The definition for planning event has been deleted. The definition of Consequential Load Loss has been revised however the SDT did not believe that it was necessary to insert 'automatically' in the definition. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
IRC Standards Review Committee New York Independent System Operator	No	The Year One definition is confusing. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Is that January 1 of the current calendar year? Further, when does year 2, year 3, etc? start? Is this definition only applicable to the TP?
Progress Energy Carolina (PEC)	No	In this definition: "Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year" recommend that the '12-18 months' specification be removed. It is confusing.
E.ON U.S.	No	Year One: The calendar year contains 12 months. As written, Year One could start as early as January 2010 (1/1/2009 plus 12 months) or as late as July 2011 (12/31/2009 plus 18 months). E.ON U.S. believes that the statement should be modified to: read " that begins 12-18 months from the beginning of the current calendar year". This would limit the beginning of the current window to be January 2010 or July 2010.
Midwest ISO	No	Year One: At a minimum the SDT needs to address the applicability of this definition to include both the Transmission

Organization	Yes or No	Question 8 Comment
		Planner and Planning Coordinator. The Year One definition needs additional clarification with the current calendar year. According to the definition, Year One can start any time between 12 and 18 months from a current calendar year. Suggested definition for Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins at least 12-18 months from the end of the current calendar year.
BPA		Definition of terms - Year one: The current draft defines "year one" as "the planning window that begins 12-18 months from the current calendar year". However it's not clear: 1. When this 12-18 months should start to be counted. Is it counted from Jaunuary 1 of this calendar year, or Dec. 31 of this calendar year, or somewhere in the middle of the year depending on the planning entity's choice. 2. Does this calendar year refer to the year when the annual assessment report is submitted, or the calendar year when the annual assessment is started? For example, we may start to work on an annual assessment report in late 2009 but finally complete it in early 2010. In this case which year should be the "current calendar year" for the report? Each year in July BCTC receives a new load forecast, which covers the next 10 years with year 1 starting on April 1 of the next calendar year. If we determine the TPL "year one" by counting 12-18 months from the beginning of this calendar year, we are oke to use this new load forecast. If we determine the TPL year one by counting 12-18 months from the end of this calendar year, the new load forecast for year 1 and year 10 are already out-of-date by the time we receive them. Clarify which year is the "current calendar year" and when is the start of the 12-18 months.

Response: Rather than removing the specification, the SDT has revised the definition to clarify the reference point.

The revised definition is:

> **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

Organization	Yes or No	Question 8 Comment
TVA System Planning	No	TVA suggests adding back the following to the Bus-tie breaker definition that was contained in Posting #2: Substations configurations such as ring bus, breaker and a half, or double bus double breaker protection schemes do not use bus tie breakers. TVA believes that this additional wording helps explain this definition much more clearly. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now

Organization	Yes or No	Question 8 Comment
		considered to be Load Reduction, Supplemental Load Loss, or something else? Should Supplemental Load Loss be further defined as load that is disconnected from the network by end-user equipment responding during duration of the fault as well as to post contingency system conditions? Also the definition of Supplemental Load Loss may benefit from some examples in the definition to further help clarify. Please clarify how Supplemental Load Loss would be included in the stability analysis. The second sentence in the Year One definition is rather confusing. We would suggest changing “calendar year” to “date”. Otherwise it may be interpreted that Year One would begin 12 to 18 months from the end of the current calendar year. Suggest from “beginning”. Load Reduction ? Please clarify whether this includes both load response and operator initiated action, such as in changes to transformer LTC. Should definition also include that this load is continuing to be served? Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss defintion. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that is removing this equipment (and conversely, load that is not disconneted "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that inherently disconnects from the System as a consequence of (or "in response") to the conditions created by the System event."

Response: The SDT removed the statement on Bus-tie Breakers because comments were received to indicate that although it was true for most applications, it wasn’t universal and examples were provided where bus tie breakers were used between ring buses, etc. No change made.

The definition of Non-Consequential Load Loss has been revised to provide greater clarity.

> **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

The definition for Supplemental Load Loss has been deleted.

The definition for Year One has been revised to reflect your comment. The revised definition is:

> **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.

The definition for Load Reduction has been deleted.

In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘h’ in the header to Table 1.

Organization	Yes or No	Question 8 Comment
Header note 'b': Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. The definition for Supplemental Load Loss has been deleted.		
Southern Company	No	We disagree with deleting the definition of system stability and generating unit stability. The proposed definition for Year One reads as follows Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current year. Please clarify if this refers to the first "calendar" year when a Transmission Planner becomes responsible for assessments. If so, then add the word "Calendar" so that it reads "Year One: The first calendar year ..... .
Response: The SDT deleted the difference between generator unit Stability and System Stability due to a majority of comments received from industry in a previous posting. No change made. The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
United Illuminating	No	Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
Northeast Utilities Central Maine Power Company	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Non-Consequential Load Loss: Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)
ISO New England, Inc.	No	Refine load loss definitions as follows.Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions resulting from following a Planning or Extreme Event. Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. (Priority Comment)

Organization	Yes or No	Question 8 Comment
Response: The definition for Load Reduction has been deleted. The SDT has simplified the Non-Consequential Load Loss definition and has eliminated the references to Supplemental Load Loss and Load Reduction. The New definition is: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.		
System Protection and Transmission Planning Department	Yes	We appreciate the effort of the SDT to clarify "Consequential load loss", and think references to this term are clearer in this draft. Proxies?, used in R5, should be defined. See R5 comments for our suggestion.
Response: See response to question 5 comments. The term, "proxies" is not used in the revised standard.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican believes the SDT improved several of the definitions and believes additional changes are needed: For the bus-tie definition, what does "individual substation bus configurations" mean?? The consequential load loss states that it is load that "removed from service by a planned Protection System operation to isolate fault conditions". This implies that a contingency that does not involve a fault could never have consequential load loss. MidAmerican suggests that the words "to isolate fault conditions" be replaced with "in response to a contingency event". Alternatively, consider using the words in R3.3.1 which defines the same information but without referring to fault conditions. The definition of Long-Term Transmission Planning Horizon is confusing because it is not clear which term the words "when required to accommodate any known longer lead time projects that may take longer than ten years to complete" are meant to modify. MidAmerican believes the intent is that these words only apply to the years ten or beyond and not the entire period years six to ten and beyond. Therefore, we recommend that the words be changed by starting a new sentence in the definition and putting it in parentheses "(Years beyond ten years are required to accommodate any known longer lead time projects that may take longer than ten years to complete.) MidAmerican commends the SDT for improving the Year One definition. MidAmerican still believes the Year One definition is too confining. It indicates that the first year is defined as the planning window that begins 12-18 months from the current calendar year. This means if the regional entity provides models during the current calendar year in April, the responsible entity cannot use those models in conducting planning until a year that begins in May of the next year. Why delay the start of Year One? What is gained by this delay? MidAmerican recommends that Year One NOT be a defined term. This definition clarifies a term that does NOT need to be clarified for any reason. MidAmerican believe this is a fix for a problem that does not exist. Does the SDT have evidence of lack of compliance in this regard?? Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in

Organization	Yes or No	Question 8 Comment
		the TPL-001 standard. Modify the Planning Events definition more explicitly apply to the TPL-001 requirements. We suggest text of: Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard.
Response: Bus configurations could include flat buses, ring buses, breaker and a half, etc. The reference to fault conditions was intentionally used to exclude SPS action. A Contingency without a fault would be an inadvertent or mis-operation, which is not directly addressed by this standard. No change made. The SDT did not recognize a benefit to the proposed wording change for the definition of Long-Term Transmission Planning Horizon. No change made. The SDT believes that a near term study requirement is a necessary part of the standard and that a definition for Year One is a necessary component to achieve that objective. The SDT has received several constructive comments on this and has made revisions to the definition. Although revisions fall short of your suggestion, the SDT hopes that additional clarity will help. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year. As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made. The definition for planning events has been deleted.		
Gainesville Regional Utilities	Yes	But as referenced in question 5, I believe you need a good definition for the following terms; "cascading outages", "voltage instability", and "uncontrolled islanding".
Response: The SDT sees no reason to define "cascading outages", "voltage instability", or "uncontrolled islanding" in TPL-001-1. If Gainsville wishes to pursue, please draft a SAR. No change made.		
Progress Energy Florida, Inc.	No	PEF continues to disagree strenuously with differentiating between Consequential Load Loss and Non-Consequential Load Loss. PEF does not believe that load loss has anything whatsoever to do with demonstrating the robustness of the BES. The approach the SDT is taking with TPL-001-1 is essentially "Feeder Reliability", rather than BES Reliability. Should the SDT decide that they must continue with this approach, PEF will explore options for expressing concern about this at the FERC level. PEF is perplexed by the definition of Supplemental Load Loss. PEF, as a Transmission Owner, considers its "end-user" to be the Distribution System. PEF would therefore use this definition to design Distribution-side controlled load curtailment schemes that essentially qualify as Consequential Load Loss. If this is not the intent of the SDT, PEF suggests that the

Organization	Yes or No	Question 8 Comment
		SDT modify this definition to make its meaning clearer.
Response: The SDT has revised the definitions and notes in the table, which should clarify the reference to the end-user. Pertinent revisions are: **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
Ameren	No	Extreme Events definition references severity and probability. These terms should be included in the definition of Planning Events. Add a definition of Planned and Proposed facilities. Planned facilities address the near term deficiencies and have been approved with a financial commitment while proposed facilities address long term deficiencies for which no commitment is required today since they may change based on future evaluation. Revised Definitions are generally better than those from the previous version, but additional clarity could be provided. Consequential Load Loss ? Would an SPS to trip load qualify as a planned protection system? Load Reduction ? Please clarify whether this includes both load response and operator initiated action, as in changes to transformer LTC. Supplemental Load Loss - From a utility perspective, this would be considered as load response. Please clarify how Supplemental Load Loss would be included in the stability analysis. Table 1 suggests that it cannot be included to meet steady-state performance. Suggest that the following be added to the definition: Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.
Response: The definitions for both extreme events and planning events have been deleted. The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. An SPS does not qualify as a planned Protection System because it is not being used "to isolate the fault", which is a condition of the statement. The definition for Load Reduction has been deleted. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an		

Organization	Yes or No	Question 8 Comment
event shall not be used to meet steady state performance requirements.		
Manitoba Hydro	No	Consequential Load Loss: the wording “by a planned Protection System operation to isolate fault conditions” is awkward wording. The wording should be changed to “by a Protection System operation designed to isolate fault conditions”. Load Reduction: This definition is not needed and load reduction is not prohibited in the standard. It will take some effort to even measure such a load reduction in simulation. Given that there are four load related definitions, the standard would be simplified by deleting this term. Any voltage dependent load will be reduced for a low voltage condition. In steady state (P0), load is normally modeled as constant MVA load so load is constant. In the steady state period after a contingency, transformer taps and voltage control devices will restore voltage, and consequently, any load modeled as voltage dependent will be restored to pre-contingency level. The term is not used anywhere in the requirements of the standard - it is only included in Table 1 Note b in the definition of Non-Consequential Load Loss. We do not think it is needed. Supplemental Load Loss: Why did the drafting team decide to include Supplemental load loss? In Table 1, it is stated under "note b" that Supplemental Load Loss cannot be used to meet steady state performance requirements. Does this imply that it is acceptable for "non-consequential" induction motor load to trip off as a result of undervoltage during the disturbance due to its protection setting? It is possible that this load loss during a stability simulation may avoid the need to add dynamic reactive support. Can the drafting team clarify the intent of the standard or delete Supplemental Load Loss. At minimum, the TP/PA should identify the minimum transient voltage that they are planning the system for. In that way, any load loss for unplanned events that cause lower transient voltages or load loss that occurs at a higher transient voltage wouldn’t be a violation. Also, unless the end-user load is modeled in detail, or a proxy is used, the planner will not know if such load exists or would be lost in the simulation.
Response: The definition for Consequential Load Loss has been revised to reflect your comment. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. In association with the changes in definitions, the SDT has revised note ‘b’ and added note ‘h’ in the header to Table 1. **Header note ‘b’:** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note ‘i’:** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.		
National Grid	No	Comments: Can the definitions of the “Planning Horizon” in the FAC, the “Long-term Planning” Time Horizon (italicized and in parentheses next to the Violation Risk Factor), and the “Near-Term” and “Long-Term Transmission Planning” be included in the definitions section to avoid confusion” Refine load loss definitions as follows. Consequential Load Loss: All Load that is no longer served by any Transmission

Organization	Yes or No	Question 8 Comment
		Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. Comment It is not clear if Consequential load includes load that is connected to transmission within an island. Suggest revising the definition to "..load no longer served by the Transmission System (or perhaps by the BES?) as a result of Transmission Facilities being removed?" Load Reduction: Quantity of Load that is reduced due to lower voltage conditions resulting from a Planning or Extreme Event. Comment "Load Reduction" as written is the load remaining after the reduction. This should be rewritten to indicate it is the change in load from the previous value to that still connected. Also, the defined term "Load Reduction" is counter to what most engineers consider to be a load reduction and as written it does not seem necessary to define this term. Most engineers associate Load Reduction as a manual or automatic action by a customer to reduce demand. As defined it appears that Load Reduction refers only to the voltage sensitivity of load which should be captured in the system model if it is necessary to model this effect. Therefore the reference should be changed from "Load Reduction" to "Voltage Sensitive Load Loss". Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. Comment The definition is indirect. Suggest to revise the definition to be direct by stating "Intended post contingency loss of load (other than Interruptible Load, Supplemental Load or Load Reduction) caused by operator or SPS (RAS) action. Planning Events: Events that require Transmission system performance requirements to be met.Comment - Suggest "Events for which Transmission system performance requirements shall be met". Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.Comment - Suggest rewording last phrase to "..responding to System Contingency conditions." - or perhaps just "..responding to System conditions." Year One: The first year that a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the current calendar year. Comment - Suggest rewording second sentence to "This is further defined as beginning 12-18 months from the current calendar year." - This avoids the awkwardness in present draft of seeming to define Year One as a planning window as well as a particular year.

Response: The *Time Horizon* term at the end of the requirement deals with mitigation time periods (as shown below) and is not connected to the assessment time frames. Time Horizons are a consideration when there is a violation of a requirement – the impact to the BES of violating a requirement with a long-term planning horizon is not expected to be as severe as the impact associated with violating a requirement with a real-time operations time horizon. No change made.

Mitigation Time Horizon

The time horizons available for mitigating a violation to a requirement include the following:

- **Long-term Planning** — a planning horizon of one year or longer.
- **Operations Planning** — operating and resource plans from day-ahead up to and including seasonal.
- **Same-day Operations** — routine actions required within the timeframe of a day, but not real-time.

Organization	Yes or No	Question 8 Comment
• **Real-time Operations** — actions required within one hour or less to preserve the reliability of the bulk electric system. • **Operations Assessment** — follow-up evaluations and reporting of real time operations. The definition for Consequential Load Loss has been revised to reflect your comment. **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definition for Planning Event has been deleted. The definition for Year One has been revised to reflect your comment.. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Entergy Services, Inc	No	Include a definition of “planned facilities”: Facilities that address the near-term deficiencies and have been approved with a financial commitment. In Posting #2, undervoltage load shed, underfrequency load shed, and Special Protection Schemes were considered to be Non-Consequential Load Loss. Are these now no longer considered to be Non-Consequential Load Loss but instead now considered to be Load Reduction, Supplemental Load Loss, or something else?
Response: The SDT tried to address the concepts of planned and proposed in a prior posting. The response from industry strongly discouraged the standard from delving into the distinction. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
BC Hydro	No	Comments: In almost all instances, the word “horizon” should be changed to “period” in both the definitions and throughout the standard. The word horizon refers to the end of the period; it literally means, “the limit of one’s mental outlook” and the horizon is normally the furthest we can see. A long-term horizon-year study would be a study of conditions expected in the last year of the long-term planning period (often the 10th or 20th year). A long-term horizon-year study would not be expected to refer to a series of studies of each year in the long-term planning period.
Response: The reference to ‘Horizon’ is not something new and the SDT does not agree with changing it. No change made.		
PJM	No	Planning Events and Extreme Events should refer to the lists in the tables since there is no other way to understand which contingency falls into what definition. The designation is deterministic and somewhat arbitrary but commonly accepted.

Organization	Yes or No	Question 8 Comment
Response: The definitions for planning events and extreme events have been deleted.		
American Electric Power	No	"Load Reduction" does not need to be retained as a defined term; in fact it only appears once in the draft standard at the top of Table 1. In addition, it is well understood that load is sensitive to voltage, so it seems unnecessary to call attention to it. Furthermore, the "Supplemental Load Loss" definition should also be removed. These definitions are not generally relevant to planning studies. Neither steady-state nor stability planning studies should acknowledge or rely on "Supplemental Load Loss" because it is simply unpredictable without detailed load device protection data. In fact, properly set minimum voltage limits should ensure that no appreciable load is tripped by customer equipment response as long as that equipment meets generally accepted equipment and design standards. For the same reason, steady-state planning studies should not rely on "Load Reduction" because the planning function is supposed to ensure that a designated forecasted load can be served under credible contingencies. However, it is okay that stability studies acknowledge and rely on load voltage sensitivity ("Load Reduction"), and in fact this is required due to the nature of the analysis and cannot be otherwise. Therefore, there is no need to call attention to it.Given the above comments, the remaining two load loss definitions should be further clarified, though not changed substantively, to read as noted below. Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Facilities being removed from service by a planned Protection System operation to isolate fault conditions. It excludes Load that is disconnected from the network by load internal protection or end-user equipment responding to post-Contingency System conditions. Also, it excludes Load that remains connected to the System, but that may be reduced due to lower voltage conditions as a consequence of a Planning or Extreme Event.Non-Consequential Load Loss: Any Load loss intentionally caused due to automatic system protective functions such as UVLS, special protection systems, or as the result of operating procedures. Finally, the lettered bullets at the top of Table 1 need to be modified as appropriate to reflect the above comments that load loss due to internal load protection or end-user equipment, what was called "Supplemental Load Loss", should NOT be permitted in complying with either steady-state or stability performance criteria. Load that remains connected to the System, but that may be reduced due to lower voltage, should NOT be permitted in complying with steady-state performance criteria, but should be allowed, by necessity, in complying with stability performance criteria.
Response: The definitions for Load Reduction and Supplemental Load Loss have been deleted. The definitions for Consequential and Non-Consequential Load loss have been revised **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault . **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including		

Organization	Yes or No	Question 8 Comment
Load that is disconnected from the System by end-user equipment. In association with the changes in definitions, the SDT has revised note 'b' and added note 'i' in the header to Table 1. **Header note 'b':** Consequential Load Loss and consequential generation loss are acceptable as a consequence of any planning or extreme event excluding P0. **Header note 'i':** The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
Northern Indiana Public Service Company	No	The definitions need clarification, especially if they will be extracted from the standard when approved and included in the NERC Glossary. The SDT should include a Technical Writer to clarify the proposed language.
Response: Thank you for your response.		
Platte River Power Authority	No	Non-Consequential Loss of Load - It is not clear in all the Load Loss definitions where planned load shedding or "controlled interruption of electric supply" belong. However, the NERC Webinar on June 30 was very helpful, and I make the following comment in line with the answer I heard to my question. A "Yes" in the last column of Table 1 means that planned load shedding or "controlled interruption of electric supply" is allowed for that Category of Contingencies. (For a P2.2 Bus Section Fault, SLG, HV, "Yes", one could choose to implement a planned load shedding procedure or scheme to meet system performance requirements.) Planned load shedding may be manual load shedding or automatic actions such as direct load tripping or UVLS for example. Therefore, please add mention of the planned load shedding or the "controlled interruption of electric supply" and list specific examples in the definition for "Non-Consequential Loss of Load."
Response: The SDT has decided that it is inappropriate to include examples within a Standard's definition. The SDT is concerned that an example isn't all inclusive and it will create opportunities for loopholes. No change made. UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.		
American Transmission Company	No	We suggest the following comments: Add a Consequential Generation Loss definition because both load and generation loss can be considered, but there is only Consequential Load Loss definition. We suggest text of: "Consequential Generation Loss: All Generation that is no longer delivered to any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions.

Organization	Yes or No	Question 8 Comment
		Expand the Consequential Load Loss definition to include protection for abnormal operating conditions. We suggest text of: "Consequential Load Loss: All Load that is no longer served by any Transmission Facilities as a result of the Transmission Facilities removal from service by the operation of the installed Protection Systems designed to isolate fault conditions or otherwise protect the Transmission Facilities from abnormal operating conditions. Expand the Load Reduction definition to include consideration of TOP judgment and established protection schemes. We suggest text of: "Load Reduction: The reduction of Load that is still connected to the System, but in the judgment of the Transmission Operator or through the previous established Special Protection Systems, Under-frequency Load Shedding programs, Over-frequency Load Shedding program, should be reduced to overcome to lower voltage conditions following a Planning or Extreme Event. Modify the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard. Modify the Planning Events definition to more explicitly apply to the TPL-001 requirements. We suggest text of: "Planning Events: Events that are identified in the steady state and stability performance requirements set forth in the TPL-001 standard. Expand the Year One definition to include the PC, refer to the Planning Assessment, and refer to the current calendar year. We suggest text of: "Year One: The first year that each Transmission Planner and Planning Coordinator is responsible for conducting a Planning Assessment. This is further defined as the planning window that begins 12-18 months from the current calendar year.

Response: Requirement R2, part 2.7.1 allows for generation tripping and run-back, so a definition for Consequential Generation Loss is not required.

The definition for Consequential Load Loss has been revised to provide greater clarity.

> **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .

The definition for Load Reduction has been deleted.

UVLS and UFLS are not precluded in the Corrective Action Plan for those events where controlled load shedding is allowed. The Standard does not address the acceptability of the tools to be used for any Corrective Action Plan. No change made.

As stated in the "Purpose" the Standard establishes Transmission System planning performance for the BES. Repeating that within the Standard creates opportunities for confusion whenever it is not specifically noted. The SDT wants to minimize confusion by not repeating applicability throughout the document. Also the Planning Assessment involves more than remedying identified deficiencies. For example, it may also confirm that there are no deficiencies or it may evaluate the impacts of schedule changes in the Corrective Action Plans. No change made.

The definition of planning events has been deleted.

Organization	Yes or No	Question 8 Comment
The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		
Duke Energy	No	Bus-tie Breaker definitions still seems somewhat generic and the use of 'configurations' causes uncertainty. Revise Bus-tie Breaker to read, "A circuit breaker whose intended purpose is to connect two individual substation buses." "Bus-tie" is not capitalized in the Table. Consequential Load Loss must include load that is lost due to the inherent response of the particular type of load. Some motors, lighting and processes will naturally trip during an event, although not as a result of the protection system. It may have been the intent of the SDT to include this phenomenon in the Supplemental Load Loss definition. However, this definition includes the phrase, "by end-user equipment", and that makes one think that there are devices at the end-user location that are removing this equipment (and conversely, load that is not disconnected "by" end-user equipment cannot be included). Also, the term "post-Contingency" can be confusing because in the case of faults, this phrase is not clear if it means conditions after the fault initiation itself or only after the clearing of the fault. Revise Supplemental Load Loss to read, "End-user Load that, due to its characteristics, disconnects from the System in response to the conditions created by the System event."
Response: The definition as proposed by Duke Energy for a Bus-tie Breaker would apply to every breaker in any configuration. The definition in the Standard is trying to limit the application to a connection between configurations of buses, which could include flat buses, ring buses, breaker and a half, etc. The SDT is deliberately using the term configuration to avoid unintentionally excluding a particular configuration. No change made. The table has been updated to capitalize the term, “Bus-tie Breaker” where used. The definition for Supplemental Load Loss has been deleted. The definition for Consequential Load Loss has been revised to reflect your comments. The revised definition is: **Consequential Load Loss:** All Load that is no longer served by the Transmission System as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault .		
Independent Electricity System Operator	No	Is Year One intended to coincide with a calendar year or can it start in any month of the year? We suggest the following change to the definition. Insert “calendar” before “first” and “within” before “12” and change “from” to “of”. NERC should seek to reinstate a definition of “cascading outages” and create one for “uncontrolled islanding”.
Response: The definition for Year One has been revised to reflect your comment. The revised definition is: **Year One:** The first year that a Planning Coordinator or a Transmission Planner is responsible for assessing. This is further defined as the planning window that begins 12-18 months from the end of the current calendar year.		

Organization	Yes or No	Question 8 Comment
The SDT sees no reason to define "cascading outages" or "uncontrolled islanding" in TPL-001-1. If IESO wishes to pursue, please draft a SAR. No change made.		
Kansas City Power & Light	Yes	
Dominion - Electric Transmission	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent changes
FMPA	Yes	
CPS Energy	Yes	
JEA	Yes	
Brazos Electric Cooperative	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 8 Comment
Minnesota Power	Yes	
Orlando Utilities Commission	Yes	Good Job.
ReliabilityFirst Corporation	Yes No	It would have been nice if a red lined list of these changes is attached to the standard.
Response: Thank you for your response. However, due to other comments, several definitions have been changed as shown above.		

9. Do you agree with the changes in the performance elements and notes in Table 1? If not, please provide specific comments by note number, note alpha character, or performance category. Please note that footnotes 5 and 10 are handled separately in question 10.

Summary Consideration: While many comments were received from industry for this question, the vast majority of them were of a clarifying nature. While there were still a few questions on raising the bar for 300 kV, the actual performance elements now seem to have been honed to a point that is acceptable. The following changes were made due to industry comments:

Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Header note 'c': Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event.

Header note 'f': Facility Ratings shall not be exceeded.

Header note 'k': Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.

P4: Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus

P7: Any two adjacent (vertically or horizontally) circuits on common structure

Extreme event 'a': Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency

Extreme event steady state 1: Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

Extreme event Stability 1: With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

Footnote 2: Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Footnote 3: Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.

Footnote 7: Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.

Footnote 10: A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing .

Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less.

Organization	Yes or No	Question 9 Comment
Northeast Power Coordinating Council	No	For Steady State & Stability: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsP5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary’s Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h “ Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should

Organization	Yes or No	Question 9 Comment
		be used in this simulation. Comments on Footnotes “ Table 1- We recommend renumbering the Footnotes table to be Table 3. Footnote 1.a.i “ Should clarify that this requirement refers to generator units that are connected to the BES system. Footnote 1.a.ii “ Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can’t lose more than that permissible by the Planning Coordinator. Also change “pull out of synchronism” to “lose synchronism” in this sentence and in the second sentence. (Is “Lose synchronism” a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized? Therefore, there needs to be some sort of qualifier on this requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 “ We recommend revising the wording of the last sentence to “A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 “ We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying “and lower”. As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase “?(EHV) Facilities defined as greater than 300 kV?? with “?(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator?? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, “or for 5 towers or less. This is consistent with NPCC criteria.

Response: NPCC suggested adding the word ‘Transmission’ to the beginning of header note ‘a’. In TPL-001-1, draft 4, the SDT made a change to header note ‘a’ as suggested by the commenter but modified it to be ‘BES Transmission’.

Header note ‘a’: BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

Additionally it is proposed to state in header note “b” that Load Reduction is not an acceptable means to meet steady state performance requirements. Regarding the

Organization	Yes or No	Question 9 Comment

suggested change to header note 'b', no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Depending on the assumptions used by the Transmission Planner, a Load Reduction could occur in the steady state analysis.

In response to industry comments on TPL-001-1, draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate the failure of a Protection System design, and it is not based on any particular component of that design. Also, please see the Summary Considerations for Question 7 from the second posting comments; specifically item 3 on page 207.

The suggested wording change to include 'adjacent' for the P7 planning event is accepted by the SDT and reflected in TPL-001-1, draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 11.

> **P7:** Any two adjacent (vertically or horizontally) circuits on common structure

The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Regarding extreme event Stability item 2a, the response to your P5 comment above applies. No changes were made in regard to extreme event 2a.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.

The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. The indicated change was not made by the SDT as it was felt that it added no additional clarity.

Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3. No change made.

Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made.

The comment on footnote 1.a.i is redundant and already addressed above. Footnote 1 has been deleted and moved into Requirement R4, parts 4.1.1 – 4.1.3.

The SDT accepts the NPCC proposed change for footnote 3 (now footnote 2).

> **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria.

Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity.

> **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish

Organization	Yes or No	Question 9 Comment
between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		
Transmission Planning	No	COMMENT: P2-1. Opening of Breaker(s) w/o fault Event: Does the modeling of this event require that the line remains energized up to the breakers" This will require adding a bus at each end with a zero impedance branch connection to "open" representation of breakers. Explicit modeling of a circuit breaker opening would require a substantial modeling effort and would not produce results more adverse than any of the other P2 contingencies. Why is this necessary? Recommend deletion of this planning event. The threshold of higher performance for facilities above 300 kV may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. We do not agree that such a threshold is necessary or warranted.
Response: In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1. There is no need to show a line energized up to the breakers that opened. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. The SDT does not believe the proposed higher performance requirements for the EHV will cause a disincentive for the EHV infrastructure. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Table 1 titles: The word "Requirements" needs to be added to the Table 1 titles in the existing tables. Table 1 " Steady State & Stability Performance Requirements Planning Events Table 1 " Steady State & Stability Performance Requirements Extreme Events Table 1 " Steady State & Stability Performance Requirements Footnotes (Planning Events and Extreme Events)Steady-state vs. stability analysis: We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: "Any two adjacent circuits on a common structure.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see		

Organization	Yes or No	Question 9 Comment
Requirements R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. No change made. The suggested wording change to include “adjacent” for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure		
Duke Energy	No	Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, ?Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).
Response: The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 (formerly footnote 12) was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
Modesto Irrigation District	No	On page 20 under Table 1, why are “SLG” (i.e., single line to ground) type faults still specified when footnote 3 on page 24 indicates that analyzing three phase faults is sufficient ? On page 20 under Table 1 part f, changing “post transient” to “post Contingency” may be confusing to most analysts as post-transient is a well defined term that has been in use for many years, and is even referenced in Table W-1 of the WECC supplemental planning standard TPL - (001 thru 004) “ WECC “ 1 - CR. On page 20 under Table 1 part g, does that mean that for Planning Event P0 the analyst is not required to simulate a fault with normal clearing without a loss of any system element, in order to demonstrate system stability “ On page 24 under Footnote 1 a ii, I would like to suggest that we add the phrase “(unless the relays are equipped with blinders and timers)” right after the phrase “must not pass through relay characteristics”. This is because the blinders (i.e., straight line characteristic of a distance relay) and timers can be used to prevent distance relays from tripping when power angle swings cause the apparent impedance the distance relays see to cross into the distance relay’s zone of protection.

Organization	Yes or No	Question 9 Comment
Response: When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate, a planner may simulate the 3-phase fault and if performance criteria are met then no further work is needed since the 3-phase fault has a greater BES impact than an SLG fault. However, if the 3-phase screening does not meet performance criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. Please see footnote 2. The change from post-transient to post-Contingency was made in the last draft since the note refers to a steady-state timeframe. No change made. No stability review for the P0 event is required. Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the indicated change was not made as the SDT does not feel that it would add any clarity.		
Pepco Holdings, Inc. - Affiliates	Yes	PHI does not disagree with the performance elements, but suggests that the table would be improved if a leading sentence were added to the definition section at the beginning of the table.
Response: Without a specific recommendation, the SDT is unable to make a change.		
MRO NERC Standards Review Subcommittee	No	MRO NSRS suggests the following changes:MRO NSRS believes reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. MRO NSRS suggests modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. MRO NSRS proposes limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. MRO NSRS suggests text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected to disconnect automatically for each Contingency?. Modify the P3 Category performance criteria to apply only to the loss of two generators because probability of the loss of two base load generators is an order of magnitude higher than the loss of a generator and any other transmission element. MRO NSRS suggests the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. MRO NSRS suggests this text: 1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. MRO NSRS suggests this text: a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. MRO NSRS suggests this text: b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State

Organization	Yes or No	Question 9 Comment
		section. MRO NSRS suggests this text that is similar to Steady State, Item 3.b: i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: 7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The SDT has added the suggested wording. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The SDT disagrees with the proposed change to the P3 event. The loss of a generator is highly probable and the SDT and other stakeholders support the P3 requirement to meet the P1 criteria for the loss of a generator unit plus the loss of any other P1 element, not just another generator. No change made. The SDT has added the suggested wording. **Extreme event 'a':** Simulate the removal of all elements that Protection Systems and automatic controls are expected to disconnect for each Contingency The SDT disagrees that the proposed wording of extreme event 2a is needed since the proposed change is not substantive. The SDT disagrees that the proposed wording of extreme event 3b is needed since the proposed change is not substantive. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	P5 should not be a Planning Event. PRC Standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry-accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies Stability Extreme 2g needs a note like number 12 that excludes short distances. Stability Extreme 2h: Is this meant to be an event initiated by a 3LG fault or is it a catastrophic event that leaves all the elements at a station with a 3LG fault. If it is the former, then 2h needs a note to limit this to locations where actual events could lead to the loss of the entire station. There is no need to study this if there are no protection system events that lead to loss of the whole station (there would be no scenario to model). If 2h is meant to represent some catastrophe that causes all the elements at the site to experience a fault, then some clarification is needed to get consistent studies. Possibly rewrite 2h as, "Assume all the buses at a single voltage level (one voltage level plus transformers) experience an event that results in a 3LG fault and disables local protection (fault must clear from remote stations or other side of transformer).

Organization	Yes or No	Question 9 Comment
Response: In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event Stability 2f and steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	“The word "Requirements” needs to be added to the Table 1 titles in the existing tables.oTable 1 ? Steady State & Stability Performance Requirements Planning Events Table 1 ? Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Footnotes (Planning Events and Extreme Events)? We recommend that Table 1 be split back as was done in the previous draft to handle the 1) steady-state and 2) stability performance requirements. This is needed to provide clarity on which contingencies apply to steady-state and which apply to stability analysis. Table I, P7.1: It would not be likely to lose the two outside circuits on a vertically configured structure and not lose the middle circuit. Change the wording to: Any two adjacent circuits on a common structure. The word "Requirements” needs to be added to the Table 1 titles in the existing tables.oTable 1 Steady State & Stability Performance Requirements Planning Events Table 1 Steady State & Stability Performance Requirements Extreme Events Table 1 Steady State & Stability Performance Requirements? Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No". The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for SERC Members to fix all such events in several remote areas that would have very little impact on the overall reliability of the SERC Members? bulk system. SERC Members believe that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways.

Organization	Yes or No	Question 9 Comment
		P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies.
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The tables were combined for convenience since each Contingency event was the same in each table and based on stakeholder input. The Fault Type column adequately describes what fault type is required for study in the dynamic Stability timeframe. The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. **P7:** Any two adjacent (vertically or horizontally) circuits on common structure In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event. FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
FirstEnergy Corp	No	A. Note b: Please see comments in our response to Question #8 related to note b and the Supplemental Load definition. B. Note b: We believe the SDT inadvertently allowed the used of Load Reduction to meet Steady State performance requirements. We suggest text of: "However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements." C. Note b: If our assumption is correct on item B above, we fail to see the need to define two terms Load Reduction and Supplemental Load Loss which are not permitted within the Table 1 performance requirements for steady-state nor mentioned and used within the requirement language. It appears that the Load Reduction and Supplemental Load Loss are permissible within the stability timeframe. It is not understood why it would be valid to account for these in the stability timeframe but not steady-state. D. Note i: What if the TP or PC has no criteria for transient voltage response? The standard should have a requirement that ensures that such a criteria is documented by the entity if it is intended to be used within the TPL-

Organization	Yes or No	Question 9 Comment
		001-1 standard. E. P2-3: It seems that footnote 10 should apply to the EHV criteria stated in the column titled "Interruption of Firm Transmission Service Allowed" since it applies for the P5-1 through P5-5 EHV criterion. F. P5: We agree with the change made in Draft 3 to remove the reference to "single component" of the Protection System. Additionally, the SDT clarified its intended purpose of the P5 event as stated in the Draft 2, Q7 Summary Considerations:"A number of commenters expressed concern related to Planning Event P5 Protection System Failure and the need to evaluate a single component failure of a BES Protection System; particularly a failure of a station battery. The SDT has revised the P5 Planning Event description to remove the reference to single component failure and the event description was changed to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. A Protection System failure resulting in loss of the substation (one voltage level plus transformers) would not qualify as a P5 Planning Event since that event is considered an Extreme Event. A Standard Authorization Request (SAR) has been issued for industry comment (1/20/2009 through 2/18/2009) based on work completed by the System Protection and Controls Task Force (SPCTF). The proposed project will address the need for Protection System redundancy, based on an n-1 failure of individual components of the Protection System."It is suggested that a footnote be added the text Protection System as stated in the P5 Event Description. The footnote should read "Failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. This contingency is NOT based on failure of any particular single component of the Protection System design." This footnote will help clarify the intent without having to rely on the Comment record established during this standard development project. G. In the Extreme Event table we suggest event identifiers that are similar to those used in the Planning Events table. For Extreme Steady State we suggest ESS1, ESS2-1, ESS2-1... ESS2-5, ESS3-1 and ESS3-2. For the Extreme Stability we suggest ES1, ES2-1...ES2-9. This will provide a short-cut reference for industry when referring to a particular event.

Response:

A) Please see our comments related to the Supplemental Load definition in question 8.

B) Regarding the suggested change to header note “b”, no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc.

C) Voltage sensitive Load loss is permitted in the transient Stability timeframe as it is common in Stability simulation tools to assume a certain percentage of Load is removed based on motor stalling. To the extent a Transmission Planner accounts for this within their analysis, the standard does not prohibit its use in the Stability timeframe. However, for steady-state thermal and voltage criteria reviews the use of voltage sensitive Load loss is prohibited. The definition of Load reduction has been deleted and the concept has been incorporated in the definition of Non-Consequential Load Loss.

D) The standard drafting team has added new Requirement R5 to explicitly require criteria for transient voltage criteria.

Organization	Yes or No	Question 9 Comment
R5 Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. E) Footnote 10 (now footnote 9) does not apply since P2-3 is classified as a single Contingency. F) In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description. The proposed footnote was not accepted by the SDT. **G)** Regarding the proposed short-cut references to the extreme events, the SDT disagrees. No change made.		
TVA System Planning	No	The existing TPL 002-0 allows for some local load to be dropped for a single contingency event as long as the Bulk system reliability was not impacted. However there is no such allowance any longer for losing such load for a single contingency in the proposed draft. It would be very expensive for TVA to fix all such events in several remote areas that would have very little impact on the overall reliability of the TVA bulk system. TVA believes that the capital spent for these fixes could be used to better strengthen the overall bulk system in much better ways. P5 should not be a planning event. PRC standards address protection system failures. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. Stability Extreme 2.g, and Steady State 2.b. both need a note like footnote number 12 that excludes short distances. Suggest footnote #12 be modified to include right-of-way in addition to structures.
Response: In regards to a proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement. In P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The SDT has set the threshold at 1 mile or more, consistent with footnote 12 (now footnote 11). Footnote 11 was revised to account for both the common tower and common ROW exemption. Footnote 11 has been added to the extreme event steady-state 2b.		

Organization	Yes or No	Question 9 Comment
Footnote 11: Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
Exelon Transmission Planning	No	Table 1 comments in general: Even after modification from the previous version, it is still not clear if the "BES Voltage Level" applies to the contingency element voltage leFRCCan overload on a 138 kV line, is non-consequential load loss allowed on the 138 kV system? There is a concern about the lack of definition related to the failure of a "single Protection System" this could be widely interpreted. Would over tripping for line faults fall into this definition?
Response: The BES Voltage Level column applies to the System voltage of the Facilities removed from service by the planning event studied. In the example provided by Exelon, Non-Consequential Load Loss would not be permitted since the outaged facility is at the EHV level. No, over tripping is mis-operation and that does not fall into this definition.		
United Illuminating	No	Steady State & Stability comments as follows: Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more

Organization	Yes or No	Question 9 Comment
		commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Northeast Utilities	No	Steady State & Stability are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements Non-Consequential Load Loss Allowed Comment (priority comment):We highly recommend that the standard as written should not allow non-consequential load loss to resolve any violation arising from the planning events in Table 1 (except when considering spare equipment strategy together with events P3 or P6). We believe that planning for reliable power should discourage load loss mitigation. Therefore, the column for the "Non-Consequential Load Loss Allowed" in Table 1 should all have entries of "No". P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and, if appropriate, exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary's Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h ? Eliminate this requirement or change to loss of station following three-phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Comments on Footnotes Table 1- We recommend renumbering the Footnotes table to be Table 3. Note 1.a.i " Should clarify that this requirement refers to generator units that are connected to the BES system. Note 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence

Organization	Yes or No	Question 9 Comment
		to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to "A three-phase fault study indicating criteria are being met is sufficient evidence that a SLG fault condition would also meet criteria. Note 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".
Central Maine Power Company	No	Steady State & Stability comments as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements P5 Priority Comment As written, this requirement is overly severe. This would require the simulation of a ?dead? station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Extreme Event Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Extreme Event Stability Condition 2 Note h " Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Footnote 1.a.ii " Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Footnote 1.a.i, states "For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There is the potential for this requirement to be taken too far. Does this mean that someone's 4 kW generator at home needs to remain synchronized" Therefore, there needs to be some sort of qualifier on this

Organization	Yes or No	Question 9 Comment
		requirement. Suggested wording: "For Planning Event P1: No generating unit or units greater than 20 MW and directly interconnected at 100 kV or above shall be allowed to lose synchronism. Note that synchronism applies to conventional synchronous generators and may not apply to other generation technology." Footnote 3 " We recommend revising the wording of the last sentence to "A three phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Footnote 4 " We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". Footnote 12 " We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.

Response: The stakeholders suggest adding the word "Transmission" to the beginning of header note "a". Additionally it is proposed to state in header note "b" that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note "a" as suggested by the commenter but modified it to be "BES Transmission…". Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the load reduction definition has been deleted and incorporated in Non-Consequential Load.

Header note 'a': BES Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur.

The SDT agrees that Non-Consequential Load Loss should be discouraged, however, many of the events contained in Table 1 are very low probability events where intentionally dropping load to protect the integrity of the remainder of the BES may be an acceptable solution. Throughout the development process, the SDT has reviewed whether to allow Non-Consequential Load Loss for each event within Table 1 and has determined that "Yes" is the appropriate response where it is used within this column. No change made.

In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and is not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description.

The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).

P7: Any two adjacent (vertically or horizontally) circuits on common structure

The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe.

The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks

Organization	Yes or No	Question 9 Comment
within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3 but the SDT did not make the suggested change as it felt that it didn't add any additional clarity. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and the wording presently used, "pulling out of synchronism", is sufficient. No change made. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The comment on footnote 1.a.i is redundant and already addressed above. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 for clarity. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggest that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		
System Protection and Transmission Planning Department	No	The order of scenarios listed in the table should reflect the relative probability of events. Did the SDT intend to order listed contingencies by relative severity? Could it do so" Planning Events - SLG fault simulation should not be required. They should only be performed if more severe than 3-phase faults. A SLG fault with delayed breaker clearing could have more system impact than a 3-phase fault. The "Extreme Events" portion of the table is confusing " partly because the form differs from the Planning Event portion. The difference between contingencies in the Planning portion and the Extreme portion is not clear.

Organization	Yes or No	Question 9 Comment
		Perhaps the Extreme Event portion could be a separate Table. Extreme Events / Stability section - Why specifically require "g. SLG fault on all Transmission lines on a common Right-of-Way. "
Response: The order is not based on probability. When a SLG fault type is specified in Table 1, it is the fault that must be satisfied to meet performance criteria for the referenced planning event. Since 3-phase faults are simpler to simulate a planner may simulate the 3-phase and if performance criteria are met, then no further work is needed since the 3-phase fault has a greater BES impact than a SLG fault. However, if the 3-phase screening does not meet criteria, then the planner must perform the more labor intensive SLG analysis to determine whether or not performance criteria are being met. See footnote 2. The extreme events area of the table has not been reformatted. The SDT believes the table clearly delineates what is required in regards to studies required for stability and those required for steady-state. Regarding the extreme events Stability item "g" retains consistency with what is currently in the approved TPL-004-0 standard as a NERC category D7 event.		
PPL Energy Plus	No	The WECC suggests P4 penalizes EHV and if this is true, please re-write P4 to eliminate the penalty.
Response: In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Bonneville Power Administration PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, NV Energy San Diego Gas and Electric Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.

Organization	Yes or No	Question 9 Comment
Idaho Power California ISO		
Xcel Energy	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements.
Puget Sound Energy, Inc.	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker).
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.		
Western Area Power Administration	Yes	There is information within the notes that is not required to correctly understand and apply the TPL Standard. Examples are: 1. Note 1.a.i " the 2nd sentence is not needed to say what is not an out-of-step occurrence. 2. Note 9 is not needed to clarify what "internal" means.
Response: The SDT believes the notes provided help clarify the performance criteria stated in Table 1. No changes were made in Draft 4.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. We recommend consistant critera between P2.3, P4 and P7 that allow curtailment of firm service and loss of non-consequential load.
Response: The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
FMPA	No	Table 1 seems to have lost the requirement to be within Facility Ratings for single and double contingencies (e.g., the change in note "f" of Table 1). Are we missing something? If not, is this change intentional?

Organization	Yes or No	Question 9 Comment
		Footnote 10 does not seem to adequately highlight that Facilities should be within applicable ratings for single and credible double contingencies. The table is significantly improved from the prior versions and provides superior clarification over the existing standards. However, please explain why there is a performance difference between P2.3 (breaker failure), P4 (stuck breaker) and P7 (2 circuits on a common tower) for EHV. Considering the frequency of these events in actual experience, it would seem that 2 circuits on a common tower should have a more restrictive or equal performance to a stuck breaker performance, yet the performance requirements are just the opposite. We recommend allowing curtailment of firm service and loss of non-consequential load for a stuck breaker or failed breaker.
Response: In Table 1, header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. **Header note 'f':** Facility Ratings shall not be exceeded. Regarding footnote 10 (now footnote 9), the issue was addressed by adding Facility Ratings back in. The SDT appreciates your support in the overall table revisions. In the early stages of standard development, the SDT reviewed the various Contingency classifications for likelihood and impact. Single Contingency events were placed higher in the table than multiple Contingency events. The SDT determined that since the EHV System (300kV and above) was utilized to carry large amounts of power between generation and Load and typically not directly servicing end-user customers, higher performance expectations were appropriate for some higher impact events. The P2.3 (breaker failure) event poses a high risk and impact to the BES since it is a single Contingency event. The SDT raised the performance requirement on the P4 (stuck breaker) event for EHV to parallel that of the P2.3 event. The SDT considered that even though P4 is a multiple event, the design of the substation and Protection System can reduce the impact of events and the SDT believes that the standard should encourage designs that have a positive impact on the System's ability to serve Load. The SDT determined that the performance requirements for the P7 event for EHV should not be raised.		
Progress Energy Carolina (PEC)		PEC prefers having separate tables for steady-state and dynamic analyses. PEC believes the requirements were more clear in that format.
Response: The SDT consolidated the tables following several Draft 2 stakeholder comments to consolidate. The prior separate tables reflected the same planning events and the SDT agreed (although not unanimously) to consolidate for simplification. The column labeled "Fault Type" along with footnote 3 (now footnote 2) provides sufficient information regarding what is needed for the Stability analysis.		
City Utilities of Springfield, MO	No	City Utilities of Springfield, Missouri does not agree with the restrictions placed on the Category P3 contingencies. Since this will simulate a multiple contingency similar to a Category P4, loss of firm transmission service and/or loss of non-consequential load should be allowed. We suggest that the drafting team expand the allowable mitigating measures for a Category P3 to be consistent with a Category P4, where loss of firm transmission service and/or loss of non-consequential load is allowed for HV levels.
Response: The P3 Contingency (loss of a generator unit, followed by System adjustments follow by another N-1) was considered by the SDT as one of the more		

Organization	Yes or No	Question 9 Comment
likely planning events and therefore both the EHV and HV were kept to the more stringent planning performance criteria. No changes made for Draft 4.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican commends the SDT for most of the changes to Table 1. MidAmerican does have a few comments:? MidAmerican suggests that Footnote 11 be added to the sixth item under P4. The note 11 clarifies the meaning of a stuck breaker yet this footnote isn't applied to item 6 under P4 which is a stuck-breaker item. MidAmerican believes that it is confusing having a set of explanations for Extreme Events that are 1 through 3 under Steady State and 1 and 2 under Stability and yet have later footnotes listed that are 1 through 11. MidAmerican suggests that the items 1 through 3 under Steady State and 1 and 2 under Stability for Extreme Events be changed to some other designation such as bullets or letters so that it is easy to see that the numerical footnotes start after these explanations of the extreme events. ? Further clarify the applicable shunt devices in Footnote 7 with the suggested text 7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arrestors.
Response: The SDT accepts the proposed change to add a reference to footnote 11 (now footnote 10) on planning event P4.6. The SDT believes that the formatting is correct and sufficiently clear. No change made. Regarding the suggested change to footnote 7 (now footnote 6), the devices listed are not BES Facilities typically considered in a planning study. The SDT disagrees that the proposed change is needed for clarity. No change made.		
JEA	No	Footnote 8 relative to P2.1 seems to imply that all of the single contingency assessments for circuits should include assessment of (1) both ends of the circuit disconnecting as in P1 and (2) either end of the circuit disconnceting as in P2. This results in 3 seperate single contingency assessments for the one circuit. I am not sure of the benefit other than trying to identify a high voltage situation or in the case of tap loads, a thermal loading issue. Recommend changing Footnote 8 to"For circuits with tapped load, a seperate analysis shall be performed for an outage of each end of the circuit where the load is tapped."
Response: The SDT did not change the footnote since there are other conditions that may need to be evaluated for an open ended line such as angular Stability and high voltage.		
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	P6 on the table seems to be less severe than either P4 or P5, yet it allows loss of Firm Transmission Service and Non-consequential Load which are not allowed for EHV in P4 or P5. Interruption of Firm Transmission Service and Non-Consequential Load Loss should be allowed for P4, P5, and P6. Transmission lines should have the same requirements regardless of the voltage. Also, if not able to model Firm Transmission Service, how will one know if it is interrupted? The column labeled Interruption of Firm Transmission Service Allowed? should be eliminated since it is not a clearly defined test of

Organization	Yes or No	Question 9 Comment
		performance. It is not clear how to use the present definition of "Firm Transmission Service" for a planning horizon study. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV.

Response: The P6 event is considered a lower impact event since it requires two separate faults to occur. Therefore, interruption of Firm Transmission Service and Non-Consequential Load Loss following the second event is permitted. Conversely, the P4 and P5 events are based on a single fault and an abnormal clearing mode. These events pose higher risk and impact to the BES since there is no time for System adjustments for the multiple Contingency Facility outcomes resulting from a single fault. Therefore, the EHV is held to higher performance criteria. The SDT disagrees with the proposed change.

The higher expectation placed on the EHV, and therefore differing requirements for portions of the Transmission System, is due to the EHV being the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers.

The numerous Firm Transmission Service contracts occurring on a short-term basis within the operating horizon are not the focus in TPL-001-1. It is expected that any long-term Firm Transmission Service agreements required for consideration within a Transmission planning horizon will be limited and well known by the responsible entity. This has been further clarified in draft 4 per the revisions made to the Requirement R1 modeling requirements.

> **R1** Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use the latest data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions.

The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted.

> **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus

Organization	Yes or No	Question 9 Comment
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.

Response: The standard does not place a ceiling on DSM that can be utilized. No changes made in Draft 4.

Organization	Yes or No	Question 9 Comment
Progress Energy Florida, Inc.	No	PEF has multiple concerns with Table 1, the most fundamental of these concerns being that the existing Table in the existing TPL Standards is far superior to the new table. PEF suspects that the large blackout/brownout events in the Northeast and West have been the primary impetus behind devising a new Standard that will allegedly

Organization	Yes or No	Question 9 Comment
		improve BES reliability. PEF strongly feels that proper planning, operation and maintenance under existing NERC Standards could have prevented all of the aforementioned events, and thus a new TPL Standard and a new Table 1 is not necessary. PEF's specific concerns with Table 1 as it exists in this 3rd draft of TPL-001-1 are as follows: As a general concern, PEF, as has been stated already, does not believe that organizing a Reliability table according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is appropriate. The BES can be demonstrated to be robust and can even be continually improved under the existing TPL Standards. PEF fails to see how FERC's and NERC's desire to eliminate Footnote (b) as stated in the existing TPL Standards has anything to do with the desire to improve the reliability of the BES. Indeed, as TPL-001-1 exists at present, PEF suspects that many Transmission Owners will a) reduce posted ATC values to reduce risk of loss of Firm Transmission Service or b) remove breakers to convert Non-Consequential Load into Consequential Load. Both of these actions fly in the face of what FERC desires for the BES of the future. FERC certainly desires for power markets to open up further and thereby encourage lower energy prices, but at present TPL-001-1 and the accompanying Table 1 is in opposition to enhancing the power marketing industry. In addition, removing breakers is in opposition to reliability and customer service. An additional general concern involves the continued differentiation between HV and EHV. EHV by its very nature carries significantly larger amounts of power than HV, and therefore an EHV event inherently causes a greater disparity between Generation and Load than a HV event, making the loss of Firm Transmission Service or loss of Non-Consequential Load necessary for even a single contingency. Should all utilities be therefore required to make their EHV systems redundant? Such a suggestion is preposterous. Given this fact, and the fact that EHV events hardly ever occur (and, as outlined in the draft Table 1, have never occurred on PEF's system), PEF believes holding EHV to a higher standard is inappropriate, and will result in no more than a negligible reliability improvement at tremendous cost.Based on the above concerns, PEF believes for all event scenarios (P0 P7), analysis according to whether or not loss of Firm Transmission Service or loss of Non-Consequential Load can occur is inappropriate and should be deleted from the Standard. Concerning event P2-1, PEF assumes that "opening of breaker w/o fault" means opening breakers from both sides of the circuit. PEF therefore does not understand the difference between event P2-1 and events P1-1 through P1-4, and therefore suggests deleting P2-1 and combining the remainder of P2 with P1. Given the concerns above, voicing additional concerns about the Footnotes, short of reinstating the existing Footnote (b), is irrelevant.

Response: In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.

In Draft 3, footnote 8 (now footnote 7) was added to further clarify the need for the P2-1 event. The intent is simply to look for low voltage or thermal problems while supplying Load from one end of a normally networked line. In planning event P1-2, the network line would be opened at both ends and any Load tapped to the

Organization	Yes or No	Question 9 Comment
network line would be dropped. For planning event P2-1 for the same line, the Load would be studied being served from either end of the line.		
ISO New England, Inc.	No	Priority Comment As written, this requirement is overly severe. This would require the simulation of a "dead" station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. We also recommend that the Planning Coordinator be allowed to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.ii Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can't lose more than that permissible by the Planning Coordinator. Also change "pull out of synchronism" to "lose synchronism" in this sentence and in the second sentence. (Is "Lose synchronism" a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to ?A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower".

Response: In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description.

The suggested wording change to include "adjacent" for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

P7: Any two adjacent (vertically or horizontally) circuits on common structure

The SDT believes that the table is formatted correctly and is sufficiently clear. No change made.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive

Organization	Yes or No	Question 9 Comment
and the wording presently used, "pulling out of synchronism", is sufficient. Footnote 1 was deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made. The SDT accepts the proposed change for footnote 3 (now footnote 2). **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient evidence that a SLG condition would also meet the criteria. Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Arizona Public Service Co	No	P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4. We do not agree with Note "i" which requires establishing transient voltage response limits. There is no solid basis for such limits. In the past such limits were used as proxies for VAR margin and are not needed anymore. This will also result into non-uniform criteria throughout the interconnection. If such a limit were to be established, it should be based upon quantifiable reliably impact and should be supported by firm technical basis. Note 1b: Acceptable damping should not be defined by Planning coordinator and should be left to the Transmission Planner. Otherwise it would result into non-uniform criteria for the interconnections.
Response: The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus The SDT has added a Requirement R5 to explicitly require criteria for transient voltage criteria. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a		

Organization	Yes or No	Question 9 Comment
maximum length of time that transient voltages may remain outside that level. In regards to the comment on footnote 1b, as written it's based on the more restrictive criteria of the Planning Coordinator or the Transmission Planner. Since the Planning Coordinator has a wider area purview over the Transmission Planner, it is unclear why the commenter has a concern of Planning Coordinator criteria causing non-uniformity within the Interconnection. With fewer Planning Coordinators being involved there would be less disparity across an Interconnection if the Planning Coordinator's criteria were more restrictive than the Transmission Planner's criteria. No changes were made to this footnote in Draft 4.		
Hydro-Québec TransEnergie (HQT)	No	Footnote 4 We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying "and lower". As has been commented on in a previous draft, the Drafting Team should also consider not having a prescribed voltage definition of BES, be it called EHV or HV. Studies should determine what facilities should be part of the BES because of their impact on reliability. A proposal is to modify Footnote 4 to replace the phrase "(EHV) Facilities defined as greater than 300 kV" with "(EHV) Facilities defined as having a significant impact on the reliability of the System, generally at voltages greater than 300 kV as determined by the Planning Coordinator"? In using such language, the more stringent requirements could apply to BES/EHV but not globally for Facilities operating at voltages greater than 300 kV. Using this methodology the extra investment required would go towards real improvement of the reliability of the System. EHV and HV should be added to the Definitions of Terms Used in Standard. Footnote 12 We recommend adding an alternative modifier to the end of the sentence, "or for 5 towers or less. This is consistent with NPCC criteria.
Response: Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 4 (now footnote 3), the commenter suggests that the standard should not prescribe a voltage definition of BES, be it called EHV or HV and that studies are needed to determine BES Facility definitions. The BES definition is defined by the Regional Entity organization and studies are not generally relied upon for BES determination. The additional changes suggested in revising footnote 3 to limit the EHV definition to only those Facilities deemed significant to reliability as determined by the Planning Coordinator was not accepted by the SDT. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The EHV and HV definitions are not being added to the NERC Glossary of Terms based on their limited use within the TPL standard. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made.		

Organization	Yes or No	Question 9 Comment
Ameren	No	The word "Requirements" needs to be added to the Table 1 titles in the existing tables.Table 1 Steady State & Stability Performance RequirementsPlanning Events Table 1 Steady State & Stability Performance RequirementsExtreme Events Table 1 Steady State & Stability Performance RequirementsFootnotes (Planning Events and Extreme Events) Since it appears that the Table 1 cannot fit on a single page, it is suggested that multiple tables be developed to handle the 1) steady-state and 2) stability performance requirements. Footnotes may be included on a second page if needed. Comments were provided in early versions regarding the issues associated with raising the bar, and it was suggested that the marginal reliability benefits associated with these changes were not worth the marginal costs. We have not seen any significant changes from the earlier performance requirements. The question still remains, are we directing the resources where they need to be allocated to address and improve system reliability? So far the answer is believed to be "No".
Response: The Table 1 title does not include the word requirements since the table is referenced by the requirements of the standard. For example, see Requirement R3, parts 3.1 and 3.4 which require the Transmission Planner to develop Contingency lists for study based on the table performance requirements. The suggestion for multiple tables was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Maine Public Advocate	No	P2, P3, P4, and P5 - The change allowing no load shedding or interruption of firm transmission service for the types of events and faults listed will lead to the construction and installation of more transmission plant. These expensive plant additions have not, however, been preceded or justified by any evidence that the reliability of the current system - using current planning standards which allow load shedding and interruption of firm transmission service - is lacking. The August 2003 blackout, to the extent utilities and other industry stakeholders have cited it for this purpose, was not caused by the lack of such planning standards; it was an event that should not have occured and would not have but for the utter failure of First Energy to pay attention to operations and vegetation management. The Joint US/Canada Report makes this clear. These proposed changes are not needed and will cause unreasonable increases in rates that are not justified by the putative increases in reliability.There is currently too much emphasis on reliability and not enough emphasis on costs. Utilities are spurred, of course, by the FERC's ROE incentive. NERC should not allow this incentive to influence the reasonalbeness of any of its standards, particularly this one which can only lead to unneeded redundancy in the high voltage transmission system and resulting higher costs.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

Organization	Yes or No	Question 9 Comment
The P2 events are common failure, single Contingency events therefore the criteria is properly set. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined.		
Manitoba Hydro	No	Note b should be reworded to ?However, Supplemental Load Loss associated with a P2 through P5 event shall not be used to meet post-contingency steady-state performance requirements. Also we do not see a need for Load Reduction (see Q8 comment) Note b also implies that voltage dependent load is not permitted to be modeled for P0. This in turn means that the model must have all load represented as constant MVA. The load representation can change for categories P1 through P7. Is this the intent of the language? Note e: Are the planned System adjustments and redispatch allowed following all Planning Events if they result in curtailment of Firm Transmission Service? Should Note 10 also be referenced here? Footnote 7 applies to FACTS devices that are connected to ground. It is possible to have an ungrounded FACTS device (eg. Delta connected) or a series connected FACTS device (UPFC, SSSC, etc.). I would recommend deleting "that are connected to ground" so that the note is more general. Series connected FACTS will likely be separated via circuit breakers in a similar way as a transformer or phase shifter. Other series FACTS device, like a TCSC also typically self protect via a bypass breaker and should be considered as a separate element. Extreme Events:Steady State 1: Does the loss of a DC line refer to a bipole line? Steady State 2e: The loss of a large load could result from a Planning Event, perhaps even a P1 or P2 event - likely not an extreme event - compared to the loss of a major load center.
Response: The commenter provides no reasoning for the proposed limitation. No changes made. See our response to your Q8 comment. The standard does not prescribe a particular Load model such as constant power, constant impedance, etc. Footnote 10 (now footnote 9) does not apply globally to the entire table so it should not be reflected on header note “e”. No change made. The phrase “connected to ground” is appropriate since the focus is on shunt devices. No changes made. Loss of a bipolar line is covered as a P7 planning event. The reference to DC Line for the extreme event in question is intended to be loss of two independent single pole DC lines without time for System adjustments between each outage. The SDT has revised the extreme event descriptions for item 1 of steady state and Stability for clarity. **Extreme event steady state 1:** Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments. **Extreme event Stability 1:** With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced		

Organization	Yes or No	Question 9 Comment
out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments. While it is true that large amounts of Load could result from single Contingency planning events, the focus with the extreme event Steady State 2e item is different and intended to cover the complete loss of a major population center or urban area.		
E.ON U.S.		Table 1 Extreme Events CommentsSteady State2.bRight-of-Way should include a reference to footnote 1 2.2.d.Item 2.d. references loss of all generating units at a “station” but Item 3 references generating plants and nuclear power plants. It is unclear whether Item 2.d requires an outage of all generating units connected to a single transmission station (all voltages) or an outage of all generating units at a generating plant (although they may be connected to multiple transmission stations). 2.gRight-of-Way should include a reference to footnote 12. Footnotes12E ON U.S. suggests the definition be expanded to: Exclude circuits that share common structure for 1 mile or less and Transmission lines that share common Right-of-Way for 1 mile or less.
Response: The SDT does not believe a reference to footnote 1 is needed as suggested by the commenter. If the intent was to say a reference to footnote 12 (now footnote 11) as raised by other stakeholders, the SDT agrees with the proposed addition of a footnote to address a threshold distance for circuits considered for study in loss of common Right-of-Way. The team has set the threshold at 1 mile or more, consistent with footnote 11. Footnote 11 was revised to account for both the common tower and common Right-of-Way exemption. Footnote 11 has been added to the extreme event steady-state 2b. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less Extreme event 2d and 3a are similar in that each covers the loss of all generating units at a single plant location. However, in 3a, two plants are reviewed. In each case, all units are to be outaged regardless of the BES voltage level to which they connect.		
National Grid	No	Steady State & Stability comments are as follows:Steady State & Stability: a. Transmission voltage instability, cascading outages, and uncontrolled islanding shall not occur. How does this apply to Steady State testing?b. Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirementsThe second sentence re: Supplemental Load Loss implies need to test without end-user's actions and then assess whether action of separating end-user needs to be taken by Transmission system? B. Event P2-3 and P4 have the same impact; also events P2-4 and P4-6 have the same impact. Can these be consolidated? P5 Priority Comment ? As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. P7 Priority Comment Event 1 - This requirement requires the evaluation of the loss of two circuits on a multiple

Organization	Yes or No	Question 9 Comment
		circuit tower. We recommend that this be modified so that only the loss of two adjacent (vertically or horizontally) circuits need be evaluated. Or allow the Planning Coordinator to evaluate and if appropriate exempt specific locations from this contingency based on acceptable risk. Comments on Extreme Events Table 1- We recommend renumbering the Extreme Events table to be Table 2. Stability Condition 2 Note a - Priority Comment - As written, this requirement is overly severe. This would require the simulation of a “dead” station if only one battery is present (use of NERC Glossary Protective System definition is too broad). The failure of the single protection system should be limited to certain aspects of the protection system. Stability Condition 2 Note h Eliminate this requirement or change to loss of station following three phase fault. This note is confusing. Without providing a better defined scenario, it is unclear as to what clearing times should be used in this simulation. Note 1.a.i - For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism." There needs to be some sort of qualifier on this requirement. We suggest the following, "For Planning Event P1: No generating unit or units, directly interconnected at 100 kV or above, shall be allowed to lose synchronism." Note 1.a.ii “ Contingency Reserve is dependent on the generation on-line. We suggest changing the first sentence to say that you can’t lose more than that permissible by the Planning Coordinator. Also change “pull out of synchronism” to “lose synchronism” in this sentence and in the second sentence. (Is “Lose synchronism” a more commonly used term?). Note 3 We recommend revising the wording of the last sentence to “A 3 phase fault study indicating criteria are being met is sufficient evidence that a SLG condition would also meet criteria. Note 11. Reference is made to Independent Pole Operation (IPO) “ Can this be clarified by referencing it as IPO or Independent Pole Trip (IPT) as opposed to single-pole switching. Note 4 ? We recommend that a lower bound be put on the HV electric systems (such as 100 kV), rather than just saying “and lower”. Extreme Events:Steady State 3a - loss of two generating plants - This can be considered in two ways - one which results in loss of source (e.g. from fuel, cooling water, or nuke design shutdown) OR the second which could result in loss of stations including lines and breakers (e.g. from wildfires, weather, cyber attack, etc) - which is meant here? Both?

Response: The identification of Transmission voltage instability, cascading outages, and uncontrolled islanding is an appropriate expectation for steady state analysis. Steady state power flow analysis such as P-V or Q-V is suitable for screening, final System reinforcement decisions or operating limits are generally confirmed by more accurate time domain (dynamic) simulation. The TPL-001-1 standard in Requirement R5 requires the Transmission Planner and Planning Coordinator to define and document any criteria used to identify System instability such as cascading events, voltage instability or uncontrolled islanding.

The commenter suggests adding the word “Transmission” to the beginning of header note “a”. Additionally it is proposed to state in header note “b” that Load Reduction is not an acceptable means to meet steady state performance requirements. In Draft 4, the SDT made a change to header note “a” as suggested by the

Organization	Yes or No	Question 9 Comment

commenter but modified it to be “BES Transmission…”. Regarding the suggested change to header note “b”, no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. However, the definition of Load reduction has been deleted as it is now contained within the definition of Non-Consequential Load Loss.

The definition for Supplemental Load Loss was deleted and the definition of Non-Consequential Load Loss has been changed to reflect this.

> **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss and the response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment.

The commenter proposes to consolidate planning events P2-3 & P4 as well as P2-4 & P4-6 indicating they will have the same result. Within the steady state timeframe, these events will result in common outcomes; however, considered with the transient Stability timeframe, different outcomes are expected due to the delayed clearing mode of the P4 events. No changes were made by the SDT in this regard.

In regards to the P5 event, in response to industry comments on Draft 2, the SDT clarified that the P5 event is not intended to include an evaluation of individual components of the Protection System. The intent of P5 is to evaluate a failure of a Protection System design, and not based on any particular component of the design. Please see the Summary Considerations area of Question 7 from the Draft 2 comments; specifically item 3 on page 207. Since the P5 event description says loss of a single Protection System and not single Protection System device or component, the SDT believes sufficient clarity is inherent in the P5 event description.

The suggested wording change to include “adjacent” for the P7 planning event is accepted by the SDT and reflected in Draft 4. The SDT does not accept the proposed provision for the Planning Coordinator to exempt locations for study of the P7 event beyond what is already exempted per footnote 12 (now footnote 11).

> **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less

The suggested change to reference the extreme events as Table 2 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Regarding extreme event Stability item 2a, our response to your P5 comment above applies. No changes were made in regard to the extreme event 2a.

Regarding extreme event Stability item 2h, items 2f through 2h are deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The suggested change to reference the Footnotes area as Table 3 was not accepted by the SDT. The team feels sufficient clarity is provided by the division breaks within the table. The table is to be viewed holistically as a single table stating performance requirements and reference notes for the TPL-001-1 standard.

Footnote 1 has been deleted and moved to Requirement R4, parts 4.1.1 – 4.1.3. No change was made to the requirement wording as this standard only applies to the BES.

Regarding footnote 1.a.ii the SDT did not accept the proposed wording changes related to loss of synchronism. The change proposed was not substantive and that the wording presently used, “pulling out of synchronism”, is sufficient. Regarding the suggestion for the Planning Coordinator to establish the maximum allowable amount, the SDT has set a maximum and believes that it is the appropriate value. An entity can always set more stringent criteria. No change made.

The comment on footnote 1.a.i is redundant and already addressed above.

The SDT accepts the proposed change for footnote 3 (now footnote 2).

> **Footnote 2:** Unless specified otherwise, simulate Normal Clearing faults. Single line to ground (SLG) or three phase (3Ø) are the fault types, that must be evaluated in Stability simulations for the event described. A 3Ø or a double line to ground fault study indicating the criteria are being met is sufficient

Organization	Yes or No	Question 9 Comment
evidence that a SLG condition would also meet the criteria. Footnote 11 (now footnote 10) has been changed to address your concern. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing Regarding footnote 4 (now footnote 3), the SDT does not accept the proposed change to establish a lower bound on the HV electric System. The lower bound is based on the BES definition established by a Regional Entity organization. While this is generally understood to be 100kV, it may vary throughout the North American footprint. The SDT has however modified footnote 3 to include the text "defined by the applicable BES" to address the concern raised by the commenter. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load. Regarding footnote 12 (now footnote 11), the 1 mile exception is more precise as span lengths can vary greatly between towers. No change was made. For extreme event 3a, the minimum expectation is the loss of two entire generation plants due to some wide area event as described by the examples in roman numeral i through vi. The planner at its own discretion could simulate removal of Transmission lines, transformers, etc. for the initiating event scenario considered.		
Entergy Services, Inc	No	P2.1 should allow the shedding of load along the line that would be served radially to mitigate overloads or undervoltages on the radial line. Doing so would clearly not result in degradations to the BES but only the local area served by the radial line. P4.5 is an extremely unlikely occurrence and should be equivalent to P4.6. P5 should not be a planning event. PRC standards address Protection systems. The complexity associated with identifying and simulating such events is unknown and the defense of assumptions made and events simulated will lead to inconsistency in compliance and enforcement. Industry accepted proxies for such events could be developed that would allow for efficient identification of areas needing further detailed study. Attempting to intermingle protection system operation with BES performance will be nearly impossible to implement given current technologies. In general, the entire table should be reconciled, one way or another, with MOD standards governing ATC/AFC. If multiple contingencies, protection system failures, breaker failures, and other less likely events must be planned for, then ATC/AFC processes should be equally limited, at least for long term service. Any service granted on a simple N-1 basis should be Conditional Firm. Anything less than interconnection-wide application of more stringent AFC/ATC evaluation processes commensurate with the long term planning standards will result in the shifting of costs and risks from wholesale users to retail rate payers.
Response: FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		

Organization	Yes or No	Question 9 Comment
The likelihood of a bus fault is the same for each. However, the Bus-tie Breaker event (P4.6) has a lower risk simply because there are a limited set of Bus-tie Breakers compared to a entire population of BES breakers that could be in a stuck condition as in the P4.5 situation. No change was made in draft 4. The P5 the event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a delayed clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing. The comments made on the needed for reconciling the ATC standards are beyond the scope of this project. However, it is expected that conforming changes in other standards that currently reference the existing TPL standards will need to occur.		
Great River Energy	No	Why is the P needed in defining the category? They all have a P. Top note f and i should reference the Planning criteria established by the Planning Coordinator (or the Transmission Owner if more restrictive).The Transmission Owner is typically the one that sets the limits on their facilities. The Planner just works for the Owner.
Response: P is used as shorthand for "planning" event contingency as opposed to an extreme event Contingency. The Transmission Owner would establish the Facility Ratings, however, the Planning Coordinator and Transmission Planner establish the System criteria that must be met. Header notes 'f' and 'I' refer to established System parameters or criteria for voltage. No changes made.		
BC Hydro	No	Comments: Note "d": The term "Normal Clearing" is not well defined. Consider adding a definition in this standard or changing the NERC Glossary definition of "Normal Clearing" to read, "A protection system operates as designed and the fault is cleared in the maximum time that a properly functioning protection system would be expected to take to clear the fault, considering tolerances in normal protection operating times and circuit breaker interrupting times"No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System Note "e": Consider changing to, "For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are automatic (ie, implemented by a NERC-certified Special Protection System, SPS) and executable within the time duration applicable to the Facility Ratings. For P1 and P2 events, (a) generation shedding shall be limited to the normal level of Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) that would be carried in the control area under the system conditions being studied and (b) no manual operator actions should be necessary to ensure Facility Ratings are not exceeded. Note that, in the operating time frame, the operator would immediately take whatever actions and system adjustments are needed to prepare for the next set of possible contingencies". It should be recognized that this will result in a higher transmission planning standard than the previous wording and that should be seen as a desirable outcome of updating the NERC standards since transmission system reliability (or lack of it) is the impetus for the whole Mandatory Reliability Standards (MRS) process. It should also be emphasized that PLANNING standards are necessarily conservative, simple and easy to apply since in the planning time frame all possible circumstances that might be encountered in the operating timeframe cannot be

Organization	Yes or No	Question 9 Comment
		assessed or nothing would ever get built. If operator action is permitted "if such adjustments are executable within the time duration applicable to the Facility Ratings", how will that be measured consistently to ensure the standard is met? One planner might count on five operators having nothing to distract them from adjusting the output levels of 10 plants to reduce the load on a line to below its 10-minute overload rating, whereas another might be more conservative and assume some of the operators may be busy with other things and be more conservative in estimating how much can be accomplished in 10 minutes. If no operator action is permitted, the standard is easily measured and a more secure system results, one of the main objectives of the MRS. The addition of the requirement that criteria are met without operator action is consistent with R3.3.1 that states "[Contingency analysis shall] simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention [emphasis added]". Performance Category P7: Consider changing the first event to, "All circuits on common structures" and consider changing the fault type to 3-phase. Extreme Events (Steady State): Consider changing item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer is forced out of service. Extreme Events (Stability): Change item 1 to read, "With an initial condition of a single generator, Transmission Circuit, DC Line (one pole), shunt device or transformer forced out of service and prior to System adjustments, apply a 3" fault on a second generator, Transmission Circuit, DC Line (one pole), shunt device or transformer. Change item 2.g to read, "3" fault on all Transmission lines on a common Right-of-Way. Simultaneous 3" faults on all lines on a common right of way seems more likely (plane crash, avalanche, earth quake, wildfire) than simultaneous SLG faults. Footnote 1: Consider changing Item 1.a.I to read, "For Planning Events P1 and P2: No generating unit or units". And consider adding the following sentence, "No generating unit or units totaling more than the Contingency Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be disconnected from the System by a Special Protection System?. Footnote 8: Consider changing to, "Opening of Breaker(s) w/o fault in category P2 includes the situation in which one end of a normally networked Transmission circuit becomes open-ended, possibly resulting in voltage deviations outside acceptable limits especially at the open end of the line". Using the phrase "Opening of Breaker(s) w/o fault" that is used in the "event" column of category P2 will help people make the connection to the footnote.

Response: The SDT reviewed the existing NERC Glossary of Terms definition for Normal Clearing and found it sufficient for use in the TPL-001-1 standard. No changes were made.

Header note 'e' is not limited to automatic System adjustments. Manual operator initiated System adjustments are permitted so long as the applicable time limited rating is maintained during the adjustment. The proposed change was not accepted by the SDT.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 9 Comment</th></tr>
<tr><td colspan="3">
a) The standard does not place a ceiling on consequential generation tripping.

b) Manual operator actions are permitted for all Contingencies. The ratings must always be adhered to. If a Contingency were to cause current flows to exceed a 24-hour Facility Rating but a 4-hour rating was not, then either natural Load reduction or System adjustments must occur within the 4-hour period. The standard permits manual System adjustments. Requirement R3, part 3.3.1 only refers to the initial System reaction to the event that the simulation program must accurately represent.

The proposed changes to P7 were not accepted by the SDT. The situation described is covered as an extreme event under Steady State item 2a.

The proposed change of “DC Line (one pole)” over the existing text “DC Line” was accepted by the SDT with a slight modification to read single pole. Changes were made to items 1 for both extreme event Steady State and Stability.

Extreme event steady state 1: Loss of a single generator, Transmission Circuit, single pole of a DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, single pole of a different DC Line, shunt device, or transformer forced out of service prior to System adjustments.

Extreme event Stability 1: With an initial condition of a single generator, Transmission circuit, single pole of a DC line, shunt device, or transformer forced out of service, apply a 3Ø fault on another single generator, Transmission circuit, single pole of a different DC line, shunt device, or transformer prior to System adjustments.

Regarding extreme event Stability item 2g, items 2f through 2h were deleted as this was a mis-interpretation of the existing table and are not required in the Stability timeframe. The change proposed is no longer required.

The proposed change to footnote 1 was not accepted. Generation tripping by an SPS is permitted.

Footnote 8 (now footnote 7) was changed for clarity.

Footnote 7: Opening breaker(s) without a fault on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly serving Load radial from a single source point.
</td></tr>
<tr><td>IRC Standards Review Committee

Midwest ISO

Minnesota Power

New York Independent System Operator</td><td>Yes</td><td>The stability studies require significantly more computer time and a more detailed model. The standard should allow the PC/TP to use judgment to manage size and complexity of the study.</td></tr>
<tr><td colspan="3">Response: The standard permits judgment on choosing those events that are “expected to produce more severe System impacts.” See Requirement R3, part 3.4 and Requirement R4, part 4.4. Additionally, in this draft the SDT has removed extreme event Stability items 2f through 2h since this was a mis-interpretation of the existing table and are not required in the Stability timeframe.</td></tr>
<tr><td>PJM</td><td>No</td><td>Table 1, Lead in Note I. The industry has not yet reached a consensus on appropriate Transient Voltage Limits.</td></tr>
</table>

Organization	Yes or No	Question 9 Comment
		It's not clear that reliability will be enhanced by requiring each entity to establish a Transient Voltage Limit. Table 1 footnote 1 - System stable means: a. Angular Stability:i. For Planning Event P1: No generating unit or units shall be allowed to pull out of synchronism. A generator being disconnected from the System by fault clearing action or by a Special Protection System is not considered pulling out of synchronism.This is not consistent with Loss of load whereby load can be lost due to a first contingency within contractual arrangements made with the load. This definition should be modified to read -A generator being disconnected from the System by fault clearing action or by a Special Protection System or prior arrangement?- as long as no other cascading outages occur. In Table 1, Extreme Events, Item 3a, i, ii, iii, iv and vi seem like events that would occur over long periods of time not in contingency simulation time frames. They seem more like sensitivities. Table 1 Delete P5 is the preferred option. If not deleted need to clarify that so that related or additional -faults in the vicinity of- are considered. As currently worded it can require all simultaneous N-2 combinations within some number of substation radius for which overtrips could occur. You would have to do all combinations since they are unpredictable. If the SDT means for the relay failure to be located at or very near to the initiating event, then perhaps the combinations are more manageable but still extremely burdensome.
Response: The SDT has added new Requirement R5 to explicitly require criteria for transient voltage criteria. This new requirement allows for the responsible entity to determine the acceptable limit for its System. **R5** Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for their System. For transient voltage response, the criteria shall at a minimum, specify a voltage level and a maximum length of time that transient voltages may remain outside that level. The proposed change for "or by prior agreement" was not accepted by the SDT since the addition of footnote 5 (now footnote 4) and the ability to shed Conditional Firm service should adequately cover the situation described. No change made. The intent of extreme event 3 'a' is simply to look at the loss of all units from two separate plants. Items i, ii, iii, iv and vi are merely explanatory to what could initiate this type of event. No change made. The P5 event description was changed in Draft 3 to match what is stated in the currently approved TPL standards under Category C6 through C9. The intent of P5 is to evaluate a failure of a single Protection System design that introduces a Delayed Clearing mode that may also include additional electrical Facilities being removed when compared to normal fault clearing.		
Brazos Electric Cooperative	No	For the most part Table 1 is acceptable but not entirely. The general 'feel' is that more studies are required. Requiring more studies is not going to provide additional reliability benefit but Brazos does not own many miles of transmission above 300 kV so the impact will be less for us than other larger TOs. We do not see the purpose of studying events where all forms of load loss is allowed. We understand upgrading the transmission system for these events is not required and is unneeded so why study certain events other than to insure that cascading outages don't occur? Without running a full set of studies it is a little hard to determine if Table 1 can be readily assessed or the true value of the additional studies.

Organization	Yes or No	Question 9 Comment
Response: More studies are being required in the sense that sensitivity studies are now required. However, the number of scenarios covered in the planning events and extreme events is comparable to the existing Category A, B, C and D items in use today. For events that permit the loss of Non-Consequential Load, a Transmission Planner could elect to impose stricter criteria on itself than the minimum expectations of the standard. However, the SDT believes an appropriate criterion has been established. Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The sensitivity studies are intended to broaden the knowledge of the Transmission Planner. If several sensitivities show a susceptibility to a particular planning event, a Transmission Planner may elect to act and include in their Corrective Action Plans based on the risk and likelihood.		
American Electric Power	No	Consider adding a Planning Event defined to address common mode outages of two generating units. The language could parallel that of P7, substituting “common system” for “common structure”. In the present draft, Planning Events P4 and P5 address single faults that may result in multiple contingencies. Most of these events can be expected to involve either multiple transmission facilities or a mix of generating units and transmission facilities. P7 covers common mode (structure) outages of transmission lines. There are no common mode generator contingencies specified. Define the term “common Right-of-Way” and/or modify the term to “common or adjacent Right(s)-of-Way”. In the absence of a definition, if two lines are built on opposite sides of some geographic boundary (such as a two-lane road) they may legally be completely separate, potentially with no overlap in the agreements between the Transmission Owner and landowners. However, from the standpoint of BES exposure to weather related outages, the lines clearly will simultaneously be exposed to similar conditions. Lines that follow geographically parallel routes for more than a minimum distance and are within some minimum separation should be considered to be on a common Right-of-Way. Suggestion for the minimum parallel distance would be 1 mile (based on footnote 12).
Response: The common mode event described is classified as an extreme event, see item 1 in steady state and Stability. The Transmission Planner could elect to impose a higher criteria on itself and consider a variation of the P3.1 event that would not include a System adjustment between the loss of two units, but it is not required by the standard. No change made. The commenter accurately describes the potential outcome of the P4 and the P5 events. As described above, the Transmission Planner could elect to evaluate the simultaneous loss of two units, but it was not identified by data reviewed by the SDT as being a highly likely event and therefore not included as a planning event. The SDT has made clarifying changes to Footnote 12 (now footnote 11). Footnote 11 has been added to the extreme event steady-state 2b. Extreme event Stability 2f has been deleted. **Footnote 11:** Excludes circuits that share a common structure or common Right-of-Way for 1 mile or less		
LADWP	No	Table 1 continues with discriminatory performance criteria required of 300kV and above facilities. This new "higher" criteria could lead to endless argument and litigations as to who did what to whom if implemented. Currently, all transmission facilities have same performance criteria; the impacts of each new facility are carefully evaluated and mitigations are included as part of the Plan of Service. This new, discriminatory requirement would

Organization	Yes or No	Question 9 Comment
		force everyone with EHV facilities to re-do its palnning studies and mitigate the impacts. Unfortunately, the real world is quite messy. For example, Company A has put in a 500KV line twenty years ago and since then, Companies B, C, and D have put in several underlying 230 kV, 115 kV lines. Is company A on hook now to mitigate all the problems for lines that came in later? Or is it required to re-create the conditions 20 years ago and mitigate only what would have been required. This is a very simplistic example to illustrate potential disagreements that would arise by this discriminatory criteria. If there is any engineering evidence to support this arbitrary requiremnts, it has yet to be presented. As I commented in the past, the last two major cyctme wide cascading event, both in WECC AND THE Eastern Interconnect, were both caused by 230kV systems.
Response: Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. In the example provided, each company A, B, C and D is responsible for ensuring that criteria is met for its own facilities.		
Platte River Power Authority	No	At the top of Table 1 Planning Events, under "Stability Only:" regarding Note "i": Suggest deleting everything from "established" on to the end. (WECC establishes acceptable limits for transient voltage response.)
Response: The SDT has revised the referenced header note, now header note “k” in draft 4. The note now says both the Transmission Planner’s and the Planning Coordinator’s criteria must be met. **Header note ‘k’:** Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner.		
Orlando Utilities Commission	Yes	Comments: The table is significantly improved from the prior versions and provides superior clarification over the existing standards. In areas where an entity is the TSP and the PC, it is obvious that the Firm Service provided by the TSP falls within the performance requirements of the standard regarding curtailment. However if the firm service is provided by another TSP (a different PC) and causes a problem, who is responsible for insuring it does not have to be curtailed. As an example if System A has a firm transmission service agreement that under contingency causes a problem on System C, is system C in violation if the service has to be cut to protect their system, or is System A that granted and is responsible for the service?
Response: We appreciate your support of the TPL-001-1 standard and the revised Table 1. The Planning Coordinator or Transmission Planner is responsible for its portion of the BES and therefore is responsible for insuring there are no performance violations on its System. Further, the origin of the violation and the responsibility for curtailing service is not within the scope of the planning standards as it is an equity issue and not a reliability issue.		
American Transmission Company	No	We suggest the following changes:We believe reference to the use of Load Reduction to meet steady state performance requirement was omitted in Planning Events, Steady State and Stability, Item b. We suggest modifying the last sentence in Item b: However, Supplemental Load Loss and Load Reduction associated with an event shall not be used to meet steady state performance requirements. We propose limiting the scope to automatic devices in Planning Events, Steady State and Stability, Item c. We suggest text of: c. Simulate the removal of all elements that Protection Systems and other Controls are expected

Organization	Yes or No	Question 9 Comment
		to disconnect automatically for each Contingency?. Remove performance note ?e" in the Planning Events, Steady State & Stability section and replace it with R3.3.5 and R4.3.5, as suggested in the comments for R3 and R4. The qualification of allowable planned System adjustments should be a Requirement, rather than a performance note. Remove performance note "a" in the Planning Events, Steady State Only section, and replace it with R2.10, as suggested in the comments for R2. The obligation to identify and observe applicable steady state voltage and post-Contingency voltage deviations should be a Requirement, rather than a performance note. Remove performance note "b" in the Planning Events, Stability Only section and replace it with R2.10, as suggested in the comment for R2. The obligation to identify and observe applicable transient voltage response limits should be a Requirement, rather a performance note. Modify the P3 Category performance criteria to apply only to the loss of two generators because the probability of the loss of two base load generators is an order of magnitude greater than the loss of a generator and any other transmission element. We suggest the listing of: the loss of transmission circuit, transformer, shunt device, and single pole of DC line be removed from the P3 Events column. The corresponding events be moved to the P6 Category by "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column.Limit the scope of the simulations in Item 1 of the Extreme Events, Steady State and Stability section to automatic systems and controls. We suggest this text: "1. Simulate the removal of all elements that Protection Systems and controls are expected to disconnect automatically for each Contingency. Clarify the meaning of the loss of multiple circuits in Item 2.a of the Extreme Events, Steady State section by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common structure. Clarify the reference to actual, historical operating experience in Item 3.b of the Extreme Events, Steady State section. We suggest this text: "b. Other events based upon actual operating experience that may result in wide area disturbances. Clarify the reference to actual, historical operating experience in Item 2.i of the Extreme Events, Stability State section. We suggest this text that is similar to Steady State, Item 3.b: "i. Other events based upon actual operating experience that may result in wide area disturbances. Further clarify the applicable shunt devices in Footnote 7 with this suggested text: "7. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters. ATC suggest that following change to Table 1, footnote 4. Existing language:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems."Suggested Modification:"Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 100kV through the 300kV Systems."

Organization	Yes or No	Question 9 Comment
Response: Regarding the suggested change to header note "b", no change was made as the standard does not prescribe a particular Load model such as constant power, constant impedance, etc. The proposed change to header note "c" has been made. **Header note 'c':** Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. The proposed deletion of header note "e" was not accepted. The note is explanatory describing something that is permitted rather than a requirement that shall be followed. The proposed change to move item header note 'e' to the requirements was not accepted. Additionally, under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. Regarding comments on header notes "a" and "b" - under Requirement R3, part 3.1 and Requirement R4, part 4.1 the entire table is tied to a reliability requirement for both steady state and Stability. The loss of a generator plus any other N-1 item was viewed as highly likely by the SDT. No change was made to the P3 and P6 events as proposed by the commenter. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. No change was made to the note as the SDT considered the present wording sufficient to describe the condition. The proposed change to footnote 7 (now footnote 6) was not made as the SDT considers the present wording sufficient to describe the condition. The change to footnote 4 (now footnote 3) was not accepted although the SDT did make a clarifying change to the footnote. **Footnote 3:** Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as greater than 300kV and high voltage (HV) Facilities defined as the 300kV and lower voltage Systems as defined by the Regional Entity. The designation of EHV and HV is used to distinguish between stated performance criteria allowances for interruptions of Firm Transmission Service and Non-Consequential Load.		
Omaha Public Power District	No	Header note 'f' under Planning Events: The redline version shows that the sentence "Facility Ratings shall not be exceeded" was removed from the beginning of header note "f" (header note "b" in the previous draft). This sentence needs to be reinserted at the beginning of header note "f". The requirement that Facility Ratings not be exceeded is a core principle of steady-state transmission-system assessment and needs to be explicitly stated somewhere in the standard. If this sentence is not reinserted, it could lead to a situation where different regions come up with different interpretations of the manner in which Facility Ratings need to be respected. Category P2: In the third column of the table, there is a dotted line that appears to be separating two parts of the description for event type P2.3. It appears that this dotted line should be removed. Category P3: In the fifth, sixth, and seventh columns of the table, there is one set of cells for event types P3.1 through P3.4 and another set of cells for event type P3.5. Since these two sets of cells are identical, they can be merged into one set that applies to event types P3.1 through P3.5. This would make the presentation of requirements for Category P3 consistent with that of Category P1. Category P7: Category P7 requires analyzing SLG faults on any two circuits on common structures. Add language to clarify whether SLG faults on both the same and different phases of the two circuits need to be

Organization	Yes or No	Question 9 Comment
		considered or whether it is sufficient to assume that the SLG faults occur on the same phase of the two circuits.
Response: In header note "f", the text "Facility Ratings shall not be exceeded" was inadvertently deleted in the Draft 3 standard and has been re-inserted in Draft 4. The dotted line separator is appropriate and is used to distinguish between the EHV and HV performance criteria of the P2.3 event. The suggested table format change for the P3 event was accepted. The standard does not specify. It's at each Planning Coordinator's or Transmission Planner's discretion.		
Tucson Electric Power Company	No	Clarify use of the term "single contingency" in P2 as P2-2 and P2-3 are labeled as single contingencies but multiple elements are effected. In the past loss of a branch or shunt element has been considered a single contingency but loss of a bus element could involve the loss of multiple branch or shunt elements. P4: Under the event column it should clarify and state language similar to that of P5 (Loss of multiple elements caused by a stuck breaker). In addition, this is a multiple contingency condition and may result in loss of more than 2 elements. As such, this is a low probability condition and loss of Non-Consequential load should be allowed for EHV. We disagree with raising the bar for EHV for P4.We also disagree with raising the bar for P5. This is a multiple contingency condition and may result in loss of more than 2 elements. We strongly disagree with elimination of load shed (of non-consequential load) for loss of multiple branch or shunt elements >300 kV.
Response: The P2-2 and P2-3 items are considered single Contingency since a single fault occurrence causes the event. While it is true that multiple elements are anticipated to trip, the event is still considered a single Contingency. TPL-001-1 differs from the existing standard in that it is clear that single branch outages that are not reflective of actual Protection Systems and controls design will not be acceptable. If a single fault can result in multiple elements being removed from service they must be simulated accordingly. The SDT has added the introductory text proposed for the P4 "Event" column of the table to bring consistency with the P5 event. In regards to the EHV performance criteria for the P4 event, the EHV performance expectations remain as stated in Draft 3. P4 events pose higher risk and impact to the BES since there is no time for System adjustments for potential multiple Facility outages that can result from a single fault. Since the EHV is considered the backbone of the BES carrying large amounts of power between generation and Load and typically not directly servicing end-user customers the higher performance expectations for the high impact P4 events is warranted. **P4:** Loss of multiple elements caused by a stuck breaker [11](non-Bus-tie) attempting to clear a Fault on one of the following: & 6. Loss of multiple elements caused by a stuck breaker[10] (Bus-tie) attempting to clear a Fault on the associated bus Although not unanimous, the majority of the SDT and industry stakeholders believe the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the EHV breakpoint and the more stringent requirements are appropriately defined. The Implementation Plan is intended to provide sufficient time to shift to the new expectations.		
Independent Electricity System Operator	No	"Single-phase-to-ground" faults should replace all occurrences of "single-line-to-ground" faults.

Organization	Yes or No	Question 9 Comment
		Events in P6 and P7 need more clarity for back to back installation where no DC line exists. In note footnote 11 we propose the following change. 11. A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing. We do not agree with the removal of the provision to allow load rejection for 1 and 2 elements out of service under certain defined conditions as indicated in footnote "b" of Table I of the current TPL standards.
Response: The SLG fault description is a commonly understood term. No change was made. For back to back installations, each pole of the converter station would be treated the same as a DC line. No change made. The proposed change for footnote 11 (now footnote 10) was accepted. **Footnote 10:** A stuck breaker means that for a gang-operated breaker, all three phases of the breaker have remained closed. For an independent pole operated (IPO) or an independent pole tripping (IPT) breaker, only one pole is assumed to remain closed. A stuck breaker results in Delayed Fault Clearing In regards to proposed change to prohibit Non-Consequential Load shed in response to a single Contingency event, FERC, in Order 693, was clear in paragraph 1794 that interruption of Non-Consequential Load are not permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and the majority of the SDT support this position. The use of an SPS design would be permitted for a single Contingency event if the SPS design interrupts service to customers involved in an interruptible Load contract arrangement.		
ReliabilityFirst Corporation	Yes	The term "stuck breaker" has been mis-understood, and additional text is needed to make it clear. "A stuck breaker is defined as a breaker that failed to open due to a mechanical failure internal to the breaker which prevents it from opening or protection system failures that failed to send a trip signal.
Response: The SDT agrees in part with your response. We concur that a stuck breaker is based on a mechanical failure of a single breaker. However, a Protection System failure could result in different outcomes depending on the design implemented. The SDT has partitioned the prior C6 through C9 contingencies into the P4 and P5 planning events to bring greater focus on this distinction.		
Kansas City Power & Light	Yes	
ReliabilityFirst Corporation	Yes	
Dominion - Electric Transmission	Yes	
Duke Energy	Yes	
ITC Holdings	Yes	None

Organization	Yes or No	Question 9 Comment
New Brunswick System Operator		No comment
Gainesville Regional Utilities	Yes	
CPS Energy	Yes	
Southern Company	Yes	
Tampa Electric	Yes	
Response: Thank you for your response.		

10. The changes to the Table include the addition/revision of footnotes 5 and 10 that address curtailment of Firm Transmission Service and conditional Firm Transmission Service. Do you agree with the footnotes? If not, please provide specific comments.

Summary Consideration: The majority of respondents were positive with their comments on the addition of the two footnotes. A number of clarifying questions were asked and the SDT has attempted to quell those questions with clarifications made to the footnotes. Please note that footnote 5 is now footnote 4 and footnote 10 is now footnote 9.

Footnote 4: Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

Footnote 9: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 10 Comment
Dominion - Electric Transmission	No	Table 1 Interruption of Firm Transmission Service is not allowed for many of the events listed. Doesn't this imply that firm point-to-point service can't be interrupted even when the service is provided across points that are connected only by a radial facility? If so, does NERC have the authority to determine how transmission service providers calculate firm ATC? Dominion is also concerned that transmission service providers appear subject to "double jeopardy" I.E, NERC fine for violations of applicable reliability standard and FERC sanctions if OATT is violated.
Response: It is the SDT's opinion that the point-to-point service described is in essence; Conditional Firm Service based on the condition that the radial Facility is in service and could thus be interrupted under Footnote 5 (now footnote 4). No change made.		
Transmission Planning	No	It appears that the reference callout to footnote 5 should be placed on every "No" in the "Interruption of Firm Transmission Service column instead of in the header, as was done with reference callouts to footnote 10. In footnote 5 "conditional" should be capitalized since it refers to a specific product defined under the OATT. Also, this only covers the specific condition form of the product, but does not address the specified number of hours form of the product. If the second form of the product is the basis for the service and the transaction is modeled in the case, and curtailment will mitigate an overload, it should also be allowed. Footnote 10 is too long and subjective. There is no purpose in adding the phrase "when coupled with the appropriate re-dispatch of resources obligated to re-dispatch" because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative " no coupling necessary,

Organization	Yes or No	Question 10 Comment
		therefore, this phrase should be deleted. In addition, the last two sentences end in “must be considered”. What is the appropriate amount of “consideration” and what defines whether the consideration is acceptable or not? The last sentence should be a stand alone performance requirement in the Steady State and Stability notes at the top of Table 1 (in the list a through e) and should end in “must be adhered to” instead of “must be considered”.Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled “Initial System Conditions”) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load.
Response: Footnote 5 (now footnote 4) is intended to apply to every row in the “Interruption of Firm Transmission Service Allowed” column while Footnote 10 (now footnote 9) does not. The placement of the footnotes is predicated on that premise. No change made. The SDT agrees with the capitalization of the word Conditional and has made the necessary corrections. **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Footnote 5 (now footnote 4) states that “When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service…” The word “conditions” is intended to address the ‘hours’ form of Conditional Firm service in that the hours a service may not be available should be based on System conditions that exist for those hours. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC’s pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch is point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed. The SDT believes that applicable Facility Ratings noted throughout the standard cover all Facilities. No change made.		
SERC Engineering Committee Planning Standards Subcommittee	No	Footnote 5:Suggest rewording of footnote 5 to:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10: Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of

Organization	Yes or No	Question 10 Comment
		resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled “Initial System Conditions”) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be considered.
Ameren	No	Suggest rewording of footnote 5, though we do not use conditional firm service:Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service. Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line:Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled “Initial System Conditions”) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’splanning region are relied upon, Facility Ratings in those regions must also be considered.
Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9). **Footnote 4:** Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.: **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.		
SERC Engineering Committee Reliability Review Subcommittee	No	Suggest rewording of footnote 5 to: Curtailment of conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the conditional Firm Transmission Service.

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 10 Comment</th></tr>
<tr><td>(RRS)</td><td></td><td>Footnote 10 is definitely an improvement from previous versions. It is suggested that the word "also" be added to the last line: Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column titled “Initial System Conditions”) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be considered.</td></tr>
<tr><td colspan="3">Response: The SDT agrees with proposed re-wording of Footnote 5 (now footnote 4) and the additional wording in Footnote 10 (now footnote 9).

Footnote 4: Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

Footnote 9: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must should also be respected.

Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service.

Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions should also be respected.</td></tr>
<tr><td>Southern Company</td><td>No</td><td>Footnote 10 should not be applied to P3. The curtailment of firm service should not be allowed for a unit out / line out contingency.</td></tr>
<tr><td colspan="3">Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC’s pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made.</td></tr>
<tr><td>System Protection and Transmission Planning</td><td>Yes</td><td>These concepts seem too important to relegate to footnotes. Could this discussion of how to handle Firm transactions and redispatch be moved to a more prominent place? Perhaps these concepts should be removed</td></tr>
</table>

Organization	Yes or No	Question 10 Comment
Department		from this standard entirely. A more appropriate place for these concepts would be in ATC standards.
Response: While the SDT agrees that these are important concepts, given that the inclusion of all firm use of the BES, including the use created by Firm Transmission Service, is essential to meaningful Transmission Planning Assessments, The SDT therefore does not agree that the concepts can be removed entirely from the TPL standard. Ultimately Transmission planning engineers will be responsible for the study work done and the proposals to ensure each entity meets the requirements in the standard. The SDT believes that the tables will be the central point of reference and thus the most appropriate place for the provisions regarding how firm Transmission use can be handled. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	Excellent additionFootnote 10 is long and subjective. There is no purpose in adding the phrase “when coupled with the appropriate re-dispatch of resources obligated to re-dispatch” because if there is an obligation to re-dispatch, it is done, and if there is no obligation to do so, then curtailment is the only alternative “ no coupling necessary. Suggested revision:10. Curtailment of firm transmission service is allowed both as a System adjustment (as identified in the column titled “Initial System Conditions”) and as a corrective action, providing those adjustments do not result in the shedding of any firm Load.
Response: Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis.. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC’s pro forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made**.**		
FMPA	Yes	We disagree with how the performance criteria is applied to different contingencies, but agree that firm transmission can be curtailed post-contingency as a system adjustment, and especially as preparation for the next contingency.
NorthWestern Corporation NorthWestern Energy (NWE) (NWMT)	No	NWE has provided comments above concerning Firm Transmission Service and the foot notes should address the issues that we have raised above.
Progress Energy Florida, Inc.	No	Again, given the fundamental concerns that PEF has stated in previous Questions, PEF sees voicing detailed concerns for these footnotes as irrelevant, short of suggesting the reinstatement of the existing Footnote (b).
Response: The SDT thanks you for your comments.		
Progress Energy Carolina (PEC)	No	PEC believes that Footnote 10 should be clarified. The proposed wording "Where Facilities external to the Transmission Planner’splanning region are relied upon, Facility Ratings in those regions must be considered" is unclear. It is not clear what "relied upon" means. Also, thermal overloads on neighboring systems are generally

Organization	Yes or No	Question 10 Comment
		the neighboring system's responsibility to mitigate.
Response: The intent of Footnote 10 (now footnote 9) is to allow Transmission Planner's to use resources obligated to re-dispatch to meet reliability requirements. However, without due consideration to Facilities external to the Transmission Planner's study area, Facility Ratings could potentially be violated in those areas unbeknownst to the owners of those Facilities. Footnote 10 has been revised for clarity. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected.		
JEA	No	Footnote 10: First of all, the term firm Load is used instead of the term Non-Consequential load. Are these the same? If so, maybe we need to be consistent here. Assuming they are the same and in reference to previous comment on use of Non-Consequential load shedding. :"Propose establishing a cap on Non-Consequential Load Loss for all Corrective Action Plans where the Table 1 events currently do not allow at all. The cap could also be accompanied by an allowance of lag time (maybe 4-5 years)."To be consistent, some level of Non-Consequential load shedding should be allowed where Generation redispatch falls short for a few years until new planned generation is added to the system.
Response: The SDT does not see where any additional clarity would be added by the suggested change. No change made. The SDT has considered establishing a cap on Consequential and Non-Consequential Load Loss. Currently the SDT has elected not to do so, but instead to add reporting requirements in Requirement R2, Part 2.9 for a possible cap in the future. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
SMUD	No	The allowed corrective actions in Table 1 to meet performance standards do not explicitly state how DSM solutions should be treated [there is a potential for 20% of national peak demand to be met by "demand response"] . If it is allowed to be used, and since this is a fairly significant amount, it would help if it is explicitly addressed in Table 1.
Response: The SDT agrees that DSM initiatives can impact TPL-001-1 assessments. It is the SDT's opinion that DSM initiatives would be reflected in the Load models. No change made.		
Pacific Gas and Electric Co,	Yes	We support the concept. However, we are unclear about the last sentence of Footnote 10, which reads "where

Organization	Yes or No	Question 10 Comment
		Facilities external to the Transmission Planner'splanning region are relied upon, Facility Ratings in those regions must be considered. For resources from areas external to the Transmission Planner'splanning regions, would identification of the need to, for example, increase System Operating Limits into the his/her Transmission Planning Area as part of the Corrective Action Plan be counted as having "considered" the "Facility Ratings in those impacted regions"? Otherwise, it may be difficult for the Transmission Planner to assess and identify all the Facility Ratings that may be impacted in a region external to his/her Transmission Planning Area.
Response: The SDT agrees and has strengthened the language in Footnote 10 (now footnote 9) **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
Manitoba Hydro	Yes	Note 10: The drafting team is to be congratulated for including the ability to curtail Firm Transmission Service as long as generation is available to redispatch to prevent firm load loss. Note 5: Firm transmission service can also be curtailed when the service is conditioned on the element is being available (note 5). It is recommended to add note 10 to contingencies P1 and P2. This would allow for curtailment of Firm Transmission Service via redispatch without dropping load when re-adjusting the system following these single contingency events, or automatically adjusting the system via an SPS action initiated by the P1 or P2 event, consistent with note b of the existing TPL standards. The consequence of not including Note 10 could mean extensive new transmission line construction without any increase in transfer capability. In Note 10, the SDT is assuming that the Firm transmission Service is Network Service to load. Does Note 10 also apply if the Firm Transmission Service is firm point-to-point service?
Response: The SDT agrees that Footnote 10 (now footnote 9) all System adjustments. However, P1 and P2 do not include System Adjustments. While the SDT recognizes that firm service has been granted on radial Facilities it is the SDT's opinion that such service is, in essence, Conditional Firm Service based upon the condition that the radial Facility is in service. No change made. Footnote 10 (now footnote 9) was added to address the disjoint between how some parties calculate ATC/AFC when assessing Long Term Firm Transmission Service and the currently proposed TPL-001-1 standard. TPL-001-1 requires Transmission Planners to plan their systems to meet multiple contingency events and some parties assess Long Term Firm Transmission Service on a first Contingency basis. Units obligated to re-dispatch, as contemplated in Footnote 9 are those units which are contractually bound to provide the service as well as those obligated to provide the service under Network Integrated Transmission Service, under FERC's pro		

Organization	Yes or No	Question 10 Comment
forma OATT. Under the pro forma OATT, units designated as network resources receiving NITS are obligated to re-dispatch as requested by the Transmission Provider pursuant to Section 33.2 to maintain reliability. The footnote is worded such that curtailment/re-dispatch cannot result in the loss of firm Load preserves the guidance given by FERC in Order 693 that no single Contingency result in the loss of firm Load. No change made. Where contractual agreements exist between entities allowing re-dispatch, and the curtailment of Firm Transmission Service associated with that re-dispatch was point-to-point, the point-to-point service curtailment would be allowed. In the case of units otherwise obligated, namely those resources with Network Integrated Transmission Service designated as network resources, curtailment of point-to-point service involving those resources would not be allowed as there is no obligation to do so.		
National Grid Northeast Utilities	Yes	Capitalize “Firm Transmission Service” in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary
Northeast Power Coordinating Council	No	Capitalize Firm Transmission Service in footnote 10 and instead of saying firm Load use Firm Demand to be consistent with the NERC Glossary.
Response: The SDT agrees with the proposed changes. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must should also be respected.: Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled ‘Initial System Conditions’) and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must also be adhered to.		
BC Hydro	No	Comments: Consider changing Footnote 10 to read, “Curtailment of firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled [“title” is a noun, not a verb and “titled” is an adjective meaning having a title, esp. of nobility] “Initial System Conditions”) and a corrective action provided both are accomplished automatically by a NERC-certified SPS, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions must be considered.
Response: The SDT agrees with the proposed use of “entitled”. **Footnote 9:** Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed		

Organization	Yes or No	Question 10 Comment
both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources should be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must should also be respected. Curtailment of Firm Transmission Service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a System adjustment (as identified in the column entitled 'Initial System Conditions') and a corrective action, where it can be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Demand. Where limited options for re-dispatch exist, sensitivities associated with the availability of those resources must be considered. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be adhered to. The SDT respectfully disagree that inclusion of language limiting the use of Footnote 10 (now footnote 9) to only those applications where an SPS is involved would further complicate the application of the footnote and would unduly limit its application. No change made.		
San Diego Gas and Electric Co		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
LADWP	No	The use of the term"Firm Transmission Service" is problematic at best. See my comments on R1. The proper term is "Expected Transfer Level"
Response: Although Firm Transmission Service is a defined term in the NERC Glossary, it is recognized that some planning processes do not designate inter-area transfers as firm or non-firm. Re-dispatch of Designated Network Resources or resources contractually bound to participate in re-dispatch activities would in many cases result in changes in area interchange and thus would still be allowed in Footnote 10 (now footnote 9). Additionally, the proposed standard now requires sensitivities to be included in the Planning Assessment which may include expected transfers. No change made.		
Central Maine Power Company	Yes	
Independent Electricity System Operator	Yes	

Organization	Yes or No	Question 10 Comment
Kansas City Power & Light	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
MRO MRO NERC Standards Review Subcommittee	Yes	N/A
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	Yes	None.
Platte River Power Authority	Yes	
American Transmission Company	Yes	
Idaho Power	Yes	
Minnesota Power	Yes	
Midwest ISO	Yes	
NV Energy	Yes	
PJM	Yes	
Brazos Electric Cooperative	Yes	no comment
American Electric Power	Yes	
ITC Holdings	Yes	Comments: We concur that footnote 10 should not apply to P0, P1 or P2 events.
Entergy Services, Inc	Yes	Units obligated to re-dispatch must include all Network Resources
ISO New England, Inc.	Yes	
New Brunswick System Operator		No comment

Organization	Yes or No	Question 10 Comment
Western Area Power Administration	Yes	
MidAmerican Energy Company	Yes	
Deseret Generation & Transmission	Yes	
Gainesville Regional Utilities	Yes	
Western Area Power Administration	Yes	
Tampa Electric	Yes	
IRC Standards Review Committee	Yes	
TVA System Planning	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
FirstEnergy Corp	Yes	We presently agree with the Footnote 5 and text.
Response: Thank you for your response.		

11. The SDT has provided an Implementation Plan as part of this posting. The plan includes the retirement of TPL-005-0 and TPL-006-0. Do you agree with the elements of the Plan? If not, please provide specific comments.

Summary Consideration: There were 3 main comments associated with this question.

Eleven commenters indicated that 60 months is not enough time to build major lines, especially if up to 24 months is needed to do the Planning Assessment and develop a Corrective Action Plan. The SDT considered this issue when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of the comments received from this posting. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Eight commenters indicated that more time is needed before dynamic Load modeling Requirement R2, part 2.4.1 becomes effective. However, Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

Seven commenters raised concerns about the retirement of TPL-005-0 and TPL-006-0, regarding the requirements or lack thereof being placed on the Planning Coordinators and Transmission Planners to provide inputs to the Regional Entities so they can meet their obligations to NERC to prepare regional assessments. The SDT believes that the retirement of TPL-005-0 and TPL 006-0 have been adequately addressed by adding the Requirement R3, part 3.4.1, Requirement R4, part 4.4, and Requirement R8 with part 8.1 in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure.

Changes were made to the following requirements due to industry comments:

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

4.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.

R8 Each Planning Coordinator and Transmission Planner shall distribute its its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.

8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.

Organization	Yes or No	Question 11 Comment
Dominion - Electric Transmission	No	Dominion agrees with the retirement of TPL-005-0 and TPL-006-0. However, Dominion has some concern over the implementation period and believes that 60 months to implement corrective action plans may not be enough. This standard has more stringent requirements (“raising the bar”) than the current TPL standards. Having to assess the system for these new standards as well as implementing corrective action plans within 60 months could be difficult to get approval to site and construct new transmission. Dominion suggests that an additional 12 to 24 months be given to allow time for the assessments to determine violations, solicit input from all stakeholders through RTO process (As required by FERC 890) to determine the most appropriate corrective action plans.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft of TPL-001-1 does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: “If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control.		
Northeast Power Coordinating Council	No	Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. As written, the Standard would become effective at different times in different jurisdictions. Requirement R7 requires coordination among adjacent Planning Coordinators and any Functional Entity that has indicated a reliability need. Such coordination cannot be granted until the Standard is effective for all involved jurisdictions. The term "Planning Coordinator" is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the "Planning Authority" defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards. With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent

Organization	Yes or No	Question 11 Comment
		events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: Distribution of Planning Assessments under Requirement R7 (now Requirement R8) is not limited to Planning Assessment results produced in conformance with the revised standard. Until such results are available, the SDT intended that Planning Assessments produced using the existing standards would be distributed. Planning Coordinator is listed as the new term for Planning Authority in the latest approved version of the Functional Model and is in the latest version of the NERC Glossary of Terms Used in Reliability Standards. No change made. The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in response to single Contingencies simply reflects the existing practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
SERC Engineering Committee Planning Standards Subcommittee	No	Construction activities:60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.Dynamic load models:More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Bonneville Power Administration		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we've added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? OTHER COMMENTS:Would like to see TPL-001-1 more specifically address system performance required for radial load areas served by multiple transmission circuits (unequal capacity) from a single source substation. For

Organization	Yes or No	Question 11 Comment
		example, a radial load served by a single circuit 115-kV line and a single circuit 230-kV line. For a single contingency loss of the 230-kV circuit, cannot serve peak load area demand. Is this situation meant to be covered by Category P1 in TPL-001-1? I don't see anything similar to TPL-002-0a, Category B, Note b under Loss of Demand.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The loss of Load served by a single Transmission line would be considered Consequential Load Loss which is permitted by the TPL-001-1 standard. However, as in your example, if a Load is served by 2 Transmission lines and one of the lines is not sufficient to supply the Load for the loss of the other, then it would be considered Non-Consequential Load Loss which is not permitted.		
MRO MRO NERC Standards Review Subcommittee	No	MRO NSRS offers the following comments.The last paragraph should be removed from the Effective Date section. This paragraph contains requirements and describes compliance procedures, rather than stating effective date details. If any requirements regarding Corrective Action Plans are included, then they should be placed in the R2 section. If descriptions of compliance procedures related to Corrective Action Plan implementation are deemed to be necessary, then they should be placed in NERC procedure documents. This standard should not contain any requirements regarding the implementation of Corrective Action Plans. The implementation of transmission system action plans depends on the actions (e.g. financing, regulatory approval, legal services, engineering, construction, commissioning) of many different entities, other than PCs or TPs. So, PCs and TPs should not be held responsible for the implementation of action plans since they have little or no control over the activities related to implementation. The standard could include requirements that obligate PCs and TPs to develop Corrective Action Plans that are executable (i.e. plans that are based on lead times that provide reasonable assurance that the planned facilities can be placed in service by the time that they are needed) or devise revised Corrective Action Plans when they learn that the actions plans are not expected to be implemented by the intended in-service date. The standard could also include requirements that obligate PCs and TPs to establish and apply project implementation lead time assumptions that are derived from historical experience and the implementation lead time projections from the applicable TOs, GOs, and DPs. Remove or modify the 60 month effective date statement because it's impractical and unreasonable. The effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. This leaves only 36 months to expect that the more stringent Corrective Action Plans would be implemented. It is improbable that all action plans related to BES facilities, especially above 300 kV could be implemented. Some EHV projects can take 5 to 10 years to implement depending on the size, complexity, and controversial nature of the project. MRO NSRS suggests that the effective date be stated in a more "implementation dependent" rather than a "fixed timeframe" manner. Consider wording such as "tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans based on TPL-001-1 analyses are implemented".
Response: The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		

Organization	Yes or No	Question 11 Comment
The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The SDT considered your suggestion to change the language of Requirement 2.7.5 to make it more "implementation dependent" rather than using a "fixed timeframe" but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
SERC Engineering Committee Dynamics Review Subcommittee (DRS)	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. A 60 month effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
SERC Engineering Committee Reliability Review Subcommittee (RRS)	No	60 months after effective date seems generally acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting SERC member's bulk reliability during this construction period. Also SERC members are concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. SERC members are also concerned that the costs to meet the new requirements contained in this TPL will amount to many billions of dollars with very little impact overall on the reliability of the Bulk transmission system. "When will the Implementation Plan be removed from the standard after it is officially approved" Will a revised

<table>
<tr><th>Organization</th><th>Yes or No</th><th>Question 11 Comment</th></tr>
<tr><td></td><td></td><td>TPL standard need to be prepared to omit this implementation language??
If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?</td></tr>
<tr><td colspan="3">Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1 and Requirement R4, part 4.4.1 as well as Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.
3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.
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8.1 If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.</td></tr>
<tr><td>TVA System Planning</td><td>No</td><td>TVA is concerned that the 5 year window for meeting the "raising the bar" requirements is still not adequate. For instance, it typically takes TVA 7 to 10 years to build a new 500-kV transmission line - including time required for such processes as federally mandated NEPA environmental reviews. Strongly suggest increasing this time</td></tr>
</table>

Organization	Yes or No	Question 11 Comment
		window to 10 years.Also trying to construct enough facilities within the 5 year implementation period will result in multiple outages at same time - possibly affecting TVA's bulk reliability during this construction period. Also TVA is concerned that EHV equipment manufacturers will not be able to meet all the equipment orders that will be required to meet the "raising the bar" requirements. Thus TVA believes that these additional concerns strengthen the need to have a 10 year implementation period. Since breaker duty is a new "raising the bar" issue - should there also be a 5 year implementation plan for this as well? TVA is also concerned that the costs to meet the new requirements contained in this TPL will amount to between $1 billion to $2 billion with very little impact overall on the reliability of the Bulk transmission system. TVA is also very concerned about the increase in rates that will be required to support these new facilities. When will the Implementation Plan be removed from the standard after it is officially approved? Will a revised TPL standard need to be prepared to omit this implementation language? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.

Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply.

The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.

If manufacturers or other service providers can not meet increased demands for equipment and services, that would be an event outside the control of the Planning Coordinator or Transmission Planner.

The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related.

With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America's Bulk Electric Systems.

The Implementation Plan is not a part of the Standard per se but it will be balloted.

The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of "cross border" Contingencies and performance violations.

3.4.1 The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that

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FirstEnergy Corp	No	We disagree with the proposed Implementation Plan. The implementation period for the TPL-001-1 transmission planning standard should be limited to the time needed to transition to the new study requirements. The proposed 5-year implementation for the "raise the bar" aspects of this standard delves into project management and review of capital construction progress which should remain outside the scope of this standard. The standard should only consider if an entity has completed the required studies and has developed Corrective Action Plans to ensure performance criteria is being maintained. The last paragraph of the Implementation Plan is not appropriate for the Implementation Plan as it discusses compliance enforcement information. This paragraph should be srtuck.
Response: The SDT disagrees with your view that the Corrective Action Plans should not include implementation requirements. A plan has no value unless it is implemented. No change made. The SDT disagrees that the last paragraph of the Effective Date should be removed. No change made.		
IRC Standards Review Committee	Yes	The 3rd draft states this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Midwest ISO	Yes	The 3rd draft states that this will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
New York Independent System Operator		The 3rd draft states the Plan will be addressed later in the project. Removal of these standards would not affect NERC and the RE's obligations to perform assessments. The Standards Drafting Team should clarify whether the PC/TP will be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request.
Response: Retirement of TPL-005-0 and TPL 006-0 have been addressed by adding the necessary requirements in the fourth draft of TPL-001-1 to ensure that Planning Coordinators and Transmission Planners will provide the necessary inputs to the Regions so that the Regions can fulfill their obligations to NERC in accordance with the NERC Rules of Procedure. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that		

Organization	Yes or No	Question 11 Comment
Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
Southern Company	No	More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective.Other than that, the SDT has done a good job in allowing time for entities to get into compliance with the requirements where the bar has been raised.
Response: Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective.		
Lafayette Utilities System	No	Lafayette is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of “footnote b” in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that “raises the bar in several areas,” effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the “significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the

Organization	Yes or No	Question 11 Comment
		SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was “based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not “many” Transmission Owners” a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: “footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, “strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes “raising the bar” presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one’s fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.Lafayette asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, Lafayette suggests that, whether or not NERC chooses to stick with its 5-year “lowering of the bar” to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be

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		applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier “many” should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 “raises the bar” in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent “raising the bar”??
Louisiana Energy and Power Authority	No	LEPA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of “footnote b” in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that “raises the bar in several areas,” effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the “significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the ICT as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the ICT base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with

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		Standards rather than building the transmission projects that would have been required in accordance with the ICT base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO would even admit to this less reliable interpretation of footnote b. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. Hence, those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, have been rewarded at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and it has chosen to reject the ICT plan based on its own minority interpretation of footnote b. LEPA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, LEPA suggests that, whether or not NERC chooses to stick with its 5-year time period to permit those entities which may have used a similar interpretation of footnote b, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier "many" should not be

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		used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:"TPL-001-1 "raises the bar" in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent "raising the bar""?
Mississippi Delta Energy Agency	No	MDEA is in the area which is impacted by Entergy transmission planning. Entergy is one of the few NERC transmission owners which has for some years now relied upon its interpretation of "footnote b" in the previous TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0 as permitting planning for the loss of Non-Consequential Load or interruption of firm transfers as a way of planning and building less transmission than other utilities would have considered themselves obligated to build for reliability. That Entergy interpretation, and the consequent lower investment in transmission planning and construction, has been a matter of some concern among Entergy regulators at both State and Federal levels, as well as Entergy transmission customers, and has been rejected by the SPP, which has been given the authority to develop the base plan for transmission additions on the Entergy system. It was the Entergy rejection of that base plan that most recently led to a day long technical conference among regulators at the recent SEARUC conference in Charleston, SC.The proposed Implementation Plan for TPL-001-1 is drafted to make the new standard, which the proposed Implementation Plan describes as one that "raises the bar in several areas," effective only after the passage of 60 months from the first day of the first calendar quarter following applicable approval. That time for implementation is also embodied in A.5 of the proposed standard. This time lag is chosen, according to the proposed Implementation Plan, because of the "significant budget, siting, permitting, and construction impacts on many transmission owners. There are significant problems and costs for those whose electric service is dependent upon an inadequate transmission system, which would argue for a lesser period of time to reach compliance. This is especially true when the existing system is planned on an assumption as to the meaning of footnote b which assumption was clearly recognized as being controversial and a minority view. In recent years there have been repeated Entergy TLRs at quite high levels, which have repeatedly required emergency EEA-3s to keep firm load on line. And there has been an ongoing dispute between Entergy and the SPP as to footnote b and whether there should be limits on consequential load to be shed which has led the SPP (as the Entergy ICT) to have a complete base case for Entergy transmission construction already developed which is, by FERC direction, the basis for the Entergy construction plan. In its construction plan, however, Entergy dropped some 20 of the projects in the SPP base plan because of the Entergy view that it could go ahead and plan to drop non-consequential load as a means of remaining in compliance with Standards rather than building the transmission projects that would have been required in accordance with the SPP base plan. While not all of the proposed changes embodied in TPL-001-1 may have been incorporated in the

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		SPP base plan development, certainly the footnote b issues were. The costs of the failure of reliability and congestion resulting from the Entergy failure have been quite high, for Entergy retail customers as well as for others, and will continue to be high so long as there is no obligation to comply. Firm transmission obligations are simply not met while there is no obligation to comply. While it is certainly true that transmission cannot be planned and constructed overnight, it is also true that those who relied upon the minority interpretation of footnote b have been on notice for years both that that interpretation was challenged, and also that it was a minority viewpoint, as NERC itself advised FERC in its response to the NOPR that preceded Order 693.In 2007 FERC directed that NERC clarify the intended meaning of footnote b in its Order 693, and pointed out at that time that the interpretation permitting loss of load was "based largely on the matter of economics, not reliability. Id., P 1792. At that time, only Entergy and NIPSCO (certainly not "many" Transmission Owners? a word that appears twice in the draft Implementation Plan) would even admit to their interpretation of footnote b to weaken the grid. NERC agreed that such an interpretation was incorrect in its filings leading up to Order 693. In its June 26, 2006 Comments of North American Electric Reliability Council and North American Electric Reliability Corporation on Staff Preliminary Assessment, at p. 57-58, NERC noted that load shedding in a single contingency event is not acceptable: "footnote b to TPL-002-0 is intended to provide a limited exception to the general rule for serving load from a radial transmission line and should only be applied in unique circumstances, as described above. NERC recognizes that looped configurations are key to the reliable operation of the interconnection, and to meet reasonable expectations for reliable service to loads. . . . NERC standards, including footnote b, are not intended to endorse or approve planning the interconnection using radial configurations as a preferred method for reliably serving load, nor do NERC standards consider load shedding acceptable for single contingency events. It thus seems strange for NERC, an organization whose very existence was intended to assure the reliability of the grid, to reward those recalcitrant transmission owners who intentionally failed to expend the money and effort that the responsible transmission owners did expend, and at the expense of those who rely on the transmission system to do its basic job. Order 693, P 1794, "strongly discourage[d] an approach that reflects the lowest common denominator. Many of those transmission owners and planners for whom this change constitutes "raising the bar" presumably had plenty of time to consider what their options would be if their interpretation was incorrect, and should be expected to have reserve plans on hand pretty close to being ready to go when the dispute was lost. In the Entergy case, the plan has been in its hands for some time, and the fact that it has chosen to reject the SPP plan based on its own minority interpretation of footnote b is no one's fault but its own. And it certainly does not have to start from scratch to develop the plan; it consciously chose to reject the plan that the ICT developed for it.MDEA asks that at least as to the changes tied to footnote b interpretation, and other excuses for dropping non-consequential load, the time for compliance be shortened to no more than two years following regulatory approval of the standard. R2.6 already provides for the development of a Corrective Action Plan, and it would not encourage reliability if five years were taken to develop a Corrective Action Plan, as opposed to complying with the standard. Second, MDEA suggests that, whether or not NERC chooses to stick with its 5-year "lowering of the bar" to permit those entities which may have used a similar interpretation of footnote b to avoid building a sturdy grid, it not try to influence FERC and the courts as to legal questions that may develop during that period. We recognize that the changes made in what will be TPL-001-1 go well beyond the clarification of footnote b, so that for some changes there may be a reason for the 5 year phase in. But whether or not the 5 year phase in is going to be applicable to all of those changes, we suggest that it would be improper to mischaracterize what is being done in a way that

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		appears to have been drafted to influence legal questions that may come up.Specifically, as currently drafted, the descriptive modifier “many” should not be used in describing the entities which had chosen to use the lower bar interpretation of footnote b. While we recognize that a number of commenters have looked to one interpretation or another of footnote b in a few extreme situations, a review of comments does not show other transmission owners who have relied on the extreme interpretation used by Entergy on a systematic basis, And we think it inappropriate for the description in the paragraph beginning at the bottom of p.1 of that draft Implementation Plan to focus on the footnote b issue, as it now does. We suggest a modification which makes the description accurate, and which avoids the kind of misinterpretation which led to the footnote b controversy in the first place. We suggest that that first part of that paragraph be revised to read as follows:TPL-001-1 “raises the bar” in several areas where performance requirements have been changed in the new Standard versus those in existing TPL-001-0, TPL-002-0a, TPL-003-0a and TPL-004-0. Among other things, loss of Non-Consequential Load or interruption of firm transfers is no longer allowed for certain events, whereas the existing Standards were interpreted by some to allow such actions. As shown in Table 1 of TPL-001-1, the performance requirements associated with the following events represent “raising the bar”??
Response: Thank you for the background which helps the SDT understands your concerns. The SDT believes that this revised Standard has clarified the intent of the old footnote ‘b’ as well as other areas of the original standard that were open to interpretation. Standards must apply equally to all, so the SDT has chosen what it believes to be a reasonable implementation timeline that balances a wide variety of interests and circumstances. Finally, please note that the Implementation Plan document provided with this posting of the draft Standard is neither a part of the Standard or the Standard Roadmap but will be balloted. Therefore the SDT sees no need to modify the language.		
System Protection and Transmission Planning Department	Yes	We concur with SDT intent to retire TPL-005 and TPL-006. As there is no comment form entry to accept comments on MEASURES, we add one note here, related to "such as" lists - as noted above for R1.1.2, R2.1.4, R2.5.2, R3.3.4, R4.3.3, and R5. As written now, all measures include “such as” lists. We strongly suggest you remove “such as electronic or hard copies” from all measure statements.
Response: Thank you for your response. The SDT believes that examples of evidence “such as electronic or hard copies” help clarify the intent of the measure. Since no other responses requested removal of those words, the SDT will retain them.		
PacifiCorp Deseret Generation & Transmission SRP Southern California Edison Company Western Area Power Administration Pacific Gas and Electric Co, Puget Sound Energy, Inc.		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years?

Organization	Yes or No	Question 11 Comment
California ISO		
NV Energy	No	We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? Why is this changing from an annual reset period in the current standards?
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8.		
Tampa Electric	Yes	Consider having all requirements go into effect at the same time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made.		
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Overall the plan is an improvement! Allowing for a 60 month phase in of the more restrictive performance requirements is useful, however consider applying the 60 month phase in (or some timeframe) to P1 events for extenuating circumstances, e.g. unable to obtain ROW, etc. Having R1 and R7 going into effect first do raise the concern of what TPL standards are in effect during the time frame. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments where performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:"Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard"
Response: The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's		

Organization	Yes or No	Question 11 Comment
or Planning Coordinator's control. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made.		
FMPA	No	We suggest that the 60 month calendar apply to the HV system as well for all Categories. It is just as difficult, if not more difficult, to build a new 138 kV line in the Florida Keys as it is to build a 300+ kV line. The same time frame should apply to both. Also, as highlighted in the comments above to R2.1.4, P3 essentially causes utilities to build upgrades to N-3 planning criteria which may necessitate significant transmission upgrades if left unchanged. Hence, if left unchanged, P3 ought to have at least 5 years as well. The implementation plan ought to include an "out" for extenuating circumstances, e.g., unable to obtain ROW, etc. For instance, it is doubtful that another line in the Keys could ever get built without significant intervention and utilities that are unable to obtain ROW should not receive sanctions for something outside of their control. Consider changing the effective dates of R1 and R7 to take effect at the same time as R2 through R6 so you do not have to meet two standards during the same time period. Otherwise, clarify how the effective date impacts which version of the standard is to be used in an assessment before a scheduled compliance audit. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards effect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant. In this case that rationale would require that in the prior year two assessments were performed, one compliant with the current standard and one compliant with then new standard, however we don't believe that was the intent. Perhaps a statement below the paragraph regarding the 60 month implementation plan for Corrective Action Plans to the effect of:?Once effective all future assessments shall upon completion be compliant with this standard. Assessments completed prior to the effective date shall be based on the TPL standards in effect at the time. The standard is not intended to require a retroactively compliant assessment be in effect when the standard becomes active, but instead that the next assessment be compliant with the revised standard?
Response: The revised standard has raised the bar for certain planning events. In those cases, a 60 month effective date is permitted. The determination as to when the 60 month period applies is related to the Contingency and not the solution. Therefore, if a 138 kV line is proposed as a corrective action for one of the raising the bar events, 60 months would be provided to implement the construction of the 138 kV line. Regarding the impact of spare policies, the SDT does not agree with your premise that solutions to meet this requirement could take at least 5 years. Since the requirement addresses spare transmission equipment, and not generating equipment as your example suggests, one direct solution would be to purchase additional spare transmission equipment. In virtually all cases this could be accomplished in less than 5 years. The SDT believes that extenuating circumstances are covered in Requirement R2, part 2.7.5. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with		

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different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements. No change made		
Progress Energy Carolina (PEC)	No	More time than 12 months is needed for modeling the complete effects of Relay Protection Systems and the effects of Relay Loadability. PEC suggests that this period of time be extended to 24 months or longer.
Response: The standard does not require detailed modeling of Relay Protection Systems. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards.		
MidAmerican Energy Company	No	MidAmerican commends the SDT for its hard work on this standard. MidAmerican does not support the paragraph that states “Any entity that cannot fully implement its Corrective Action Plan”.shall self report itself?? MidAmerican believes that the Energy Policy Act of 2005 does not provide NERC or FERC the authority to require construction of facilities. Therefore, MidAmerican believes that this paragraph should be deleted in its entirety from the implementation plan as requiring responsibility to build facilities or else self report non-compliance. This is in direct contradiction to federal law.
Response: The Corrective Action Plan requirements do not necessarily result in construction of new Facilities, although it is understood that in some cases the only practical solution to a performance violation will require new or upgraded Facilities. Therefore, the SDT does not believe that these requirements contradict federal law and disagrees with your recommendation that the paragraph you mentioned should be removed.		
Northeast Utilities	Yes	Other Comments:Comment 1 Please clarify, since R2 through R6 should become effective before results could be distributed to adjacent Planning Coordinators and any functional entity. However, by the wording of the effective date of R1 and R7 it appears R7 becomes effective before R2 to R6. That is, 24 months are allowed by the standard to complete the planning assessments after regulatory approval. The results may not be ready for distribution by the planning coordinator after the first twelve months. Comment 2 The term “Planning Coordinator” is not defined in the NERC Glossary of Terms used in Reliability Standards and, therefore, this standard should indicate whether this term is the same as the “Planning Authority” defined in the glossary. Otherwise the definition of the Planning Coordinator should be included in the NERC Glossary of Terms used in Reliability Standards.
Progress Energy Florida, Inc.	No	While the Implementation Plan is extremely vague at present, making a specific enforcement date impossible to determine, PEF is concerned that the language at present will not allow enough time for Transmission Owners to prepare for the increased stringency.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have led to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. No change made. Planning Coordinator is defined in the latest approved version of the Glossary.		
Hydro-Québec TransEnergie (HQT)	No	With regard to the many changes/modifications from the previous draft and from the previous TPL standards being replaced by TPL-001-1, another posting of this Standard will be necessary to fully evaluate the impact (on

Organization	Yes or No	Question 11 Comment
		reliability and also cost of implementation) of such changes. The decision to allow the use of all type of RAS or SPS (particularly generator tripping and run-back) as a common practice for single contingency does not "raise the bar" in the planning standard, and should be reviewed. How can higher system performance be required that involves substantial infrastructure investment to prevent events with a very low probability of occurrence, and allow use of a less reliable measure (SPS failure or misoperation having a higher probability of occurrence) to reduce the investment for more probable events?
Response: The SDT agrees that another posting is required and has produced a fourth draft. The SDT's intent was to raise the bar where it was practical to do so and not lower the bar in any case. The allowance for the use of SPS and RAS in repose to single contingencies simply reflects the practice in many parts of North America. Where this has not been a common practice, individual Regional Entities, Planning Coordinators or Transmission Planners have the latitude to establish more stringent criteria.		
Ameren	No	At least 36 months would be needed for R1 compliance, should inclusion of explicit modeling of protection system equipment be required in dynamic model representations, and if all breakers would need to be explicitly modeled. More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. 60 months effective date seems acceptable for planning activities, but may not adequate for all construction activities. Typical times to construct a transmission line in various areas of SERC can range between 7 to 10 years. Accordingly, we recommend the effective date for construction projects be changed to at least 84 months. 12 months appears reasonable for R7.
Response: The standard does not require detailed modeling of Relay Protection Systems or circuit breakers. It only requires that the impacts of those systems be reflected in the modeling of Contingencies and the evaluation of the resulting System performance. This is no different than the current standards. Requirement R2, part 2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		
Manitoba Hydro	No	TPL-005-0 is a Regional and Interregional Self-Assessment Reliability Report. Such an assessment is beyond the capability of an individual PC or TP. While the new TPL-001-1 can and should include a requirement on the PC and TP to include in their assessments the interconnections with their adjacent systems, it does not make sense to

Organization	Yes or No	Question 11 Comment
		mandate an individual TP or PC to conduct an interregional assessment. Consequently, TPL-005-0 should be retained and mandated on the regions via the NERC delegation agreements with the regions.
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. It would require Planning Coordinators to provide the necessary inputs and work with the Regional Entity to provide a regional assessment that would continue to satisfy NERC's needs. The filing of a Planning Assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
Entergy Services, Inc	No	P1 events needs to be correctly classified as "raising the bar": P1 events should be included in the bulleted list of areas where the "bar was raised". The paragraph beginning at the bottom of page 2 of the Implementation Plan clearly states that the bar was raised "because loss of Non-Consequential Load or interruption of firm transfers is no longer allowed". Since P1 events in the existing standard allow this, the revised P1 events should be categorized as a raising of the bar. " Effective date needs to be extended: Additionally, in the areas where the bar has been raised, the effective date needs to be extended to at least 7 years. Siting (environment assessment and permitting, right-of-way acquition, regulatory approvals) alone for many of the facilities likely needed can take 3 years or more in some areas. Likely delays due to litigation and affected stakeholder intervention must be considered. In addition, while the SDT has collected some cursory estimates of the costs which may be passed on to end-use customers, no discussion of the intended or expected increase in reliability has been published. Other considerations that will have an impact on the effective date are construction outages on the bulk transmission system and competition of resources (human and material). " Effect on reliability is not adequately quantified: Since one of the SDTs objectives is to ensure that "requirements set at an appropriate level to ensure reliability,"what reliability metrics are expected to be impacted? By how much? What will the billions of dollars spent on transmission procure in terms of reliability to ratepayers? To what degree would the proposed standard decrease the probability of a blackout? If a blackout were to occur, would the proposed standard tend to decrease or increase the size and magnitude of the event?? More time is needed for entities to determine the appropriate dynamic load model required by R2.4.1. We recommend at least 36 months before this requirement becomes effective. Since breaker duty is a new "raising the bar" issue - should there also be a 5 or more year implementation plan for this as well? If a Transmission Planner has a Corrective Action Plan identified within the accepted time limitations but the facilities identified in the CAP cannot be implemented in time, would the TP be found non-compliant on the TPL-001-1?? If contingencies in one utility's system results in issues within another utility, who is responsible for studying the contingencies and who would be responsible for documenting the CAP?
Response: The SDT disagrees that P1 represents a raising of the bar. While the exiting standard was somewhat unclear about dropping firm Non-Consequential Load for P1 type events, there is little evidence to support that as a widespread practice. Therefore, the revised standard is simply a clarification of the intent of the earlier standards. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the		

Organization	Yes or No	Question 11 Comment
standard by potentially delaying some corrective actions that could be implemented in 60 months or less. The third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: “If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control. With respect to any additional capital requirements driven by the new standard, the SDT can not speculate regarding the magnitude of such requirements. However, the SDT strongly believes that the revised standard is necessary to ensure an adequate level of reliability for North America’s Bulk Electric Systems. Requirement R2.4.1 does not require a detailed dynamic Load model, only an aggregate System model. The SDT believes that such a model can be developed within the 24 month period before this requirement becomes effective. The SDT does not view the breaker duty requirements as a raising of the bar. While these may be new requirements in NERC Standards, the SDT believes that most entities already follow these practices because they are safety related. If a Transmission Planner has prepared an acceptable Corrective Action Plan within the required time limits, but the implementation of the plan cannot be completed in time for reasons that are beyond the control of the Transmission Planner, " then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. ….” In such a case, it is the intent of the SDT that the Transmission Planner would be compliant. The SDT has modified the language in Requirement R3, part 3.4.1, Requirement R4, part 4.4.1, and Requirement R8 with part 8.1 to clarify the handling of “cross border” Contingencies and performance violations. **3.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **4.4.1** The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. **R8** Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results. **8.1** If a recipient of the Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.		
PJM	No	Removal of these standards will not affect NERC and the Regional Entity’s obligations to perform assessments. Will the PC/TP be obligated under NERC Rules of Procedure to provide Assessments to NERC and the Regions upon request?
Response: The standard does not require an individual Planning Coordinator or Transmission Planner to conduct an interregional assessment. The filing of an		

Organization	Yes or No	Question 11 Comment
assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ITC Holdings	Yes	Comments: We generally concur. However, it would appear that there is no incentive to submit a mitigation plan for less than 60 months for the new requirements that raise the bar (those listed as bullet points). If "circumstances are within your control" to mitigate in less than 60 months, why not require it?
Response: While the SDT understands the basis for your suggestion, it would be cumbersome and possibly confusing to change the requirements to apply differently in different circumstances. The SDT believes that peer reviews of the Corrective Action Plan and compliance audits would incent completion of corrective actions as soon as practical. No change made.		
Northern Indiana Public Service Company	No	In A5, text appearing under "Effective Date" is not clear regarding application of the phrase, "(above 300 kV)", for the first and fourth dot points.
Response: For the first dot, the parenthetical "above 300 kV" applies only to P2-2 events. For the fourth dot, the parenthetical applies to all events P4-1 through P4-5		
LADWP	No	Cannot agree to something when this is not final.
Idaho Power	No	I would like to review this after completion of the standard.
Response: The SDT was simply asking whether you agree with the Implementation Plan as written.		
Orlando Utilities Commission	Yes	Overall the plan is excellent! Allowing for a 60 month phase in of the more restrictive performance requirements and an exception for those who need longer to meet them is an equitable and reliable practice. Having R1 and R7 go into effect first though raises the question of what TPL standard is in effect during that time frame? I recommend having the entire standard go into effect at the same time and avoid that issue. There is limited benefit to R1 and R7 going into effect early. The implementation should also be more specific on what "going into effect" means. Assessments are not a one day event but are a year long effort that culminates in a final "report" that is the assessment. Most NERC standards affect ongoing activities, and the day they go into effect the utilities functions are expected to be compliant, this is not however so clear when the "function" is the culmination of a year long effort. Perhaps a statement below the paragraph regarding the 60 month carve out to the effect of: Once this standard becomes effective all future assessments shall be compliant with this standard. Assessments completed prior to the effective date shall be judged by their compliance with TPL standards in effect at the time.
Response: The SDT chose a phased approach for establishing effective dates for individual requirements to reflect the broad range of implementation time frames associated with different requirements. Rather than use a least common denominator, which would have lead to a new standard that would not be implemented for 60 months, those requirements that needed less time were assigned earlier effective dates. The SDT recognizes that assessments take a period of time to complete. The date on which the assessment was initiated would determine whether the current TPL standards or the revised TPL-001-1 would govern compliance requirements.		
American Transmission Company	No	We offer the following comments.The proposed standard implies that the 24 and 60 month periods run in parallel rather than sequentially. As currently proposed, the effective date for performing analyses and developing subsequent Corrective Action Plans is 24 months. If the identification of new needs and action plans take 24 months, then only 36 months would be left to implement the new action plans. It may not be feasible to install some BES facilities, especially above 300 kV in less than 3 years. Some EHV projects can take 5 to 10 years to

Organization	Yes or No	Question 11 Comment
		implement depending on the size, complexity, and controversial nature of the project. We suggest that the effective date be stated in a more “implementation dependent” rather than a “fixed timeframe” manner. Consider wording such as “tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) is allowed until Corrective Action Plans that are based on TPL-001-1 analyses can be implemented”.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: “If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. ….” This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner’s or Planning Coordinator’s control. The SDT considered your suggestion to change the language of Requirement R2, part 2.7.5 to make it more “implementation dependent” rather than using a “fixed timeframe” but we do not believe such a change is appropriate because it would make auditing of this requirement difficult.		
Duke Energy	No	Requirements R2 through R6 are proposed to become effective the first day of the first calendar quarter 24 months after applicable regulatory approval, and we agree with that. However, the standard also provides that for 60 months following the first day of the first calendar quarter following applicable regulatory approval, Corrective Action Plans applying to performance elements P2-1, P2-2 (above 300 kV), P2-3 (above 300 kV), P3-1 through P3-5, P4-1 through P4-5 (above 300 kV), and P5 (above 300 kV) are allowed to include tripping of Non-Consequential Load or curtailment of Firm Transmission Service (in accordance with Requirement R2.6.4) that would not otherwise be permitted by the requirements of TPL-001-1. Since the first 24 months following regulatory approval will be spent developing and validating new studies and methodologies needed to meet TPL-001-1, that would only leave 36 months to implement corrective actions. We propose that the 60 month clock start with the effective dates of Requirements R2 through R6, to allow sufficient time to implement corrective actions that are determined within the 24 month period, which could include system modifications that require long lead times. Also, the implementation plan contains the following wording regarding retirement of the existing TPL standards: TPL-001-0, TPL-002-0a, TPL-003-0a, and TPL-004-0 are being retired as they are replaced in their entirety by TPL-001-1. TPL-005-0 and TPL-006-0 are being retired because their requirements are adequately covered by the revised TPL-001-1 and NERC’s Rules of Procedure, Section 800. TPL-001-1 should not be used as a vehicle for fulfilling any of the TPL-005-0 and 006-0 requirements because of the difference in focus and entities involved. In reality, the new TPL-001-1 does not appear to have incorporated any of the requirements of TPL-005-0 and 006-0. TPL-001-1 appropriately focuses on how PC’s and TP’s should perform studies and document assessments of their transmission facilities impact on BES reliability. TPL-005-0 and 006-0 focus on assessments of regional and inter-regional BES reliability, including other non-transmission issues as well. The NERC Rules of Procedure and existing FERC Order 890 efforts appear to be sufficient to cover the requirements of TPL-005-0 and 006-0.

Organization	Yes or No	Question 11 Comment
		Therefore, retirement of TPL-005-0 and 006-0 is still appropriate.
Response: The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT discussed its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control. The SDT believes that this revised standard together with NERC's Rules of Procedure will completely address the regional assessment requirements covered in the existing standards.		
Tucson Electric Power Company		We agree that TPL-005 and TPL-006 appear to have been adequately covered in the draft TPL-001-1 as currently written. However, we will need to review this assessment after TPL-001-1 is finalized. In addition, there is no place to state our concerns for Section D. so we added it here. We question the "not applicable" entry under Section D 1.1.2. What does it mean when the reset period is not applicable? Does it mean there is no reset period, so all non-compliance in all prior years will be counted as prior violations when considering non-compliance in future years? We believe that 60 months is not sufficient to implement the Corrective Action Plan for the "raise the bar" requirements. Siting transmission lines can take longer than this window. We strongly recommend increasing the window to 120 months which is a more realistic estimate of the time required to bring an EHV transmission project from conception to construction.
Response: The sanctions guidelines developed by the compliance program as part of the ERO start-up process eliminated the use of the concept of the "compliance reset period." The reason the heading "Compliance Monitoring and Reset Time" is still in the standards template is because some Standards Committee members felt that a change to the standard template couldn't be made without having the change go through full due process. Therefore, NERC staff agreed to always put, "Not applicable" under this heading until the next version of the manual is issued. This term will be eliminated in Version 8. The SDT considered the issues you raise on the sufficiency of a 60 month implementation window when TPL-001-1, draft 3 was prepared, and the SDT reconsidered its position in light of your comments and similar comments from others. The SDT believes that extending the 60 month implementation period would water down the standard by potentially delaying some corrective actions that could be implemented in 60 months or less. This third draft does in fact recognize the distinct possibility that major construction projects could take more than 60 months, in which case Requirement R2, part 2.7.5 would apply. The relevant portion of that requirement states: "If situations arise that are beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe, then the Transmission Planner or Planning Coordinator is permitted to utilize Non-Consequential Load Loss and curtailment of Firm Transmission Service to correct the situation that would normally not be permitted in Table 1, provided that the Transmission Planner or Planning Coordinator documents that they are taking prudent actions to resolve the situation. …." This provision could be applied when formulating the original Corrective Action Plan when it is known in advance that the permitting and construction process will require longer than 60 months or after the plan is formulated and unexpected delays arise outside the Transmission Planner's or Planning Coordinator's control.		

Organization	Yes or No	Question 11 Comment
Kansas City Power & Light	No	Regional areas may be made up of multiple Planning Coordinators. It is important to maintain an assessment of an entire Regional Reliability Organizations area. TPL-005 and TPL-006 should not be replaced with this proposed TPL-001.
Response: The SDT recognizes that many of the Regional Entities have multiple Planning Coordinators within their boundaries. The filing of an assessment by the Regional Entity is no longer required by a standard because it is covered adequately in NERC's Rules of Procedure.		
ReliabilityFirst Corporation	Yes	
Transmission Planning	Yes	
Pepco Holdings, Inc. - Affiliates	Yes	
Exelon Transmission Planning	Yes	
United Illuminating	Yes	
Western Area Power Administration	Yes	
Gainesville Regional Utilities	Yes, Yes	,
ISO New England, Inc.	Yes	
National Grid	Yes	
Brazos Electric Cooperative	Yes	no comment at this time
American Electric Power	Yes	
Minnesota Power	Yes	
Central Maine Power Company	Yes	
Response: Thank you for your response.		