NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Comments for 2nd Draft of Standard TPL-001-1 — Assess Transmission Future Needs (Project 2006-02)

The Assess Transmission Future Needs Standards Drafting Team thanks all commenters who submitted comments on the 2nd draft of reliability standard TPL-00101 — System Performance under Normal Conditions. The proposed standard was posted for a 45-day public comment period from August 14, 2008 through September 29, 2008. The stakeholders were asked to provide feedback on the proposed metrics through a special electronic Standard Comment Form. There were more than 80 sets of comments, including comments from more than 150 different people from more than 100 companies representing 8 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 the large number of comments received and the addition of VRF, Time Horizons, Measures, Data Retention requirements, and VSL, the SDT recommends an additional posting for this standard.

Due to industry comments, the following definitions have been changed: Bus-tie Breaker, Consequential Load Loss, Non-Consequential Load Loss, and Year One.

Due to industry comments, the following definitions have been deleted: Generating Unit Stability Study, Planning Coordinator, and System Stability Study.

Due to industry comments, the following definitions have been added: Load Reduction and Supplemental Load Loss.

Due to industry comments, the following requirements have been changed: R1, R1.1, R1.1.1, R1.1.2, R1.1.3, R1.1.4, R1.1.5, R1.1.6, R2, R2.1, R2.1.3, R2.1.3.4, R2.1.5, R2.2, R2.3, R2.4.1, R2.4.3, R2.6.1, R2.6.2, R2.6.2.1, R2.6.2, R2.7, R2.7.1, R2.7.1, R2.8, R2.8.1, R2.8.2, R2.9, R2.10, R3, R3.1, R3.2, R3.3, R3.3.1, R3.3.2, R3.3.3, R3.3.4, R3.5, R3.6, R5, R5.1, R5.2, R5.3, R5.3.2, R5.5, R5.6, R6, and R8.

Due to industry comments, the following requirements have been deleted: R2.1.4, R2.4.4, R2.5, R2.5.1, R2.5.2, R2.7.4, R3.4, R3.7, R4, R5.4, R5.5.1, R5.5.2, R5.5.3, R5.5.3.1, R5.5.3.2, R5.5.3.3, R5.7, R9, R10, R11, R12, R13, and R14.

Due to industry comments, the following table notes have been changed: Header note ‘b’, ‘e’, ‘i’, Footnotes 1.a.ii, 3, 5, 10 and 12.

The two table concept has been replaced by a single table with necessary corresponding changes to the notes and footnotes as appropriate. In addition, a typo in Extreme Event 2b was corrected due to an industry comment.

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.	Thad Ness	AEP	x		x		x	x				
2.	Anita Lee	Alberta Electric System Operator		x								
3.	John E. Sullivan	Ameren	x		x		x	x				
4.	Jason Shaver	American Transmission Company	x									
5.	Baj Agrawaal	Arizona Public Service Co.	x									
6.	Ronnie Frizzell	Arkansas Electric Coop. Corp.				x						
7.	James C. Armke	Austin Energy	x				x					
8.	Phil Park	BCTC		x								
9.	Eric Egge	Black Hills Corporation	x									
10.	J. David Carpenter	Brazos Electric Power Cooperative, Inc.	x		x		x					
11.	Paul Rocha	CenterPoint Energy and CPS Energy	x									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Glenn Pressler	City of San Antonio City Public Service (CPS Energy)	ERCOT	1

12.	David M. Conroy	Central Maine Power Company	x									

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
13.	Gary S. Brinkworth, P.E.	City of Tallahassee, FL	x		x		x					
14.	Karl Kohlrus	City Water, Light & Power - Springfield, Illinois	x		x		x					
15.	Marv Landauer	ColumbiaGrid										
16.	John Blazekovich (Exelon Corporation)	Compliance Elements Development Resource Pool (CEDRP)										
17.	John Loftis (Dominion Virginia Power)	Dominion - Electric Transmission Planning	x									

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Loftis		SERC	1
2.	Ronnie Bailey		SERC	1
3.	Peter Nedwick		SERC	1
4.	William Bigdely		SERC	1
5.	Mark Gill		SERC	1
6.	Larry Carter		SERC	1
7.	Mehdi Shakibafar		SERC	1
8.	Kirit Doshi		SERC	1
9.	Craig Crider		SERC	1
10.	Solomon Yirga		SERC	1
11.	Matthew Gardner		SERC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
18.	Greg Rowland	Duke Energy	x		x		x	x				
19.	Keith Yocum - Manger, Transmission Strategy & Planning	E.ON U.S. Transmission Planning	x									
20.	Dennis Malone	El Paso Electric Company	x		x		x					
21.	Charles W. Long	Entergy Services, Inc.	x									
22.	Jay Teixeira (ERCOT)	ERCOT System Planning		x								

Additional Member	Additional Organization	Region	Segment Selection	
1.	John Schmall	ERCOT	ERCOT	2

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
23.	Eric Mortenson	Exelon Transmission Planning	x		x							
24.	Sam Ciccone	FirstEnergy Corp.	x		x	x	x	x				

Additional Member	Additional Organization	Region	Segment

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

				Selection
1.	John Stephens	FE	RFC	1
2.	Doug Hohlbaugh	FE	RFC	1, 3, 4, 5, 6
3.	Don Morrison	FE	RFC	1
4.	Art Buanno	FE	RFC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
25.	Hector J. Sanchez	Florida Power and Light	x		x		x					

Additional Member		Additional Organization	Region	Segment Selection
1.	Bob Schoneck		FRCC	1
2.	Kiko Barredo		FRCC	1
3.	John W. Shaffer		FRCC	1
4.	Carlos Candelaria		FRCC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
26.	Richard Becker (FRCC)	Florida Reliability Coordinating Council, Inc										x

Additional Member		Additional Organization	Region	Segment Selection
1.	Ballard Keith Mutters	Orlando Utilities Commission	FRCC	3
2.	Rodney Hawkins	Lee County Electric Cooperative	FRCC	1
3.	Roger Allen Westphal	Gainesville Regional Utilities	FRCC	3
4.	Luther E. Fair	Gainesville Regional Utilities	FRCC	1
5.	Ted E. Hobson	JEA	FRCC	1
6.	Garry Baker	JEA	FRCC	3
7.	Donald Gilbert	JEA	FRCC	5
8.	W. R. Schoneck	Florida Power & Light Co.	FRCC	3
9.	Hector Sanchez	Florida Power & Light Co.	FRCC	1
10.	John Shaffer	Florida Power & Light Co.	FRCC	5
11.	Kiko Barredo	Florida Power & Light Co.	FRCC	1
12.	Ronald L. Donahey	Tampa Electric Co.	FRCC	3
13.	Gary S. Brinkworth	City of Tallahassee	FRCC	1
14.	Larry E Watt	Lakeland Electric	FRCC	1
15.	Bart B White	Florida Power Corporation	FRCC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
27.	Earl Fair	Gainesville Regional Utilities	x		x		x					
28.	Roger Champagne	Hydro-Québec TransÉnergie (HQT)	x									
29.	Milorad Papic	Idaho Power Company										
30.	Dan Rochester	IESO		x								

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
31.	Kathleen Goodman	ISO New England Inc.		x								
32.	Raymond Kershaw (ITC Holdings)	ITC Holdings: ITC, METC, ITC Midwest	x									
33.	Don Gilbert	JEA					x					
34.	Gary Newell (Thompson Coburn LLP -- Counsel to Lafayette Utilities System)	Lafayette Utilities System	x		x		x					
35.	Mace Hunter	Lakeland Electric	x		x		x					
36.	Larry Watt	Lakeland Electric	x									
37.	Sergio Garza	LCRA TSC	x									
38.	Tim Wu	Los Angeles Department of Water and Power	x		x		x					
39.	Kris Manchur	Manitoba Hydro	x		x		x	x				
40.	Tom Mielnik	MidAmerican Energy Company	x		x		x	x				
41.	Marie Knox	Midwest ISO										
42.	Spencer Tacke	Modesto Irrigation District	x		x		x	x				
43.	Tom Mielnik (MEC)	MRO NERC Standards Review Subcommittee	x		x		x	x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Neal Balu	WPS	MRO	3, 4, 5, 6
2.	Terry Bilke	MISO	MRO	2
3.	Carol Gerou	MP	MRO	1, 3, 5, 6
4.	Jim Haigh	WAPA	MRO	1, 6
5.	Charles Lawrence	ATC	MRO	1
6.	Ken Goldsmith	ALTW	MRO	4
7.	Pam Sordet	XCEL	MRO	1, 3, 5, 6
8.	Dave Rudolph	BEPC	MRO	1, 3, 5, 6
9.	Eric Ruskamp	LES	MRO	1, 3, 5, 6
10.	Joseph Knight	GRE	MRO	1, 3, 5, 6
11.	Joe DePoorter	MGE	MRO	3, 4, 5, 6
12.	Larry Brusseau	MRO	MRO	10

13.	Michael Brytowski	MRO	MRO	10			

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
44.	Carol Sedewitz	National Grid	x									
45.	Andrew Wilcox	NB Power Transmission	x			x						
46.	Patrick Brown (PJM Interconnection, L.L.C.	NERC and Regional Coordination		x								
47.	Gregory Campoli	New York Independent System Operator		x								
48.	James Manning	North Carolina Electric Membership Corp			x	x	x	x				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Bob Beadle	NCEMC	SERC	3, 4, 5, 6

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
49.	Rick White	Northeast Utilities	x									
50.	Guy Zito (NPCC)	NPCC										x

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Kiguel	Hydro One Networks Inc.	NPCC	1
2.	Ralph Rufrano	New York Power Authority	NPCC	5
3.	Dan Rochester	Independent Electricity System Operator	NPCC	2
4.	Rick White	Northeast Utilities	NPCC	1
5.	Lee Pedowicz	NPCC	NPCC	10
6.	Gerry Dunbar	NPCC		10
7.	Brian Hogue	NPCC		10
8.	Alan Adamson	New York State Reliability Council	NPCC	10
9.	Donald E. Nelson	Massachusetts Dept. of Public Utilities	NPCC	9
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Gregory Campoli	New York Independent System Operator	NPCC	2
12.	Chris De Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
13.	Brian Gooder	Ontario Power Generation Incorporated	NPCC	5

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
51.	Steven Masse	NSTAR Electric	x		x							
52.	John P. Mayhan	Omaha Public Power District	x		x		x	x				
53.	Greg Ward / Darryl Curtis	Oncor Electric Delivery	x									
54.	Matthew J Muldoon	OPUC									x	
55.	Aaron Staley	Orlando Utilities Commission	x		x		x	x				

Commenter		Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
56.	Chifong Thomas	Pacific Gas and Electric Co.	x									
57.	Sandra Shaffer	PacifiCorp	x									
58.	John Collins	Platte River Power Authority	x		x			x				
59.	John Cummings	PPL EnergyPlus					x	x				
60.	Mark Byrd	Progress Energy Carolinas	x		x		x					
61.	Bart White	Progress Energy Florida, Inc.	x		x							
62.	Tom Duane	Public Service Company of New Mexico	x		x							
63.	Joe Seabrook	Puget Sound Energy, Inc.	x		x							
64.	Herb Schrayshuen (SERC Reliability Corporation)	SERC Dynamics Review Subcommittee										x
65.	Herbert Schrayshuen (SERC Reliability Corporation)	SERC Reliability Review Subcommittee and Planning Standards Subcommittee										x
66.	Jessica Rice	Sierra Pacific Power Company/Nevada Power Company	x									
67.	Dilip Mahendra	SMUD	x		x		x	x				
68.	Dana Cabbell	Southern California Edison	x	x								
69.	Roman Carter	Southern Company Transmission	x									

Additional Member	Additional Organization	Region	Segment Selection	
1.	JT Wood	SOCO Transmission	SERC	1
2.	Jim Busbin	SOCO Transmission	SERC	1
3.	Shih-Min Hsu	SOCO Transmission	SERC	1
4.	Rod Hardiman	SOCO Transmission	SERC	1
5.	Randy Cobb	SOCO Transmission	SERC	1
6.	Chase Battaglio	SOCO Transmission	SERC	1
7.	Bill Botters	SOCO Transmission	SERC	1
8.	Tom Sims	SOCO Transmission	SERC	1
9.	Chuck Chakravarthi	SOCO Transmission	SERC	1
10.	Gary Gorham	SOCO Transmission	SERC	1
11.	Chris Wilson	SOCO Transmission	SERC	1

12.	Terry Coggins	SOCO Transmission	SERC	1
13.	Bob Jones	SOCO Transmission	SERC	1
14.	Raymond Vice	SOCO Transmission	SERC	1

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
70.	Brian K. Keel	SRP	x									
71.	Tacoma Power	Tacoma Power	x									
72.	Scott Helyer	Tenaska, Inc.	x									
73.	Dave Larsen	Transmission Agency of Northern California	x									
74.	Denise Koehn (BPA)	Transmission Reliability Program	x		x		x	x				

Additional Member	Additional Organization	Region	Segment Selection	
1.	Chuck Matthews	Transmission Planning	WECC	1
2.	Berhanu Tesema	Transmission Planning	WECC	1
3.	Kendall Rydell	Transmission Planning	WECC	1

	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
75.	Andy Leoni	Tri-State G&T	x									
76.	Mark Graham	Tri-State Generation and Transmission Association, Inc.	x									
77.	Gary Trent	Tucson Electric Power Company	x		x		x					
78.	B. David Till (TVA)	TVA System Planning	x									
79.	Karl Bryan	US Army Corps of Engineers, Northwestern Division					x					
80.	Jay Seitz	US Bureau of Reclamation					x					

1. **The SDT has modified the definitions and requirements associated with System Stability and Generating Unit Stability (formerly Plant Stability) in response to industry comments. Do you concur with the modified definitions for stability and, if not, please state why and/or suggest specific changes.**

Summary Consideration:

By a significant majority (about 2/3), the industry did not agree with the two definitions as modified in the second draft. Most of those disagreeing still express a fundamental disagreement with the approach of separating plant Stability from System Stability. Essentially many argue that plant Stability is simply a subset of System Stability, and the standard requirements could be simplified by focusing on Stability performance in a generic way. In this way Stability performance could be viewed in the context of individual units (generating unit Stability) or groups of units (System Stability). Some of these same commenters also argue that generating unit Stability is already covered by FAC–001 and -002 and, therefore, should be dropped from the TPL-001-1 standard; otherwise double jeopardy could apply. Many of these same commenters also suggested that if separation of generating unit Stability is retained in the final draft, then certain refinements of the requirements language should be made.

Others who voted 'No', as well as some who generally support the language of the current draft, recommended a variety of changes to the definitions and requirements for further clarity.

Only some 20+ percent of the commenters supported the current draft Stability definitions without reservation.

The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. Consequently, the two new Stability terms have been removed from the third draft, and this revised draft references the already approved term "Stability." Furthermore, as indicated by the SDT's response to commenters, the Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.

In summary, due to these and other industry comments in response to this question, the SDT has changed the following definition and requirements:

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

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~.

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

R2.2 For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

R3.3.1 (now 3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

- 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.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

Organization	Question 1:	Question 1 Comments:
NPCC	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one or more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
Los Angeles	No	Changing the name does not change the fact that this is wrong. The stability criteria in the standards are all measured on

Organization	Question 1:	Question 1 Comments:
Department of Water and Power		the high-side, i.e., the system side. So when a stability simulation is performed, if there is any problems, whether it be loss of synchronism, out-of-step, damping, inter-area oscillations, etc, they will all appear on the same run and there is no distinctions between system stability or unit stability. To separate the two implies there is a difference and requires two different simulations is either confusing at best or imply ignorance of the physics. Maybe the drafting team is concerned with the proper modeling of the generator in a stability simulation. There may be practice to "lump" similar units in a plant as one "unit" or the dynamic characteristics of a unit were not explicitly or correctly modeled; in such instances, the behavior of individual unit cannot be observed. But if that is the case, the entire stability simulation is incorrect to begin with anyway, even on the system side. To properly deal with unit modeling, the standard should prohibit lumping of units and require all dynamic data (including governor controls, exciters, stabilizers, etc.) are included in the simulation model.
National Grid	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
PacifiCorp	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Hydro-Québec TransEnergie (HQT)	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
CenterPoint Energy and CPS Energy	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. We (CenterPoint Energy and CPS Energy) remain unconvinced that the distinction is needed. If most industry commenters concur after this second draft, we believe the

Organization	Question 1:	Question 1 Comments:
		SDT should listen.
Austin Energy	No	There is no need to separate system stability studies and generating unit stability studies. Requirement R5.4 should be written to include generating unit stability analysis.
Tri-State Generation and Transmission Association, Inc.	No	Starting from this version, we think it would be clearer to not distinguish between generator and system stability studies, but rather list both as requirements for Stability Studies. Generating unit analyses would include tests of models such as generator exciters, and System Stability studies would model such things as bus faults.
Brazos Electric Power Cooperative, Inc.	No	We do not see the need to have 2 separate requirement sections nor definitions for both System and Generating stability studies. The section for stability studies should simply suggest when these studies should be performed, when new generation is added, conditions for that, etc? Confusion continues to come from the ambiguous use of language such as 'Material Transmission System changes' or 'changes in generation capability'. Of note in 2.5.2, requiring stability studies for the addition of a new substation in a transmission line connected to a generator is completely unnecessary most of the time but the wording in 2.5 does not appear to allow flexibility. Discretion should be provided to the TP.A first course of action would be to bring the related stability criteria under one section. It seems like 5.6 can be combined under a requirements section for stability studies.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes and No	We think we understand the direction that the SDT is heading but needs to be clearer. Angular stability for a single unit is the focus of Generating Unit Stability where as System Stability involves multiple generating machines or plants, and may also encompass voltage stability of loads which should be addressed separately in our opinion since different tools are used for this assessment.
ERCOT System Planning	No	Most industry commenters from the previous draft advised against making a distinction between system and generating unit stability, which are not commonly accepted industry terms. The only difference between the two seems to be location of contingencies tested. ERCOT suggests removing specific requirements for Generating Unit stability, as System Stability covers everything.
Central Maine Power Company	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should

Organization	Question 1:	Question 1 Comments:
		be stricken from the standard.
NSTAR Electric	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
New York Independent System Operator	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. Therefore, the definition of Generating Unit Stability Study should be stricken from the standard.
ISO New England Inc.	No	There should be no difference between System and Generating Unit Stability studies. Each requires discretion regarding which events need to be tested. The consequences are potentially similar: either the instability of one of more generators. Extreme Events should be considered for any stability analysis, again, recognizing that discretion needs to be applied when selecting or dismissing particular contingencies. If no distinction is made between System and Generating Unit Stability studies is made, then the definition of Generating Unit Stability Study should be stricken from the standard.
Entergy Services, Inc.	Yes and No	Entergy agrees with the intent. However, there will be some confusion because the industry standard terms for stability are omitted. It should be clear that the System Stability Study is a wide area view/assessment of both angular and voltage stability. In contrast, the Generating Unit Stability Study is focused on a specific unit or plant and the immediate area. Typically, this study looks at angular stability. The confusion may be exacerbated by the exclusion of a definition for voltage (or load) stability in the notes on page 31. There is a discussion of angular stability, but voltage stability is conspicuously missing. An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
BPA Transmission	No	Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the

Organization	Question 1:	Question 1 Comments:
Reliability Program		requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units.
Response: The SDT agrees and has modified the definitions and Requirements accordingly. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~. **R2.6.1** (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. 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. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5		
Progress Energy Carolinas	No	The System Stability Study definition could be improved by clarifying that it is a study that focuses on the impact of contingencies to the system itself and covers a larger geographical area than one Generating Plant. A specific proposal is as follows. System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular stability, inter-area power oscillations, and dynamic voltages.

Organization	Question 1:	Question 1 Comments:
Ameren	No	Agree with the revised definition of Generating Unit Stability Study. Propose new definition for System Stability Study, as follows - "Study that focuses on portions of the System, including the impact of contingencies on multiple generating units in an area. These studies would examine issues such as angular Stability, inter-area oscillation, and voltages during dynamic simulations."
SERC Dynamics Review Subcommittee	No	An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.
Southern Company Transmission	No	We suggest the following for the System Stability Study definition: Study that focuses on large portions of the System (which may include many generating units) and how contingencies affect that larger area to determine whether angular Stability is maintained, inter-area power oscillations are damped, and voltages during the dynamic simulation stay within acceptable performance limits.
American Transmission Company	No	Generating Unit Stability Study definition - We suggest deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - We suggest this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	There is an inconsistency between the defined terms “Generating Unit Stability Study” and “System Stability Study” and the usage within the standard. The requirements refer to these terms by omitting the word “study” .An improvement for the System Stability Study definition is to clarify that it is a study that focuses on the impact to the system itself and covers an area larger than one Generating Plant, covering a large geographical area. See specific proposal below: System Stability Study - Study that focuses on how contingencies impact a larger portion of the System than a Generating Unit Study. These studies would examine issues such as angular Stability, inter-area power oscillation, and dynamic voltages.?

Organization	Question 1:	Question 1 Comments:
Response: The SDT appreciates your suggested improvements. However, a majority of the Industry believes that there should be no distinction between System Stability and Generating Unit Stability.		
Platte River Power Authority	Yes and No	"Generator Unit Stability Study" assessments are applicable to FAC-001 and FAC-002. If specific requirements for a "Generator Unit Stability Study" are to be added to a standard, then those requirements belong in either a Revised FAC-001 or a Revised FAC-002 and not in a TPL standard. The "System Stability Study" assessments which are appropriate for TPL standards will capture both the performance of the system and the performance of specific generators at the various demand and stressed sensitivity levels studied.
BCTC	No	BCTC agrees with many other commenters, ABB, Ameren, Central Maine Power, NPCC RCWS, FirstEnergy, WECC, HQTE, Tenaska, FPL, FRCC, National Grid, New England ISO, NU, NStar, United Illuminating, BPA, Progress-Carolinas, TEP, and Northwestern Energy that there is no significant distinction between generator and system stability. These entities have significant experience with stability studies. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without any explanation. We believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by open access tariffs and FAC-001. This should not be duplicated in TPL.
Manitoba Hydro	No	Manitoba Hydro does not believe there is a need to distinguish between System Stability Study and Generating Unit Stability Study. Both these studies as defined require that synchronous operation of generators is maintained (i.e. angular stability) and damping is acceptable (i.e. small signal stability). The stability assessment would cover the issues being requested in the Generating Unit stability Study. We suggest the definition for System Stability Study - A study that determines whether angular stability is maintained, inter-area power oscillations are acceptably damped, and transient voltage swings remain within acceptable limits. Further, contrary to the SDT interpretation in the response to our first posting comments, Manitoba Hydro believes the Generating Unit Stability Study is a duplication of what is required in FAC-002-0 as the FAC requirements mandate system performance required by the NERC Reliability Standards. Manitoba Hydro continues to believe this additional study is redundant. Should the SDT decide to retain the Generating Unit stability study, then Manitoba Hydro recommends that, consistent with the wording in other requirements of this assessment section, it would be more appropriate to require that "Generating Unit Stability be assessed using current or qualifying past studies." This would allow use of current interconnection studies mandated by FAC-002-0 to be used to comply with the Generating Unit Study requirement. Currently, the wording in R2.5 requires that Generating unit stability be analyzed with studies for the conditions in R2.5.1 and/or R2.5.2.
Transmission Agency of	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is

Organization	Question 1:	Question 1 Comments:
Northern California		important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
OPUC	Yes and No	We cannot evaluate the need to distinguish generating unit stability and system stability without greater explanation inclusive of examples. We also need clarification of the intended interactions of this proposed standard with of FAC-001 and 2 to avoid duplication of efforts. Finally, if FAC-001 will cover generating unit or interconnection stability R 2.5 should clearly address existing older generators.
Pacific Gas and Electric Co.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not

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		need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Public Service Company of New Mexico	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Puget Sound Energy, Inc.	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit

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		Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Idaho Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to

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		say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SMUD	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Sierra Pacific Power Company / Nevada Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies? If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability.

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		Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequate addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Black Hills Corporation	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to "develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies". If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
SRP	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the

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		objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tucson Electric Power Company	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability

Organization	Question 1:	Question 1 Comments:
		problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Modesto Irrigation District	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study focuses on an individual generating units or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to “develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies”. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Tri-State G&T	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will

Organization	Question 1:	Question 1 Comments:
		operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
Southern California Edison	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection? to invoke a study.

Organization	Question 1:	Question 1 Comments:
Alberta Electric System Operator	No	We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1. In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say “only when” the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study.
US Bureau of Reclamation	No	Comments: We believe that there is no significant distinction between Generating Unit Stability and System Stability other than the objective and focus of the study. Therefore, we cannot accept a simple statement from the SDT that it believes it is important to maintain this distinction without more explanation. If a distinction is maintained, then Generating Unit Stability Study should be and is already covered in FAC-001-0 and FAC-002-0. As defined, Generating Unit Stability Study ?focuses on an individual generating unit's or electrically closely-coupled generating units' Stability for various Contingencies on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point. However, the Purpose of the proposed TPL-001-1 is to ?develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies?. If a Generating Unit becomes unstable, the unit can be disconnected from the BES without impacting system stability. Therefore, we believe that the Generating Unit Stability Studies portion is attempting to introduce interconnection stability studies into the TPL standards. Interconnection stability studies are adequately addressed by FAC-001 and does not need to be specifically called out in TPL-001-1.In addition, Generating unit stability studies are typically performed at the time of interconnection. Even though Generating Unit Stability Studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of Generating Units

Organization	Question 1:	Question 1 Comments:
		at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units or for the System. If the requirement for Generating Unit Stability Study is retained in this proposed TPL-001-1, R2.5 needs to be clarified to say "only when" the changes in R2.5.1 and R2.5.2 are made that the Generating Unit Stability Study needs to be done. There also needs to be language about how to treat generators that are existing prior to this Standard taking effect. We would also appreciate if the SDT would more clearly define with examples the terms in R2.5.2, "material Transmission System change" and "at or near the point of Interconnection" to invoke a study.

Response: The SDT disagrees with your view that generating unit Stability assessments should be covered in FAC-001 or FAC-002. The SDT recognizes that such studies are performed for new generator interconnection, following the requirements of the appropriate FAC Standards. However, the TPL-001-1 Standard is intended to ensure on-going assessments of generating unit Stability so as to capture any significant performance changes over the course of time. Nevertheless, the SDT has eliminated the distinction between generating unit Stability and System Stability by modifying the definitions and Requirements as shown.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~.

R2.6.1 (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

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.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and

Organization	Question 1:	Question 1 Comments:
R5.5.		
Gainesville Regional Utilities	No	Our small system does not have the present resources to deal with the large increase in stability type studies that this section seems to be requesting. Our system changes very little if at all from year to year. The ranking of the regional facilities where priority is given for stability study to the top 100 fault current buses shows that we do not have even a bus listed until position 611. We suggest that R2.4.1 should allow for only doing buses that have a ranking impact on the regional BES or no more that every 7 years for those systems without changes or are so small that their total separation or lost of their largest or almost total generation is not an issue for the RC. Stability should not have to be analyzed annually for small, unchanging systems.
Response: Where material changes do not occur as you describe for your System, studies would not have to be run any more frequently than once every five years, as described in Requirement R2.6 (now R2.5).		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	Requirement R 5.4.4: Consider changing the last sentence to the following: “If the Extreme Events analysis concludes there are widespread cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted.”
Response: The wording suggested is basically identical to what is already there. The SDT does not feel that this change provides any clarity or alters the context of the present text. Also, widespread is an ambiguous term and not measurable. No change made.		
Progress Energy Florida, Inc.	No	Progress Energy Florida, Inc. (PEF) does not believe that Stability Analysis should be or can be successfully divided into the proposed two distinct concepts of System Stability and Generating Unit Stability. Most textbooks dealing with the matter of Stability Analysis divide the issue into two parts, steady state and transient, and then subdivide the transient part into power angle stability and voltage stability. PEF has been unable to find any engineering treatise that argues for dividing transient Stability Analysis into System Stability and Generating Unit Stability. NERC's present definition of Stability, "The ability of an electric system to maintain a state of equilibrium during normal and abnormal conditions or disturbances", succinctly and correctly addresses the fact that stability issues regarding plants cannot be extricated from analysis of the rest of the system. PEF feels that this existing definition is accurate and not in need of clarification or improvement. To cite an example, if under the auspices of Generating Unit Stability, a transmission line trips, or if a load shedding scheme is activated, does the event then get defined as a System Stability event (or both)? It should be noted that the SDT attempted to both improve and clarify the definition of Stability in Note 5 of Table 2. The SDT's wording in Table 2 Note 5, while not containing any inappropriate or inaccurate information, has two fundamental flaws: a) it unnecessarily replaces the existing definition and b) it does not contain any language tying in the new definitions of System Stability and Generating Unit Stability. Furthermore, given that both of the new definitions are held to the exact same requirements, those found in Table 2, PEF can see no tangible benefit to two definitions, and therefore recommends removal of the new definitions of System Stability and Generating Unit Stability, and a return to the existing

Organization	Question 1:	Question 1 Comments:
		definition of Stability. Stability analyses that are taking place under the present definition and under the existing TPL Standards are more than adequate to demonstrate reliability of the BES, and PEF feels that the introduction of two new definitions would only serve to cause confusion and discussion regarding unmerited additional analyses.
Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, with these changes, the SDT believes that Note 5 of Table 2 has value to the Industry as a clarification of the existing Stability definition and should no longer be viewed as a replacement definition. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~. **R2.6.1** (now 2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now 2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. 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. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5		
Lafayette Utilities System	No	Lafayette Utilities System (Lafayette) does not dispute the need for stability studies, especially in connection with significant system topology changes. We are concerned, however, by the possibility of inconsistencies between the results of interconnection studies conducted for new generating units pursuant to the Large Generator Interconnection Procedures prescribed by FERC and Generating Unit Stability Studies conducted as part of the TPL-001 planning assessment. For example, if a TPL-001 stability analysis indicates the need for more costly or extensive transmission upgrades that were indicated in an earlier LGIP interconnection study, the generation developer could be placed in an

Organization	Question 1:	Question 1 Comments:
		untenable situation: it would have proceeded with its project based on the assumption of responsibility for LGIP-indicated upgrades, but then could face demands for the funding of additional upgrades pursuant to the TPL-001 stability analysis. Improved integration between the two sets of stability studies appears warranted, in order to avoid placing generation developers in this position.
Response: The SDT understands your concerns; however, we believe that TPL-001-1 will not create an untenable position for generation developers following the LGIP. Studies to interconnect the generator in accordance with the LGIP will identify those Facilities to be incorporated in the Interconnection Agreement. Future studies carried out in compliance with TPL-001-1 will ensure on-going System reliability, and any Facility upgrades required for that purpose will be the responsibility of the Transmission Owner, not the generation developer.		
Arizona Public Service Co.	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
ColumbiaGrid	Yes and No	We generally concur with the changes for the Requirements associated with the Generating Unit and System Stability, however, Generating unit stability studies are typically performed at the time of interconnection. Even though stability studies have been done as new generating unit(s) were interconnected or at the time changes occurred, such studies have not been done for the entire fleet of generating units at the same time. For very old units, stability study documentation may no longer exist, even though no potential stability problems have been identified when stability studies were run for interconnecting other newer units. Will every TP have to benchmark their generating unit stability study for its entire fleet with the acceptance of this Standard? In other words, will every TP has to recreate documentation for all its older units?? We would appreciate that the SDT more clearly define the terms in R2.5.2, “material Transmission System change” and “at or near the point of Interconnection” to invoke a study with examples.
Response: The SDT believes that the modified definitions and Requirements in the third draft address your concerns. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~		

Organization	Question 1:	Question 1 Comments:
R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. 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. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5 Specifically, as to your question regarding "benchmarking," the revised requirements would not necessitate studies of each individual generating unit or generating plant.		
Florida Power and Light	No	This draft did not modify the existing NERC definition of Stability. Footnote 5 of the Tables describes the expected acceptable performance of a System that is stable, but the terms "System Stability" and "Generating Unit Stability" are not defined, except as studies. All stability studies must meet the Performance Requirements for Planning Events in Table 2 - Stability Performance. If there were different Performance Requirements then the distinction may be warranted. However system stability studies should be sufficient and not warrant additional work. R6 requires Transmission Planners to define proxies used to identify instability. Presumably the "proxies" would be used as a checklist for assessment of stability; however, not all stability limitations can be simplified as a proxy in the load flow. Proxies should only be used as indicative of a potential stability issue, not "to identify System instability", or replace stability studies, since a stability study to identify the issue was initially required to define the proxy. The requirement should be reworded to state "R6. If proxies are used in simulation studies to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding, then each Transmission Planner and Planning Coordinator shall define the proxies used in the simulation studies."

Organization	Question 1:	Question 1 Comments:
Orlando Utilities Commission	No	I support the comments from Florida Power & Light regarding System Stability vs. Generating unit studies and proxies.

Response: The SDT agrees and has modified the definitions and Requirements accordingly. Furthermore, the SDT has also modified the wording of R6 to address your concern.

R2. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~.

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.

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.

The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.

R6. Each Transmission Planner and Planning Coordinator shall define and document, within their Planning Assessment, ~~the~~any proxies used in ~~simulation studies~~ the analysis to identify System instability for conditions such as cascading outages, voltage instability, or uncontrolled islanding.

Organization	Question 1:	Question 1 Comments:
Exelon Transmission	Yes and No	The definitions of System Stability and Generating Unit Stability are clear. We agree that there is value in performing small signal analysis but we are concerned about the availability of software and expertise required to execute the

Organization	Question 1:	Question 1 Comments:
Planning		analysis.R5.3 is ambiguous, as it is not clear what the requirement to consider the voltage ride through capability of all generators entail. Ride through could involve the unit or station having the capability to ride through without tripping or the unit could trip but the system remain stable. General Observations R3.2.1 should be reworded so as not to be misinterpreted that GOs are prescribing their 'required' voltage levels. R2.6.2 should be Unit not Plant with regard to stability studies. R2.7.1 and elsewhere - The NERC Glossary specifies that SPSs are 'Special Protection Systems' (not 'schemes'). R5.2 Wording should be changed from '...disconnect for each contingency..' to '..isolate the disturbance... .' R5.5.1 There are too many studies required. The 20 MW threshold for unit studies may be too low. There should be a mechanism to provide a proxy for smaller units on 138 or possible 230 kV systems that can't affect system stability rather than to automatically require a study every 5 years. R2.1 and 2.2 should have the words 'at a minimum' removed with regards to describing which studies are required annually. The requirement to supply a 'project initiation date' for near-term Corrective Action Plans should be removed. If it remains, it should be clarified (Project identification date, construction start date, PUC certification date, executive approval date, etc?)

Response: The intent of Requirement R5.3 is to ensure that the generating unit models realistically replicate the behavior of the generator in response to a low voltage condition encountered during the simulation.

The requirement on voltage ride through has been changed to provide clarity (now R4.3.2).

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

The SDT has deleted the distinction between Unit/Plant and System Stability based on other comments.

The SDT agrees that SPS means “Special Protection Systems” and the third draft uses this terminology consistently.

The SDT disagrees with your suggested rewording of Requirement R5.2 because the concept that the requirement is addressing relates to the resultant topology of the system after the fault is cleared and not the removal of the disturbance.

In response to your comment on Requirement R5.5.1, the SDT believes that all of the studies needed to satisfy this requirement are essential to maintain reliability. The SDT has thoroughly debated the 20 MW generating unit threshold and continues to believe that this is the appropriate value.

In Requirements R2.1 and R2.2, the SDT has removed the words “at a minimum” as you have suggested.

Organization	Question 1:	Question 1 Comments:
R2.1 The Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported ~~at a minimum~~ by the following annual current studies, supplemented with qualified past studies as indicated in Requirement R2.6: **R2.2** For the Long-Term Transmission Planning Horizon portion of the steady state analysis, ~~at a minimum,~~ a current System peak Load study is required annually for one of the years in the assessment period to support the annual Planning Assessment. In response to your comment on "project initiation date," the SDT considered your suggestion; however, the SDT believes that the current language is satisfactory, and few comments were received suggesting need for a modification.		
MidAmerican Energy Company	Yes and No	MidAmerican Energy Company (MEC) believes the definitions are improved. However, MEC suggests that the SDT clarify what stability analyses are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons.
MRO NERC Standards Review Subcommittee	No	The MRO believes the definitions are improved. However, the MRO suggests that the SDT clarify what stability analysis are required such as angular and voltage stability for which time frames such as the transient and steady state time frames and for what planning horizons such as the Near-Term and Long-Term planning horizons. Generating Unit Stability Study definition - The MRO suggests deleting the text, "on the Transmission Facilities connected to that generating unit(s) point(s) of interconnection or one bus away from that point.", because certain Generation Facility contingencies should be considered and key Transmission Facility contingencies can be more than one bus away from the interconnection point. System Stability Study definition - The MRO suggests this alternate wording: "Study that focuses on portions of the System, which may include many generating units with various Contingencies. This study is concerned with loss of synchronism, lack of damping of inter-area power oscillations, and voltages during the dynamic simulation." We suggest this wording because the definition of a study should not give the criteria, but rather the general elements of the study.
Response: The SDT believes that your comments requesting clarifications have been addressed through the changes made as shown. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.6.2** (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: **R5**. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning		

Organization	Question 1:	Question 1 Comments:
Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2. 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. The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5		
Arkansas Electric Coop. Corp.	Yes and No	There are situations where one bus away may not be far enough. While one bus may cover most situations the standard shouldn't limit the study to just one bus away. Suggested language change: Transmission Facilities connected to that generating unit(s) point(s) of interconnection, one bus away from the electrically closely-coupled units.
Response: The definition for Generating Unit Stability Study has been deleted so the offending phrase is no longer in this standard.		
NERC and Regional Coordination (PJM)	No	In the definition of Consequential Load Loss - Revise Transmission Planning Entities to Transmission Planners; or otherwise clearly identifying the entities that are meant to be addressed by the term "Transmission Planning Entities. "Revise "which" to "that" as indicated by the text below that is in quotes and Upper Case: Load that is no longer served because it is directly connected to an element(s) that is removed from service due to fault clearing action or mis-operation connected to a source as a result of the event being studied or "THAT" is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load "THAT" is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, [Transmission planning entities] TRANSMISSION PLANNERS are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements. Regarding the definition of Planning Event -The given words do not define the term. For example is an event meant to be an forced outage condition; or is meant to be any set of state conditions. If an event can be anything, then the term is not a definition. Planning Coordinator -Explicitly state that this definition will be deleted when the functional model definition for this entity is approved May consider deleting the term because it is not unique to this standard. The term is already defined in the Functional Model.R1.1 ? Data changes are routine in such studies and need to better quantify when technical justification is required.

Organization	Question 1:	Question 1 Comments:
Response: The definition of Consequential Load Loss has been changed in an attempt to clear up issues such as you addressed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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.		
IESO	No	(i) Generating Unit Stability Study: We do not agree with the phrase "…or one bus away from that point." This limits the scope of the testing to only the next bus. At times, contingencies that remove critical transmission facilities several buses away from a generating plant may affect generating unit stability performance. We suggest to reword this phrase to "..or in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance."(ii) Long-Term Transmission Planning Horizon: A nit-picking suggestion to change the first "longer" to "long".(iii) Planning Coordinator: We not see the need to repeat a definition that is already provided in the NERC Glossary of Terms and the Functional Model. There is a plan to implement a wholesale change from Planning Authority to Planning Coordinator. This is expected to occur in the first half of 2009.(iv) System Stability Study: Since voltage performance is included in this assessment, we suggest to add to the phrase "?which may include many generating units AND GROUPS OF TRANSMISSION FACILITIES..".(v) Year One: The second part of the definition is confusing. By "12-18 months from the completion of the previous annual Planning Assessment." does it mean 12-18 months from the "complete date" of the previous assessment, or from the "end of the previous assessment period"? For example, a previous assessment was completed on April 30, 2008 that covers a 12 month period from May 1, 2008 to April 30, 2009. Does year one for the subsequent assessment start from May 1, 2009 or May 1, 2010? In view of the confusion, having only the first sentence would suffice. In fact, there is only one reference made in the requirement (R2.1.1). Qualifying "year one" can easily be made in that requirement without having to have a defined term. Adding defined terms without a good cause adds to the maintenance task for the glossary of terms. Further, it begs the question on why "year two" and "year five" referenced in that same requirement are not defined.
Response: With regard to your comments (i) and (iv), the SDT agrees and has modified the definitions and Requirements accordingly. **R2**. Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~. **R2.6.1** (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.		

<table>
<tr><th>Organization</th><th>Question 1:</th><th>Question 1 Comments:</th></tr>
<tr><td colspan="3">
R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:
R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~
The wording of sub-requirements R5.6.1 and R5.6.2 was modified and relocated to become bullets under Requirement R2.5.2.
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.
The definitions of Generating Unit Stability Study and System Stability Study as well as the following sub-requirements were deleted: R2.5, R2.5.1, R2.5.2, and R5.5.
(ii) Thank you for your suggestion. The SDT sees no material difference in the suggested change and has decided to leave the definition unchanged.
(iii) As you note, NERC is transitioning from the use of the term Planning Authority to the term Planning Coordinator. Since the new terminology has not been officially adopted yet in the Functional Model, it must be defined in this standard revision.
(v) The definition is intended to be flexible to accommodate different practices and schedules. The key points are: 1) an assessment must be done each year and completed any time during the year, 2) the first year of the assessment period should be beyond the period examined to address operational planning issues, and 3) the time to complete the assessment could vary and take up to 18 months. In your example, if you have chosen Year One to be May 1, 2008 to April 30, 2009, then Year One for the subsequent assessment would begin May 1, 2009.
</td></tr>
<tr><td>Dominion - Electric Transmission Planning</td><td>Yes</td><td></td></tr>
<tr><td>TVA System Planning</td><td>Yes</td><td></td></tr>
<tr><td>City Water, Light & Power -</td><td>Yes</td><td></td></tr>
</table>

Organization	Question 1:	Question 1 Comments:
Springfield, Illinois		
Tenaska, Inc.	Yes	
US Army Corps of Engineers, Northwestern Division	Yes	
JEA	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: Thank you for your response.		

2. Do you concur with the modified Requirements R2.4, R2.5, R5.4, and R5.5? If not, please state why and/or suggest specific changes.

Summary Consideration:

In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address any potential conflict between this standard and the FAC standards.

Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient.

Requirement R2.4.3 has been modified to remove the need for stating the technical rationale for why or why not a particular sensitivity was selected. Requirement R2.4.4 was deleted because it was essentially a voluntary requirement. The specific wording for each of the sensitivities to be considered has been changed and should be clearer as to what is needed. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. This is covered in the revised Requirement R1.1.1.

Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting “smaller entities.”

The definitions for Generating Unit Stability Study and System Stability Study have been deleted and the following requirements have been added or changed due to industry comments:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

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

R2.1.4 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 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 due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

- ~~Variations in~~ Load model assumptions
- ~~Modification of e~~Expected transfers
- ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities.
- ~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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.

R3 For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.4 (now R3.5) Those Extreme Events in Table 1 ~~– Steady State Performance~~ 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 R3.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R5. For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~

R5.2 (now R4.3 and R4.3.1) Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention.

R5.4.4 (now R4.5) ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~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 R5.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted.

The following requirements were deleted due to industry comment:

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

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

R2.5.1 ~~New generator(s) are added or generation modifications are made such as changes in generation capability or replacing the exciter.~~

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

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

R5.5 ~~For the Generating Unit Stability studies:~~

R5.5.1 ~~Shall be performed for individual generating units 20 MW or greater directly connected through a step-up transformer to the BES and for generating units at the same location which total 75 MW or greater, directly connected through their step-up transformer(s) to the BES.~~

R5.5.2 ~~Shall be performed for changes in the real power output of a generating unit by more than 10% of the existing capability or more than 20 MW whichever is greater.~~

R5.5.3 ~~Shall be performed and evaluated for those Planning Events that would produce more severe System impacts and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results.~~

R5.5.4 ~~Shall meet Performance requirements for Planning Events in Table 2 – Stability Performance~~

Organization	Question 2:	Question 2 Comments:
Dominion - Electric Transmission Planning	No	Comments are subdivided according to different sections as listed below: R2.4.1: In principal, we agree that the dynamic behavior of loads, including consideration of the behavior of induction motor loads, should be represented. However, it is not easy to get the data on such loads. Most customers, including industrial ones, have no information/knowledge regarding their load characteristics. Also, the software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on large HVAC compressor motors). Additionally, if the entire case is populated with such detail dynamic load data, the case could not be solved. A lot of research would be required. A phase-in period of several years should be considered in order to accomplish the fundamental objective of dynamic load modeling. Please refer to Item 4 of Question 15 for further thoughts on modeling requirements. R2.4.3: It is acceptable to perform studies that include various sensitivity factors, but to document all rationales why they were chosen or not chosen for each study performed is burdensome. R2.5.1: Reduction in generation does not decrease stability margins. Therefore, the previous version's "increasing in generation" should be kept instead of changing it to "changes in generation." R5.4.3: This requirement allows automatic generation tripping to mitigate Stability violations (subject to meeting three listed conditions there in). Automatic generator trips should not be allowed for N-1 contingency studies (beginning with system normal and evaluating for the very first contingency) should the full output of the generating unit be classified as a capacity resource. Allowing a capacity resource generator to trip for N-1 contingency could result in reduced system reliability.

Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: The SDT agrees and has modified the language of Requirement R2.4.3 to not require the rationale for why a sensitivity was chosen or not.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 2:	Question 2 Comments:
R2.5.1: The SDT has removed the distinction between System Stability and generating unit Stability. Requirement R2.5.1 has been deleted. R5.4.3: This requirement has been deleted.		
NPCC	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement "R5.4.3.4 Automatic generator tripping shall not have an Adverse Reliability Impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point of 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Hydro-Québec TransEnergie (HQT)	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point f. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
New York	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying

Organization	Question 2:	Question 2 Comments:
Independent System Operator		modeling in paragraph 2.4.1 (dynamic behavior of loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." b. In paragraph R.2.4.3.4, what does "variability" mean? c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. ---- g. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement is now also part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

Organization	Question 2:	Question 2 Comments:
R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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. **f**: Generating unit Stability and System Stability have been combined.		
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
ISO New England Inc.	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately.

Organization	Question 2:	Question 2 Comments:
		Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
National Grid	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5 - The concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the

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		operating horizon unless otherwise defined in the planning horizon. j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include " other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1
Central Maine Power Company	No	a. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted. b. In paragraph R.2.4.3.4, what does "variability" mean? Is variability more of a concern than an outage? Suggest changing paragraph R.2.4.3.4 to simple say "Outages of Reactive Resources" c. Add a new requirement, "R5.4.3.4 Automatic generator tripping shall not have an significant adverse impact on overall system reliability." d. Remove Heading R5.5 and make generator unit stability for a new facility a section of overall stability requirements. e. Modify R5.5.1 to become R5.4.5, with the following, "Shall be performed for the addition of an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point. f. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary and R5.5.2 should be deleted. g. If the output of a generating station does not change by more than 20MW, then no new study is required and, it should be acceptable to rely on past stability assessments. This is not clear in R5.5.1. h. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment. i. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Organization	Question 2:	Question 2 Comments:
		j. The provisions of Section R.5.3 should be included in a MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. k. Strike R5.5.3 and R5.5.4, as they become redundant to R5.4.1

Response: a: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

c: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

d: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

e: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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.

f: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.6.2.

<table>
<tr><th>Organization</th><th>Question 2:</th><th>Question 2 Comments:</th></tr>
<tr><td colspan="3">
g: Requirement R5.5.1 has been deleted.
h and i: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from Requirement R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4.
R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.
R2.1.4 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 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 due to the unavailability of the long lead time equipment.
j: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL.
k: Generating unit Stability and System Stability have been combined.
</td></tr>
<tr><td>NSTAR Electric</td><td>No</td><td>
1. A MOD standard should be developed to address the assembly of dynamic load models, rather than specifying modeling in paragraph 2.4.1 (dynamic behavior of loads, including consideration of the behavior of induction motor Loads). Paragraph 2.4.1 should instead read, "System Peak Load for one of the five years." The remainder of the paragraph should be deleted.
2. Change paragraph R.2.4.3.4 to "Outages of Reactive Resources". It is not clear what "variability" means and why it would be more severe than outages.
3. Add a new requirement, "R5.4.3.4 Automatic generator tripping schemes shall not be overly complex or have an significant adverse impact on overall system reliability."
4. Requirements of R5.5 should be rolled into R5.4 and made applicable to all stability studies.
5. Modify R5.5.1 to the following "Shall be performed for an individual generating unit or generating units at the same interconnection point 20 MW or greater that are directly connected to the BES." There may be little difference between the stability performance of a single 20 MW unit and an aggregation of units totaling 20 MW at the same BES interconnection point.
6. Delete R5.5.2. If planning assessment studies all generators or stations above 20 MW, as suggested by R5.5.1, then this provision is unnecessary. If the system has not changed, it should be acceptable to rely on past stability assessments.
7. With respect to section R5, the concept of planned and long-term outages should be addressed uniformly for the general Planning Assessment. It should not be specific to the Stability Assessment.
</td></tr>
</table>

Organization	Question 2:	Question 2 Comments:
		8. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage. Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion. 9. The provisions of Section R.5.3 should be included in an MOD standard and applied to a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "…other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.

Response: 1: The SDT disagrees and believes it is appropriate to require this in the TPL standard. Requirement R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2: The specific wording for old Requirement R2.4.3.4 has been changed to "reactive resource capability". This could mean a degradation of the capability of a reactive resource. The TP is allowed to use its judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

3: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.

4: In response to industry comments, the SDT has removed the distinction in the standard between System Stability and generating unit Stability.

5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This requirement is now located at Requirement R2.5.2.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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.

Organization	Question 2:	Question 2 Comments:
6: There are no longer two requirements covering this. The new generator size which requires a study and the change of generator size which requires a study have been combined into Requirement R2.5.2. 7 and 8: The requirement to include "known planned and long term outages of Transmission or generation equipment" has been removed from R5. Planned outages are covered in Requirement R1.1.1 for both Stability and Steady State. Long term outages are covered in new Requirement R2.1.4. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R2.1.4** 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 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 due to the unavailability of the long lead time equipment. 9: This is the subject of PRC-024 currently under development. But the question of how you treated this in your planning studies belongs in TPL.		
City Water, Light & Power - Springfield, Illinois	No	Near term stability analysis should not need to be performed each year unless there is a significant change to the system or the previous study(ies) showed marginal performance.
Response: The near term Stability analysis does NOT have to be performed every year as long as you have a qualified past study which covers it.		
Progress Energy Carolinas	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are currently under development and may not be available for sometime. We believe that modeling the dynamic effects of loads is becoming increasingly necessary to obtain meaningful results. Therefore, it is appropriate that the revised standards address this. However, the present state of the industry is such that effective implementation of this requirement, as currently written, cannot be realistically achieved in the near term. The software tools currently in use do not accommodate the modeling of certain material effects (for example the load reduction due to thermal trips on HVAC compressor motors). Additionally, detailed load information necessary to allow the models which are available to be populated with meaningful data is not typically available or readily obtainable. Without resolving these issues, load model data submitted via the MMWG process will not improve simulation accuracy and could actually reduce the accuracy of results. Therefore, we would recommend R 2.4.1 rewritten to either a) allow a multi-year, phased approach to incorporating dynamic load modeling in simulation dynamic databases or b) provide an effective date for this particular requirement well into the future. This will accomplish the fundamental objective in a more accurate and meaningful manner. At least 48 months should be allowed before this requirement becomes effective. R 2.4.3 The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies. We propose removing the enumerated list of sensitivities starting with

<table>
<tr><th>Organization</th><th>Question 2:</th><th>Question 2 Comments:</th></tr>
<tr><td></td><td></td><td>R2.4.3.1 and rewording R2.4.3 as follows:

R2.4.3 For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios shall be performed. The rationale for the sensitivity(ies) selected shall be documented.

R 2.4.3.1 As stated above, this sub-requirement should be removed. However, if it is to remain, it should be clearly stated whether the Load model refers to system load or the dynamic load model at individual busses.</td></tr>
<tr><td colspan="3">Response: Requirement R2.4.1 has been modified to clarify that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard.

Requirement R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The SDT believes an enumerated list is more appropriate than the list that you suggest and an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

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

R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load</td></tr>
<tr><td>BCTC</td><td>No</td><td>BCTC's open access tariff requires generator owners to apply for interconnection studies and facility studies to interconnect to our system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. In fact, we may only be aware of the changes indentified in these requirements when generator owners make these applications. The generator owners are required to pay for these studies. Study requirements for generator interconnections are further defined by NERC Standards FAC-001 and FAC-002 (Coordination of Plans for New Facilities). By including these requirements in TPL, BCTC is concerned that generator owners may think that they are no longer required to pay for the studies. Furthermore, the NERC standards would have redundant requirements. If SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Any</td></tr>
</table>

Organization	Question 2:	Question 2 Comments:
		studies resulting from new generators or increases in existing generator output should be charged to the owner.
Response: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.		
Manitoba Hydro	Yes and No	R2.4: Agree with change except:R2.4.1.1: Needs to provide more detail on what is required to be compliant with respect to what is required to "appropriately represent the dynamic behavior of Loads including consideration of the behavior of induction motor Loads". Is the appropriate modeling left to the judgment of the TP/PC, supported by peer review by adjacent planners? Should the TP be required to document why the dynamic modeling is appropriate. The requirement implies a requirement to consider detailed dynamic load modeling at every bus in the model as opposed in areas of high concentration of such load. - needs clarification. R2.4.3: Generally agree, except:R2.4.3.1:Can the SDT clarify if the Variations in load model refer to variations in dynamic load modeling" R2.4.3.4, what is meant by variability of reactive resources? R2.4.4: The use of the words "shall be run" implies that additional scenario(s) are mandatory. Was this the intent of the SDT? R2.5: As stated in Q1 above, Manitoba Hydro continues to believe the Generating Unit Stability Analysis duplicates the FAC-002-0 requirements, creating potential for contradiction/non-compliance of both standards. The SDT should ensure there is no duplication of requirements of the FAC-002-0 standard. R2.5 should allow use of current or qualifying past studies. R2.5.1: Is it the SDTs intent that the TP could rely on the Planning Assessment R2.5 and/or R5.6 to assess the impact of a generator addition or modification. This function should be the subject of an interconnection study conducted in accordance with the FERC tariff (LGIP) or other similar TP interconnection process. R2.5.2: The TP planning process for addition of facilities should be used to verify the impact of changes to the network, including changes near existing generators . A planning assessment is not the appropriate process. Other Comments related to R2:R2: There appears to be no requirement for an assessment of system stability in the long-term planning horizon. Was this the intent of the SDT? R2.1: States the "steady state analysis shall be assessed annually and be supported at a minimum by the following annual current studies: Does the term ?annual current studies? preclude doing an assessment by using only qualified past studies? Please clarify!

Organization	Question 2:	Question 2 Comments:
		R2.1.1 & R2.1.2: NERC/ERAG will likely have to the models developed annually to ensure appropriate models are available. For example, in any given model series produced in past, there may not be a year five. Also, does System off-peak load refer to summer off peak? R2.1.3: While Manitoba Hydro supports the need for scenario assessments, this significantly increase the workload for studies and documentation. The requirement to document why a scenario was not selected will present a problem, since without doing the study, the planner may not have a good justification. The long term objective to improve reliability could be met by requesting only different sensitivity per year, and dropping the need to justify why others were not done. R2.6: Manitoba Hydro suggests that this requirement be converted to a definition of Past Studies. The definition should state that both R2.6.1 and 2.6.2 are necessary to qualify as a past study? R2.7:In the case were a CAP is required to meet the system performance requirements, will the assessment be deemed to be compliant on the assumption that the CAP will be put in place in a timely manner? R2.7.1.1: Can the SDT please clarify project initiation date? What is it? date permitting starts? Date construction starts? Etc R5.4: System Stability. The SDT should clarify if contingencies are to be applied to all elements in the case, or is it left to the judgment of the planner. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies" were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe. R5.4.1: Manitoba Hydro agrees that the rationale for Contingencies selected should be provided. However, it is an onerous task, and of little value to provide rationale for the contingencies not selected. R5.4.2: Manitoba Hydro's preference is that the performance requirements should be in the standard body. The approach in Table 2 is inconsistent. R5.4.2 refers to Table 2 for Planning Event performance requirements, however, for the Extreme Events, the Table 2 refers back to R5.4.4. R5.4.3: Manitoba Hydro agrees and commends the SDT for recognizing generator tripping as a viable option for meeting the performance requirements in certain systems. R5.4.3.2: Agree that regulatory and statutory requirements must be met; however, the references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by

Organization	Question 2:	Question 2 Comments:
		a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the reference to safety and equipment be removed. R5.4.3.3: can the SDT clarify how they want the planner to determine that "a sustainable operating condition is maintained". Demonstrating stability over a 20 second stability run may be sufficient, or is the SDT looking for longer time frame stability modeling. R5.4.4 The requirement to explain why extreme events were not chosen add extra documentation. The TP has to explain why certain events were chosen, consequently, events not chosen are judged to have less impact. What would the SDT deem an adequate explanation? R5.5: Generating Unit Stability - As stated above, Manitoba Hydro does not agree that assessment of Generating Unit Stability is necessary as it is covered by FAC-002-0. R5.5.1: This requirement implies the Generating Unit Study should consider every unit exceeding 20 MW. Consistent with R2.5, the SDT should clarify that only new generators need be studied. R5.5.3: Given the numerous possible contingencies that could be run if multiple contingencies are considered, it is impossible to explain why the remaining contingencies were not selected. Other Comments related to Requirement R5:R5: The sentence ?The studies shall be based on computer simulations using models using data provided in Requirements R9 to R14 ?..? should apply to both steady state (R3) and stability portions, yet it is only included in R5. R5.1: Essentially repeats the requirement in the first sentence of R5 - suggest deleting. R5.2: Suggest deleting the words ?including those? R5.3: Manitoba Hydro suggests that frequency ride through be added in addition to voltage ride through. The language "how the generators are treated in the simulation" is not crisp. Is the SDT looking for information on how the voltage ride through and frequency ride through are modeled in the study?

Response: R2.4.1 has been modified to clarify that an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. It is not necessary to have a dynamic Load model which is specific to each bus. The determination of the aggregate Load model is left to the judgment of the TP/PC.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

Organization	Question 2:	Question 2 Comments:

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load.

R2.4.3.4: The specific wording for Requirement R2.4.3.4 has been changed to variations in "reactive resource capability". The sub-requirement has also been changed to become a part of a bulleted list. This could mean a degradation of the capability of a reactive resource. The TP is allowed to use his judgment as to how the variations of the sensitivity parameters should be made.

~~Variability and outages of r~~Reactive resource~~s~~ capability.

R2.4.4: Requirement R2.4.4 has been deleted.

R2.5: The SDT agrees with the Industry's majority view that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability. This should address your concern with potential conflicts with the FAC standards.

Other Comments related to R2: Yes, no System Stability is required for the Long-term Planning Horizon.

R2.1: Yes, current studies are required for Requirement R2.1. The assessment for steady state cannot be based solely on past studies.

R2.1.1 & R2.1.2: Not necessarily. The intent was that off-peak refers to any Load level other than peak that the TP deems appropriate.

R2.1.3: R2.1.3 and R2.4.3 have been modified to remove the requirement for specifying the technical rationale for why or why not a particular sensitivity was selected.

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

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

R2.6: A formal definition would apply to all NERC standards. The SDT believes this explanation of what qualifies as a past study should only apply to this standard.

R2.7: Not necessarily. While the SDT can't answer as to formal compliance, the intent was that If the corrective action will not be in place at the time it is needed, the PC/TP will not be in compliance unless it can find an acceptable way (perhaps an Operating Procedure) to meet the performance requirement.

R2.7.1.1: This requirement is now Requirement R2.6.2. It is left up to the individual entity to define and document what is meant by the project initiation date. This requirement was intended to represent the same thing as Requirement R2.1 in the existing TPL-002-0.

R5.4 and R5.4.1 (now R3.4): The SDT believes the existing wording does allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Organization	Question 2:	Question 2 Comments:
R5.4.2: The SDT agrees that this cross-referencing is inconsistent. The reference back to Requirement R5.4.4 has been removed from the Table. R5.4.3: Thank you for your comment. R5.4.3.2 and R5.4.3.3: The SDT agrees and has removed these requirements. R5.4.4: The SDT believes that Transmission Planners know their Systems well enough to select Contingencies for which they suspect cascading or severe problems will result. Since there are an infinite number of possible scenarios to study, judgment is a necessity to limit scope to a reasonable level. The judgment of the TP is assumed to be a sufficient explanation as to why certain Contingencies were chosen. R5.5: The distinction between Generating Unit Stability and System Stability has been removed from the standard. R5.5.3: The requirement has been deleted. R5: Requirement R3 has been modified to be consistent with Requirement R5. **R3** For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. R5.1: There is a difference between the two. The first sentence of Requirement R5 says to run Contingencies. Requirement R5.1 says to meet performance requirements. R5.2: The SDT agrees and has removed those words from new Requirements R4.3 and 4.3.1: **R5.2 (new R4.3 and R4.3.1)** Contingency analyses shall: ~~s~~Simulate the removal of all elements ~~including those~~ that the Protection System ~~protection~~ and other automatic controls are expected to disconnect for each Contingency without operator intervention. R5.3: The SDT is looking for how generators were treated in the study when there were voltage excursions. Did you trip them or not? What criteria do you use to decide if they should be tripped?		
Los Angeles Department of Water and Power	No	R2.4.3 requires sensitivity on various operating scenarios. These are best required under TOP, not TPL. It is totally useless and a waste of time to look at operating scenarios under planning horizon by planners, whether it be short term or long term. Operating scenarios are absolutely necessary under operating horizons but they need not be repeated and required in TPL when TOP already addressed these. R2.5 See my comment on question 1. This may be a suitable place to require proper modeling of the generator units to replace the existing languages.

Organization	Question 2:	Question 2 Comments:
		R5.4 is fine. R5.5 See my comment on question 1. The language here actually infers the size of a unit that should be modeled individually and not be lumped. But it should be more precise to prohibit any lumping as well as the explicit modeling of all dynamic data of any generator unit meeting the size requirement.
Response: R2.4.3: The SDT does not view the required sensitivity studies as operating studies. These are planning studies intended to investigate conditions that are different from the base case to bracket the range of possible outcomes if conditions vary from expected. R2.5: The SDT agrees with the majority of the Industry, including your comments, that there is no significant distinction between generator and System Stability and has modified the third draft to remove that distinction. R5.4: Thanks for your comment. R5.5: This requirement has been deleted.		
Transmission Agency of Northern California	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub requirements of R5.4.3. We believe these conditions should be met for a
Response: R2.4: thanks for your comment. The SDT agrees and has deleted Requirement R5.4.3.		
Pacific Gas and Electric Co.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in sub requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT

Organization	Question 2:	Question 2 Comments:
		needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Public Service Company of New Mexico	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or

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		modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Puget Sound Energy, Inc.	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in sub-requirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Idaho Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner

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		may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SMUD	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. ‘Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.

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Sierra Pacific Power Company / Nevada Power Company	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to 'cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Black Hills Corporation	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or

Organization	Question 2:	Question 2 Comments:
		REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
SRP	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by

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		the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tucson Electric Power Company	Yes and No	In general, R2.4 is acceptable but some of the sub-requirements are to prescriptive. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. Off-peak analysis (R2.4.2) in the Planning Horizon is of limited value for smaller entities. This analysis is best left to the Operating Horizon. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Modesto Irrigation District	Yes and No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to

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		specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Tri-State G&T	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirements in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and

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		assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
ColumbiaGrid	Yes and No	R2.4 is acceptable. Please consider deleting R5.4.3. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable. We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariff requires Generator Owner to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase

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		in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Southern California Edison	Yes and No	R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network. ? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Alberta Electric System Operator	No	R2.4 is acceptable. - Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or

Organization	Question 2:	Question 2 Comments:
		are generic. Otherwise, R5.4 is acceptable.- The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 and FAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Generator Owners are to apply for interconnection to the transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yet R5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator. The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. – Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
US Bureau of Reclamation	No	Comments: R2.4 is acceptable. Please consider deleting the conditions identified in R5.4.3.1, R5.4.3.2, and R5.4.3.3. We question the need to specifically call out these requirement in subrequirements of R5.4.3. We believe these conditions should be met for any and all requirements of the standard. It should not be necessary to list acceptable practices, especially if the conditions placed on the practice are general conditions that are addressed elsewhere or are generic. Otherwise, R5.4 is acceptable.? We generally agree that Transmission Owners with extensive Transmission Planning Function and Planning Coordinators need to perform and be held accountable for the Requirements in R2.4 and R5.4; however, the SDT needs to define an organization size level below which these requirements for the associated Transmission Planner may be slightly relaxed. There are numerous Transmission Planners; (e.g., those associated with PUDs, Municipals or REA, etc. where historically dynamic stability has not been a problem), for which performing these type of studies and assessments would be onerous and would not yield reliability benefits for the network.? The proposed requirements in R2.5 and R5.5 are already covered in FAC-001 andFAC-002 and should not be included again in the proposed TPL-001-1. Otherwise, the NERC standards would have redundant requirements. In addition, Transmission Owner's open access tariffs requires Generator Owners to apply for interconnection to its transmission system or to make modifications to their generators as described in R2.5.1, R5.5.1, and R5.5.2. It is therefore the Generator Owner's responsibility to cause these studies to be done at the time of interconnection or modification, yetR5 seems to place that responsibility only on the Transmission Planner and the Planning Coordinator.

Organization	Question 2:	Question 2 Comments:
		The Transmission Planner or the Planning Coordinator would not know of the changes until notified by the Generator Owner. If the SDT believes that FAC-001 is deficient, it should propose revisions to this standard, not simply add to TPL. Requirement R5.5.2 needs to be clarified to state changes or additions to the generating unit that result in an increase in power output. Otherwise, it could be interpreted to apply to existing units with a change in dispatch.
Response: R5.4.3: This requirement and its sub-requirements have been deleted. R2.4 and R5.4: Stability studies will continue to be required for smaller utilities. Small entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities". R2.5 and R5.5: The SDT changed the language to reflect that updated Stability studies only need to be performed as specified in Requirements R2.5.2. 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. R5.5.2 This has been clarified with the words "change of individual generating unit capability". This is now covered in Requirement R2.5.2		
Gainesville Regional Utilities	Yes and No	For smaller systems, please see Comment 1. As far as R.2.4.1, if the various loads are basic and not a large industrial type load (very large motors with across the line starting, electric arc furnaces, etc.) then the dynamic behavior of the load should not require special consideration. Using proper power factors for the load should be enough for the transmission system evaluation. Under 2.4.3, as mentioned in Comment 1, evaluating the stressing of the smaller systems through a large amount of sensitivities does not add any reliability to the BES. It only adds much addition work to a limited resource entity. If the neighboring large systems agree that the smaller system can not impact them, this should support that the BES is not affected by any sensitivity that could exist on the smaller system. For R5.5, a threshold should be set to consider only the larger size units within the region. For a smaller system, the stability of a 50-100 MW unit probably would not perturb the interconnected regional BES's.
Response: R2.4.1: Residential air conditioners and other small motors can have a significant impact on dynamic simulations of the System. Using proper power factors for the Load is definitely not enough for dynamic simulations of Systems with large amounts of residential air conditioning. R2.4.3: In Order 693, FERC directed NERC to modify the TPL standard to require that critical System conditions be determined by conducting sensitivity studies. The SDT believes this should apply to any entity regardless of size that is registered as a Transmission Planner.		

Organization	Question 2:	Question 2 Comments:
R5.5: The SDT believes the appropriate size to study is any generator of 20 MW or more.		
JEA	Yes and No	R2.4.1 Do we mean "Appropriate" for overall regional system response/behavior or for individual customer behavior. JEA would agree to an "appropriate" overall regional system response/behavior model with unique individual or sub-regional customer behavior models if determined significant. R2.4.3.1 JEA would agree to a load characteristic sensitivity studies if conducted within the scope of a RRO study. Suggest modifying wording to "Variations in Regional Load model assumptions" R2.4.3.3 Not sure what we mean by Unavailability of long-lead time facilities. Need to add a definition. If the standard is suggesting to treat the unavailability of autotransformers like the unavailability of generators i.e. N-2 assessments with no firm consequential load shedding, then JEA does not agree that the failure rate of autotransformers is on the same level as generators and do not agree this requires a minimum performance standard to maintain grid reliability. In addition, a utility is most likely to be successful in finding a reasonable useful spare autotransformer somewhere in the world to replace the failed unit. R2.5 JEA agrees. R5.4.2 See comments for steady state requirements for Table 1 P5.R5.4.3 JEA does not understand what is meant by Stability violations. Do we mean to say "unstable system conditions"? R5.5 JEA agrees
Response: R2.4.1: The intent is "appropriate for overall System behavior", but not just on a "Regional" basis. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3.1: The SDT believes that this requirement should apply to an individual TP, not on a Regional level. R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new requirement, Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns. ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. **R2.1.4** 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		

Organization	Question 2:	Question 2 Comments:
(such as a transformer), an analysis of the impact 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 due to the unavailability of the long lead time equipment. R2.5: Thank you for your comment. R5.4.2: "Stability violations" means that the System did not meet performance requirements for Stability studies. R5.5: Thank you for your comment.		
PacifiCorp	Yes and No	av? We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Arizona Public Service Co.	Yes and No	We generally agree that utilities or large TPs and PCs need to perform and be held accountable for these Requirements; however, the SDT needs to define a organization size level, below which these requirements for the associated TP may be slightly relaxed. There are numerous TPs; (e.g., those associated with PUDs, Municipals or REA, etc.), for which performing these type of studies and assessments are onerous and do not yield reliability benefits for the network.
Response: Stability studies will continue to be required for smaller entities. Smaller entities have the option of not registering as a TP to avoid compliance concerns. Furthermore, it would be difficult to establish criteria for exempting "smaller entities.		
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	? R 2.4.1 System peak Load for one of the five years. 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. R 2.4.2 System Off-Peak Load for one of the five years. Is there an inconsistency here in that the requirement for peak system load levels specifies details on what is needed for the load models, but the off-peak does not specify this? We don't believe this is the intent but it creates an appearance that the dynamic behavior of loads is not required for off-peak.? Regarding R2.4 and R2.5 (& R5.4.1): It should be made clear that redoing studies is only necessary when it is not certain as to whether or not a system change will have a negative impact on system stability. An explanation should be sufficient if a study is unnecessary based on technical knowledge.. As to dynamic load models, we agree with a much longer implementation period than the rest of the standard.

<table>
<tr><th>Organization</th><th>Question 2:</th><th>Question 2 Comments:</th></tr>
<tr><td></td><td></td><td>We have concerns that an auditor may not agree with our judgment as to what studies should be run or not run (R2.4, R2.5 and particularly in the case of R5.4.1). Additional guidelines, perhaps in the measurements section, would be appreciated.?</td></tr>
<tr><td colspan="3"> Response: R2.4.1 and R2.4.2: The dynamic behavior of induction motor loads has caused problems (e.g., slow voltage recovery) at higher System Load levels. Thus the requirement in the TPL standard is to make sure you properly represent the behavior of induction motor Loads at high Load levels, i.e., peak. It is not as much of a problem at lower Load levels and therefore there is no requirement for off-peak Load levels. Of course, even at off-peak a proper representation of Loads is needed. But for lower system Load levels, standard models are usually sufficient. R2.4 and R2.5: For R2.4 (Stability Studies) current or qualified past studies must be used to show that the five year period has been assessed. This means the TP must be able to demonstrate with engineering judgment that past studies are still valid. Dynamic load models: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. R2.4.1 System peak Load for one of the five years. 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. <u>An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.</u> R2.4 and R2.5: The SDT does not believe that additional guidelines are needed. The standard leaves room for appropriate engineering judgment by the TP. </td></tr>
<tr><td>Progress Energy Florida, Inc.</td><td>No</td><td> R2.4.4 as worded does not make sense, and could potentially create illogical situations where the Transmission Planner or Planning Coordinator would "offer up" additional sensitivities specific to their systems, for which they might not presently be analyzing and immediately have to self-report non-compliance. As a substitute to the language in R2.4.4, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.4.3.6 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator. Regarding R5.4 and R5.5, PEF disagrees to the extent that a differentiation has been made between System Stability and Generating Unit Stability (see Question 1 comments). Given that System Stability and Generating Unit Stability are held to precisely the same standards in Table 2, PEF feels that significant modification is required to R5.4 and R5.5, specifically that the two sections need to be consolidated into a single section. Given the complex nature of Stability Analysis, and the fact that Generators are inextricably intertwined with all other components of the BES, the distinction that the SDT is attempting to make with this issue makes no sense from a power systems engineering perspective. </td></tr>
<tr><td colspan="3">Response: R2.4.4: The SDT agrees and has deleted this requirement.</td></tr>
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Organization	Question 2:	Question 2 Comments:
R5.4 and R5.5: In response to industry comments, the SDT decided that generating unit Stability and System Stability need not and should not be treated as distinct issues. The Stability related requirements have been modified to create a single generic set of requirements that no longer distinguishes between generating unit and System Stability.		
Lafayette Utilities System	Yes and No	Requirement 2.4.1 directs the furnishing of information that would reveal the location of new large inductive loads. Large inductive loads typically are induction motors used in industrial applications. Therefore, a Distribution Provider's forecasts about the expected level of its inductive load could effectively reveal non-public information about the anticipated location of new industrial loads. If a Distribution Provider were required to disclose such information to its Transmission Planner, the confidentiality of information having considerable commercial and competitive significance could be compromised. This would be of particular concern if the Transmission Planner and the Distribution Provider also happen to be competitors for new retail loads.
Lakeland Electric	No	Modeling the dynamic behavior of Loads is difficult at best and merits a discussion or white paper. Recommend requirement 2.4.1 specify the size of induction motor that should be considered and comment on modeling of small induction motor loads such as air conditioning.
Orlando Utilities Commission	No	OUC supports the comments from FPL and Lakeland Electric on this issue.
Response: Requirement R2.4.1 has been modified to clarify that a detailed dynamic load model is not required at each bus. An aggregate system load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.		
Ameren	Yes and No	In R2.4, it is suggested that the word "System" be re-inserted ahead of the word "Stability". It is believed that the sub-requirements of R2.4 are for System studies as opposed to Plant or Generator stability studies. In R2.4.1, agree that the system peak load should be studied for at least one of the five years in the near-term planning horizon. What is the meaning of the term "appropriate", and who decides what dynamic representation of load is "appropriate", and for what conditions? Guidelines for the development of load models used in power flow and dynamic models to represent residential air conditioner induction motor load response including the effects of underground distribution cable and distribution capacitor banks are not available. Why can't the standard load representation be used to meet R2.4.1, and the more detailed load representation,

Organization	Question 2:	Question 2 Comments:
		including dynamic system induction motor load response, be used to meet R2.4.3? In R2.4.2, agree that off-peak load levels should be covered for one of the five years. In R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Further, these items in R2.4.3.1-5 appear to be options and not sub-requirements, and therefore are too prescriptive and inappropriate for inclusion here. The proposed sensitivities appear to over-focus on the particular issues listed and may result in the detriment of overall system reliability. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case is burdensome. We are unsure if R2.4.4 is a requirement or an option. If R2.4.3 were not so prescriptive, the additional sensitivity could be covered under the engineering judgment comment provided above. The prescriptive listing of sensitivities under 2.4.3.1 through 2.4.3.5 should be eliminated. Proposed alternative wording for R2.4.3 which addresses above concerns is as follows:R2.4.3. "For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected." R2.5 should be reworded as follows. "The Generating Unit Stability portion of the Planning Assessment shall be assessed for the year and conditions when the following changes that could affect stability margins occur:" Agree with most of R5.5. In R5.5.4, a risk/benefit vs. cost analysis should be included in the evaluation of implementing a change to mitigate the likelihood of cascading outages for the extreme events. Agree with R5.6.

Response: R2.4: Adding the word "System" is no longer necessary because the SDT has eliminated the distinction between System Stability and Generating Unit Stability.

R2.4.1: The TP and PC decide what is appropriate for their System.

R2.4.1: The sensitivity of studying effects of induction motor Loads may not be chosen by the TP. The SDT thinks that studies incorporating the effects of induction motor Loads must be done for peak Load levels.

Organization	Question 2:	Question 2 Comments:
R2.4.2: Thank you for your comment. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements have been converted into bullet lists. R2.4.4: Requirement R2.4.4 has been deleted. R2.4.3: The SDT believes an enumerated list is more appropriate than the list that you suggest and as stated above, an enumerated list must have a sub-requirement format. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. R2.5: In response to industry comments, Generating Unit Stability has been combined with System Stability. Requirement R2.5 on Generating Unit Stability has therefore been deleted. R5.5.4: This requirement has been deleted. R5.6: Thank you for your comment. The separate requirement for Generating Unit Stability Studies has been deleted.		
Florida Power and Light	No	R2.4.4 is inappropriate for a compliance assessment. Essentially R2.4.4 requires the Transmission Planner or Planning Coordinator to deem appropriate and justify inclusion or exclusion of any sensitivity other than the required sensitivities listed in R2.4.3. The only way that a an entity could be found non-compliant is if the entity deems a sensitivity as appropriate, and then inexplicably did not perform the sensitivity, which makes no sense. The requirement seems to put a burden of justifying by "technical rationale" a sensitivity that is deemed appropriate already. R2.4.4 could be eliminated and its intent absorbed in R2.4.3 by changing its wording slightly: "R2.4.3 For each of the studies in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect conditions including, but not limited to, one or more of the following conditions, shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied."
Response: The SDT agrees and has deleted Requirement R2.4.4. Other sensitivities deemed appropriate by the TP or PC can always be run.		
Exelon Transmission Planning	No	R2.4 should be specific as to applicability to generator stability, system stability or both. R2.4.1 requires the use of load models for motors. Detailed load data may not be available and studies would therefore produce questionable results. It is our understanding that the industry has recognized the importance of using better load models and there are multiple ongoing initiatives to improve our ability to do this modeling but these initiatives are not complete. However, the industry's ability to provide accurate models is not sufficient to ensure compliance at this time. The sensitivities for near-term studies in R2.4.3 aren't clearly defined, especially R2.4.3.3, 'Unavailability of Long Lead Time Facilities'. Doesn't the study that determined the original need for these facilities document the consequence of

Organization	Question 2:	Question 2 Comments:
		unavailability? The peer review component of the Planning Assessment has CEII concerns, especially with regard to extreme contingencies and whether or not they involve cascading.
Response: R2.4: In response to industry comments, Generating Unit Stability has been combined with System Stability. Therefore, Requirement R2.4 applies to Stability analysis. R2.4.1: The intent of R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3 and R2.4.3.3: The sensitivities in Requirement R2.4.3 have been reworded for better clarity. Old Requirement R2.4.3.3 for unavailability of long lead time facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date and how you would plan to get around that problem. Also, a new Requirement R2.1.4 has been added to cover unavailability of major Transmission equipment. ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. **R2.1.4** 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 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 due to the unavailability of the long lead time equipment. Peer review comment: The SDT does not believe this to be an issue because the existing standards TPL-001 through TPL-004 already require in Requirement R1.3 a review of assessments by Regional Reliability Organizations.		
CenterPoint Energy and CPS Energy	No	We believe the requirements are overly broad and overly prescriptive. We further believe the extent of the "problem" these requirements would address does not justify such overly broad and overly prescriptive requirements. To clarify, we wholeheartedly agree that transmission planners should consider and selectively study potential stability concerns. However, we believe that transmission planners are already considering and selectively studying potential stability concerns. We are not aware of any significant bulk electric reliability problem actually occurring in recent memory due to the failure of transmission planners to perform the assessments and studies this standard proposes to require. Some might argue that instability occurred in the northeast blackout, and we would agree. However, requiring transmission planners to perform all the assessments and all the studies proposed herein would not have prevented instability from occurring in that event. A targeted approach focusing on the specific vulnerabilities of that area of the

Organization	Question 2:	Question 2 Comments:
		network would be far more effective than the scattergun approach proposed here. Furthermore, even if all the stability analyses proposed in this standard were performed and audited, the studies likely would not have revealed the actual underlying reliability concern. In the end, the root cause of the failure was thermal overloading, not stability. Instability eventually occurred when the root cause (thermal overloading) led to a situation where circuits sequentially tripped over the course of an hour or so. Events that occur over the course of an hour are generally outside the scope of stability analyses, so these proposed requirements are off the mark for that event. We recommend deletion of R2.4.3, R2.4.4, R2.5, R5.2, R5.3, R5.4 (or 5.5), and R5.5 (or R5.6). Removing this excess baggage would allow transmission planners to use their judgment to selectively analyze stability concerns germane to their system. We realize such an approach requires a recognition that transmission planners are already doing the appropriate analyses, and we encourage the SDT to be receptive to this premise. To further clarify this last point, some would argue that assuming entities are already doing the right thing belies the underlying premise behind enforceable reliability standards. We believe that acceptance of the need for enforceable reliability standards does not pre-suppose that some or all entities are always doing the wrong thing all the time in all aspects of their business. Nor does acceptance of mandatory reliability standards require acceptance that all aspects of the business are equally likely to produce reliability concerns. We believe most or all entities are already doing some things well such that, in some aspects of the business, there is no evidence that a "problem" actually exists. If the SDT accepts this premise, it would focus its attention on actual problem areas, not imaginary ones. We submit that performing appropriate stability studies is not a "problem" that requires an the overly prescriptive requirements proposed here. Rather than solving an actual problem, these requirements are more likely to detract resources from actual concerns by causing planning resources to be expended documenting and defending to auditors that imaginary concerns do not exist.
Response: The SDT disagrees and believes the Stability requirements are necessary to ensure that appropriate studies are being made.		
MidAmerican Energy Company	No	a. MEC disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term

Organization	Question 2:	Question 2 Comments:
		Transmission Planning Horizon shall be assessed annually?.". ? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5.
Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall system behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. b: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: A new substation in a line could change the requirements for relaying on the new shorter line so that the generating unit remains stable. Zone 2 clearing from the generator end of the line may not be fast enough on a shorter line. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct.		
SERC Dynamics Review Subcommittee	No	R 2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for some time. The implementation plan should take this into account and allow at least 36 months for implementation; otherwise this requirement will not be achievable in the near term. R 2.4.3 One should only explain why sensitivity was performed. In general we believe that breaking these requirements into specific sub-requirements focusing on specific sensitivities is too prescriptive and inappropriate; it will lead to over-focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses. We have a specific proposal for R2.4.3 which addresses the above concerns as follows: R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) that stress the

Organization	Question 2:	Question 2 Comments:
		System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time Facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R2.4.1: Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted. The sub-requirements are now part of a bullet list. For Requirement R2.4.3.1: The variations in Load model assumptions are to be applied to the aggregate System Load model which represents the overall dynamic behavior of the Load		
MRO NERC Standards Review Subcommittee	No	a. The MRO disagrees with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. If this requirement is retained then R2.4.1 should be modified to specify a minimum threshold size where dynamic induction motor load or dynamic load behavior becomes significant such as near mining areas. The SDT should consider a 25 MW size threshold for induction motors and a 100 MW size threshold for industrial complexes where the dynamic loads are inadequately represented by normal power flow dynamic assumptions. b. R2.4 as stated refers to Near-Term Transmission Planning Horizon Stability analysis but there is no requirement in the standard referring to Long-Term Transmission Planning Horizon Stability analysis. The SDT should reword R2.4 so that it is clear that no Long-Term Stability analysis is required by stating that "Stability analysis for the Near-Term Transmission Planning Horizon shall be assessed annually?.". ? The MRO does not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. ? In R2.4.3.1, what is meant by “variations” (e.g. how much variation is enough)? ?

Organization	Question 2:	Question 2 Comments:
		In R2.4.3.2, what is meant by “modification” (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? ? In R2.4.3.3, what is meant by “long lead time” (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? The MRO suggests that “long lead time” be stated 18 months or more.? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale?? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. The MRO notes that R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings should be included in the Glossary Definition by adding the words "within the applicable time period of the rating" and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: a: The intent of Requirement R2.4.1 is to have dynamic Load models which are appropriate for overall System behavior, not necessarily on an individual substation basis. The SDT believes that type of model is available. Requirement R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b: R2.4: There is no requirement in the standard for Long-Term Transmission Planning Horizon Stability analysis. The only requirement is for Near-Term Transmission Planning Horizon Stability analysis. The SDT believes this is clear in the standard.

R2.4.3: The requirement to explain why or why not sensitivities were selected has been deleted.

R2.4.3.1: The variations in load model assumptions are to be applied to the aggregate system Load model which represents the overall dynamic behavior of the Load. The amount of variation is left to the judgment of the TP and PC.

~~Variations in~~ Load model assumptions

R2.4.3.2: The wording has been changed to variations in expected transfers. The amount of variation is left to the judgment of the TP and PC.

~~Modification of e~~Expected transfers

R2.4.3.3: The requirement for unavailability of long lead time Facilities has been broken into two pieces for better clarity. Old Requirement R2.4.3.3 has been

Organization	Question 2:	Question 2 Comments:
clarified with the words "Timing of the installation of new or modified Facilities". For example, this would include consideration of a new line not being in service by the scheduled date. Also a new Requirement R2.1.5 has been added to cover unavailability of major Transmission equipment. These modifications should help alleviate your concerns. ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. **R2.1.4** 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 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 due to the unavailability of the long lead time equipment. R2.4.4: The SDT agrees and has deleted Requirement R2.4.4. R2.5.2: This requirement has been deleted. Requirement R5 has been re-numbered due to deletions and the sub-requirement numbering is now correct. R5.4.3.1: The SDT believes the existing definitions of Facility Rating and Equipment Rating sufficiently cover the time limited aspect of the ratings.		
Austin Energy	No	The routine sensitivity cases requirement contained in R2.4.3 is overly burdensome and unnecessary and should be deleted. Sensitivity analysis should be limited to what may be deemed appropriate by the Transmission Planner or Planning Coordinator. Similarly, R2.5 and R5.5 requirements for Generating Unit Stability should be deleted. Removing these burdensome requirement will allow transmission planners and/or the Planning Coordinator (ISO) to determine the appropriate Generator Unit Stability analysis needed as part of R5.4 System Stability.
Response: R2.4.3: The SDT believes that running sensitivity cases will give the TP a better understanding of its System and better understanding yields a more reliable System. The requirement for sensitivity studies is not overly prescriptive. There is much room for the engineering judgment of the TP. The sub-requirements have been converted into a bullet list. R2.5 and R5.5: The separate System and Generator Unit Stability Requirements have been removed from the Standard and replaced with Requirement R2.4, which addresses all Stability studies. Appropriate levels of generation additions are listed as bullets under Requirement R2.5.2; 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.		
Midwest ISO	No	The language in R2.4 retains the appropriate clarification that while annual assessments are required, these assessments do not necessarily have to be based upon annually performed simulations. This same distinction should be retained for steady-state assessments required under requirement R2.1, not withstanding the fact that steady-state simulations are easier to perform. The principle is the same for both. Requirement R2.4.1 is to open ended in

Organization	Question 2:	Question 2 Comments:
		specifying the years to be studied. Rather, it should parallel requirement R2.1.1 in requiring that at a minimum either year one or two should be evaluated, and additional years at the option of the responsible entity. If the system could go unstable in the next 1-2 years, it is important to know this. Regarding R2.4.3 & R2.4.4, the standards should not require analysis for which corrective action is optional regardless of the conclusion of the analysis. Requirement R2.7 establishes that corrective action to any sensitivities is optional. Therefore, the performance of sensitivities should be at the discretion of the applicable entity. If the SDT believes it is important to recommend that sensitivities be performed then those Requirements addressing sensitivities should state that the performance of the sensitivity is recommended but optional. If you keep sensitivities in the standard then the requirement in R2.4.4 to document why an entity performed sensitivities in addition to the Requirements should be dropped. As long as the entity selected a sensitivity and documented the results of the sensitivity there should be no reason to explain why he tested it. Requirement R2.5.2 is unclear with respect to when generator unit stability needs to be retested following modifications to the transmission system. Nearly all additions to the transmission system will tend to improve generator stability. We suggest this language be modified to say: "Material transmission system changes are made at or near the point of interconnection of existing generation that would tend to degrade stability margins of that generation, such as the removal of a transmission line, or associated with the addition of new generation, or other system changes as determined by the Planning Coordinator or Transmission Planner". R5.4.3.1 & R5.4.3.3 are redundant with the stated requirement to mitigate stability. Under the sub requirement of R5.4.3.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this sub requirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements". Subrequirements R5.4.3.X are superfluous; we suggest removing these subrequirements. However, if this requirement is retained it should be amended to include the following sentence: "Automatic generation tripping is allowed to mitigate Stability violations if the performance criteria in Table 2 is met".

Response: R2.4 The Requirement is allowing the TP and PC the option to determine which time frame to study so as not to be as prescriptive as Requirement R 2.1.1.

R2.4.3 & R2.4.4: The language of Requirement R2.4.3 has been changed to clearly state the objective of sensitivity analyses and their applicability.

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

Organization	Question 2:	Question 2 Comments:
R2.5.2: This language has been removed from the Standard. R5.4.3.1 & R5.4.3.3: The specific sub-Requirements have been removed from the Standard; they are already implicitly covered in the Standard.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	R2.4.1 "System peak load" needs a definition. Forecast descriptions by the utility should describe probability levels and other specifics.
Response: The SDT has changed this language in Requirement R2.4.3 by allowing the use of sensitivities already considered in the base case. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
AEP	No	We are concerned about unintended consequences with regard to System Stability studies, specifically, the possibility of generating unnecessary work. We would like the SDT to consider language changes that recognize the following realities. (1) While System Stability studies may be justified as a more detailed look at contingency scenarios whose observed severity in steady-state analysis suggests the need for more in-depth study, they cannot be expected to achieve the same breadth of scope as steady-state analyses. In decoupling System Stability studies from steady-state analysis, the draft standard may unnecessarily tend to force stability study scopes to approach those of steady-state analyses. (2) The characteristic limiting factors of systems are generally known (whether thermally limited, voltage drop limited, or transient or small-signal stability limited) and in many systems the limiting factors are thermal or steady-state voltage, but not stability. The draft standard may end up forcing System Stability studies to be done solely for compliance. It is not that independent System Stability studies are never justified (they are, for example, where inter-area small-signal instability is a known factor), but in many systems, they are not necessary. We observe that as sub-requirements of R2 and R5, R2.5 and R5.5 are the responsibility of the Transmission Planner and Planning Coordinator. Is it the SDT's intention that these entities be responsible for conducting the Generating Unit Stability analysis, irrespective of the ownership of the generating units? Should the Generator Owner be responsible for conducting the Generating Unit Stability analysis?
Response: (1) The SDT agrees that Stability studies are more in-depth; the study requirements for Stability are less than that of Steady State. (2) Not in all areas, there are numerous Systems that are limited by Stability, not just thermal limits. R2 and R5, R2.5 and R5.5: The distinction between Generating Unit Stability and System Stability has been removed.		

Organization	Question 2:	Question 2 Comments:
Southern Company Transmission	No	R 2.4 needs to have the word System inserted in front of the word Stability. R 2.4.3 One should only have to explain why a sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. R 2.4.3.1 It should be clearly stated whether the load model refers to system load or the dynamic load model at individual busses A specific proposal for R2.4.3 which addresses the above concerns is provided as follows:R2.4.3. For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as variations in dynamic Load model assumptions, modification of expected transfers, unavailability of long lead time facilities, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios. Document why each sensitivity was selected.
Response: R 2.4: The distinction between Unit and System Stability has been deleted. R 2.4.3 The SDT has changed the language of R2.4.3 to reflect this; to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities was not chosen has been removed. R 2.4.3.1: The language has been changed to allow the Transmission Planner to use their judgment in application of sensitivities. ~~Variations in~~ Load model assumptions R2.4.3 The SDT wanted to keep the sensitivities clear from the rest of the language for base case study requirements. The language of this section has been changed and the use of documentation has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	We do agree with the wording change in 2.4 which uses 'assessed annually'. 2.4.1 and 2.4.2 are ok. 2.4.3 is not agreeable, as it implies or could imply a number of studies are required. Stability studies are not required as often as steady state studies. A new in-line load serving substation can certainly impact the steady state results of an area but would not have the same impact from a steady state perspective. In other words, we feel that running stability studies for a number of small variables does not provide any added benefit and thus stability studies should not be treated the same as steady state studies from a requirement standpoint. More emphasis should continue to be

Organization	Question 2:	Question 2 Comments:
		placed on the steady state analysis. 2.4.3 should be edited to say "Sensitivity cases as deemed appropriate by the TP or PC, that stress the System (or BES) may be run reflecting one or more of the following conditions. Other sensitivities not included below may also be run. Appropriate documentation should be included describing the rationale for the selection of the cases and conditions "delete 2.4.4 as it is taken care of in 2.4.3 2.5 can be deleted as it adds nothing to the stability requirements2.5.1 should be modified to be included under 2.4 as a required study with the caveats from 5.6 brought over defining parameters, or delete 2.5.1 altogether as 5.6 covers the addition of generation.2.5.2 is still fairly ambiguous even with the changes and should be deleted. However if kept it should be modified to remove the last part of the sentence beginning with "or the addition of a new substation?". The addition of a simple in-line substation does not have a material impact on the stability of a near-by plant.2.6.1 and 2.6.2 should be combined to remove the mention of generating plant stability. deleting 5.4 is ok Not sure of the need to add 5.5.2. Isn't that the intent of the whole Standard? 5.5.3 seems to be acceptable.

Response: R2.4: Thanks for your comment.

R2.4.3: The SDT has changed this language to clarify the requirement; the use of documentation has been removed from the language.

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

R2.4.4: This part of the Standard language has been removed.

R2.5: This part of the Standard language has been removed and bullets under (new) Requirements R2.5.2 have been added to the language to clarify this position.

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.

R5.5.2: This requirement was deleted.

Organization	Question 2:	Question 2 Comments:
NERC and Regional	No	PJM concurs with the general direction; however the sensitivity analysis section as written requires explanation of why

Organization	Question 2:	Question 2 Comments:
Coordination		certain sensitivities were not selected. However the sensitivity requirement must be defined. Prove the rationing. R2.4 should state for stability we should use light load rather than system peak which is for steady state analysis. R2.4 should be modified as followsR2.4 should be modified as followsR2.4 The Near-Term Transmission Planning Horizon portion of the Stability analysis requires: Suggest making all sub requirements bullets under R2.4 The words in R2.4 seem to state that the "analysis must be assessed annually" which seems to leave open the option of assessing an old study, whereas R2.2. and R2.3 state a study is required each year, and a study is conducted each year. The words need R2 must be clearer and more consistent. System stability requirements seem to be poorly defined. It appears that there is going to be an expectation that inter-area oscillation and small signal analysis be performed frequently over a variety of conditions. I'm not sure how geared up industry is for this. R2.4.1 is too ambiguous. This sub requirement requires a model that "appropriately represents the dynamic behavior of loads". However, the requirement does not reference how that judgment is made nor who would make the judgment. The sub bullets are vague and again provide no basis for performance or for arbitration. R2.4.4 should be deleted as it will deter TPs and PCs from conducting additional studies. R2.4.4.1-5; Should clearly define words like variation, modification, unavailability of long lead time facility, variability of reactive resources. R2.5 is ambiguous regarding the definition of "affects stability margins". What is the technical performance margin for "affect"? If not defined in the standard then who makes the decision? The TP? the auditor? NERC staff? Do you mean critical clearing time and how much of change for example percentage or cycle.

Response: The SDT has changed this language to reflect that this is to examine one sensitivity or more and the documentation requirement has been removed.

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

R2.4: The SDT has determined that both Peak and Off-Peak should be studied; another Load case can be evaluated as a sensitivity.

R2.4 does state that an assessment shall be performed each year and the applicability of past studies is listed in Requirement R2.6.

R2.2. and R2.3: The language clearly states that a study is required for one of the years in the assessment period.

The SDT believes that each TP and PC should have discretion to determine the appropriate Stability studies applicable to their System.

Organization	Question 2:	Question 2 Comments:
R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.4 The SDT has deleted this section. R2.4.4.1-4 (now R2.4.3): The SDT has changed the language in these sections and made them a bulleted list. ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.5 This section of the Standard language has been removed.		
IESO	No	A. R2.4(i) We suggest to remove words such as "consideration of" and "deemed appropriate" since these are not measurable and not enforceable. Further, we continue to disagree with mandating sensitivity testing with descriptive subrequirements. Sensitivity testing (ii) Specific to R2.4.3, we continue to express our disagreement to include sensitivity testing in the requirements. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TPs and PCs discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself. B. R2.5 (i) Similar to our comments under Q1 (i), the requirements should not restrict to changes at or near the Interconnection point. Transmission changes several buses removed from the generator's Interconnection point may also affect the stability performance of the generators. Suggest to reword it to "? in the nearby vicinity that can have an adverse reliability impact on the generating units' stability performance".(ii) There seems to be a hole or incomplete scenario in R2.5.2 in the sentence: "removal of a Transmission Line or the addition of a new substation in one of the Transmission Lines connected to the plant." We agree that removal of a transmission line in the vicinity needs to be assessed; we also believe that addition of not just a substation but also any transmission facilities in the vicinity should be assessed. We therefore suggest to reword this to: "removal of a Transmission Line or the addition of new

Organization	Question 2:	Question 2 Comments:
		transmission facilities in the generating plant's nearby vicinity that can have an adverse reliability impact on the generating units' stability performance. C. R3.4 (i) We do not agree with the requirement that: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of implementing a change designed to reduce or mitigate the likelihood of such consequences shall be conducted." Future transmission systems are planned and designed accordingly to Planning Events. It should not be a surprise that applying Extreme Events to the planned transmission system for which it is not designed to withstand such events would show instability and/or cascading outages. The follow on actions should be to evaluate possible actions to contain and minimize the impact of cascading outages, rather than to come up with options or alternative designs to reduce or mitigate the likelihood of such occurrences (since doing so will imply that we design and plan for Extreme Events). We therefore suggest to reword it to: "If the Extreme Events analysis concludes there are cascading outages, an evaluation of possible actions to contain and minimize the impacts of cascading outages.

Response: The SDT examined the use of these terms and still believes that these are the best terms to use here.

The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

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

R2.5: This section of the Standard language has been removed.

R3.4: The SDT has modified this requirement (now Requirement R3.5 and also Requirement R5.5.4 – now Requirement R4.5) to include mitigating the "adverse impacts of the event(s)."

R3.5 Those Extreme Events in Table 1 ~~– Steady State Performance~~ 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 R3.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences and adverse impacts of the event(s) shall be conducted.

R4.5 ~~At a minimum, t~~Those Extreme Events in Table ~~2~~1 ~~– Stability Performance~~ that ~~would~~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 R4.2 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results. If the ~~Extreme Events~~ analysis concludes there are cascading outages caused by the occurrence of Extreme Events, an evaluation of ~~implementing a change~~ possible actions designed to reduce ~~or mitigate~~ the likelihood or mitigate ~~of such~~the consequences of the event(s) shall be conducted

Organization	Question 2:	Question 2 Comments:
North Carolina Electric Membership Corp	No	We assume that 2.4 is supposed to be for "System" Stability. Please confirm.R2.4.1 - Is this for On-Peak? Please confirm. Also the subrequirement that requires a model that "appropriately represents the dynamic behavior of loads" is too ambiguous. The requirement does not reference how that judgment is made nor who would makes the judgment. The sub bullets are vague and provide no basis for performance. It should be clarified. How does the TP/PC model 3rd party loads from LSEs or DPs within its area that it interconnects? Is there an additional requirement to LSE/DPs needed in R9-R14 to collect such characteristics of load data? There is concern with load modeling requirements (use of word “appropriately” in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? The subrequirements of R2.4.3 are much too vague and are subject to various interpretations. These should be more specific as to what should be assessed, e.g. 5% variation in load model. Why aren't the last 2 subrequirements already accounted for within the assessment? R2.5 is ambiguous. What is meant by "affects stability margins"? What is the technical performance margin for "affect"? As defined by whom? The TP/PC? the auditor? Is this a % change or what? R5.4 – OK R5.5 - We are OK with changes made, but we do share a concern with others that the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria) per R5.5.1 may be too much, and we recommend also a 75 MW generator cutoff for required simulations.

Response: R2.4: The terms ‘unit’ and ‘System’ have been removed from the language and Stability has replaced them.

R2.4.1: Yes, this is for peak conditions. Requirement R2.4.2 is listed for Off-Peak Load.

R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3: This list of sensitivities is not overly prescriptive and allows the use of engineering judgment of the Planner. Language has been changed to provide clarity.

Organization	Question 2:	Question 2 Comments:
~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. The specific wording for Requirement R2.4.3.4 has been changed to "Reactive resource capability". This could mean a degradation of the capability of a reactive resource. This would not normally be covered in the assessment unless sensitivity studies require it. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios would not necessarily be studied in the assessment unless there were firm plans to change generation. The purpose of sensitivity studies is to answer "what if" questions which would not otherwise be covered in the assessment. R2.5: This language has been removed from the Standard. R5.5 The requirement for study has been changed to 25MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. 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.		
E.ON U.S. Transmission Planning	Yes and No	R2.4 The Near-Term Transmission Planning Horizon portion? implies that there are other portions of the [System] Stability analysis. This needs to be reworded to make it clear that there are no other portions. Add the word "System" to make it clear. R5 The data to be included in all models for the Planning Assessment is included in R1. The discussion here is redundant. This should be deleted. R5.4.3.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: R2.4: The wording used is appropriate; there are no Stability Requirements beyond Near-Term R5: That language has been removed and replaced by language in Requirement R1. **R5** (now R4.) For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in~~		

Organization	Question 2:	Question 2 Comments:
~~Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted~~ R5.4.3.1: This section of the language has been removed but these principles are applicable throughout the Standard.		
ERCOT System Planning	No	ERCOT believes R2.4.3, R2.4.4, R2.5, R5.2, and R5.3 should be deleted and R5.4 and R5.5 should be combined as follows: R2.4.3 should be deleted due to the unacceptable increase of stability runs required to meet the requirement. Considering sensitivities for outages of reactive resources and various dispatches and retirements for at least two different load levels is beyond the capability of most organizations, for both technical and manpower reasons. R2.4.4 is unbounded and not measurable, and should not be included as a requirement. R2.5 and all requirements for Generating Unit Stability analysis should be deleted since there is little or no difference between this and System Stability. R5.2 should be deleted because contingency definition standards should be defined in a modeling standard.R5.3 Voltage ride through capability should be included in the model provided by the generator and should not be necessary as a requirement in the TPL standard. R5.4 and R5.5 could be combined, as there is little or no difference between Generating Unit Stability analysis and System Stability analysis. In this case, R5.5.1 and R5.5.2 would be moved to R5.4 and R5.5.3 would be removed (repeats R.5.4.1).Also, it appears that R5.4.1 is in conflict with R5.4.2 because R5.4.1 says ?identified and evaluated for System Performance? but not have to meet requirements but R5.4.2 says ?meet requirements ? Table 2?. Also, R5.4.2 is repetitious with text of R5.
Response: The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.4 and R2.5 were deleted from the language of this draft Standard. R5.2 and R5.3 The SDT did not agree to delete this language; language is needed to be in the Standard describing Contingencies and the use of low voltage ride through in studies. (Note that in the revised standard, Requirements R5.2 and R5.3 have become Requirements R4.3 through R4.3.2.) R5.4 & 5.5: The SDT has removed the distinction between System Stability and generator unit Stability.		

Organization	Question 2:	Question 2 Comments:
American Transmission Company	No	We disagree with the proposed R2.4.1 text. This inclusion of this requirement may be premature at this time for several reasons. There is presently no industry consensus on how the dynamic behavior of loads should be properly represented and analyzed. In addition, it would be a large and difficult effort to identify, collect, and maintain the pertinent information. It is presently difficult to obtain and maintain the percentage of residential, commercial, and industrial load at each transmission interconnection point, much less try to get the proper percentage of the various types of induction motor loads. We do not accept the R2.4.3.1 text and want some explanation of the what, when, and how to provide the technical rationale for why each condition was or was not used. In R2.4.3.1, what is meant by ?variations? (e.g. how much variation is enough)? In R2.4.3.2, what is meant by ?modification? (e.g. how much modification is enough) and "expected transfers" (e.g. firm or non-firm transfers)? In R2.4.3.3, what is meant by ?long lead time? (e.g. 1 month, 1 season, 1 year, 2 years, etc.)? In R2.4.4, we believe this requirement should not be added. Why was it included? It seems superfluous, because any entity can study other sensitivities if they want. Why should TP or PC have to study what the other entity wants to study? Who would be the judge in case of disagreement over the technical rationale? In R2.5.2, Why was the addition of a new substation included? We would not expect a new substation to negatively impact the system or generating unit stability. We note the R5.5 and R5.6 should really have been updated to refer to 5.4 and R5.5. In R5.4.3.1, we suggest that the time-limited aspect of Facility Ratings be included in the Glossary Definition and then it would not need to be clarified in various locations (R3.3.2.2, R3.5.1, R5.4.3.1, Table 1-Note 1, & Table 2-Note 1) throughout the standard.

Response: R2.4.1: The SDT has changed the language of Requirement R2.4.1. The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

R2.4.3.1 The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.2, The SDT has changed the language of R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. R2.4.4 has been removed from the language of this Standard draft. R2.5.2: This language has also been removed from this draft Standard. R5.5 and R5.6: This new version contains renumbering which should address your concerns. R5.4.3.1: This section of the language has been removed but these principles are applicable all throughout the Standard.		
Duke Energy	No	R2.4.1 Load models that appropriately represent the dynamic behavior of induction motors are under development and may not be available for sometime. The implementation plan should take this into account and allow at least 36 months for implementation. This requirement is not immediately achievable. R2.4.3 - Although we agree with the perceived intent of R2.4.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. R2.4.3.1 should clearly state whether the load model refers to overall system load or parameters of the dynamic load model at individual busses. Recommend renumbering R2.4.4 to R2.4.3.6, and reword R2.4.3.6 as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.R2.4 should say "System Stability", not just "Stability".
Response: R2.4.1 has been modified to clarify that a detailed dynamic Load model is not required at each bus. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable. Because of this clarification, the SDT believes that a 24 month implementation period for this requirement is sufficient. This will be covered in the Implementation Plan which will be posted along with the third draft of the standard. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3 The SDT has changed the language of R2.4.3 to reflect this, to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why~~		

Organization	Question 2:	Question 2 Comments:
~~each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R2.4.3.1 The SDT has changed this language to clarify that aggregate load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of loads at high system load levels. R2.4.4 to R2.4.3.6.The SDT has removed the distinction in the Standard between System Stability and generator unit Stability.		
Florida Reliability Coordinating Council, inc	No	R2.4.4 and R2.4.3 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant.R2.4.4 can be eliminated by changing the wording in R2.4.3 to include sensitivities? deemed appropriate by the TP or PC as follows:? For each of the studies described in Requirement R2.4.1 and Requirement R2.4.2, sensitivity case(s) deemed appropriate by the Transmission Planner or Planning Coordinator that stress the System to reflect, but not limited to, one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied.?
Response: The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivities and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes and No	R2.4. No The word "System" was deleted during the re-write and only "Stability" is used. However, the sub-sections appear to be more appropriate to a "System Stability" assessment than for a "Generating Unit Stability" assessment. "Generating Unit Stability" assessments are the subject of Section R2.5 and "System Stability" assessments appear to be the intent of Section R2.4. Why does Requirement 2.4. specify the near-term transmission planning horizon "portion"? We recommend removal of the words "portion of the". R2.4.1. No Change "Peak System Load" to "System On-Peak Load". This is the term defined in the "NERC Glossary" and is consistent with the usage of "Off-Peak Load". This change would be required through out the TPL Standard as well as in other standards. There is concern with load modeling requirements (use of word "appropriately" in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model?

Organization	Question 2:	Question 2 Comments:
		R2.4.3 NoIn general we believe that breaking these requirements into specific sub-requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities. Engineering judgment needs to be permitted. R2.5 Concur R5.4 Concur R5.5 No There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.
Response: R2.4: The SDT has removed the distinction between System Stability and generator unit Stability. R2.4.1 – The SDT does not believe there is any ambiguity in the term "peak System Load" and will continue to use that term. R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. R2.4.3 The SDT has changed the language of Requirement R2.4.3 to reflect examining one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: R5.5: The SDT agrees that there is little distinction between a single unit of a specific MW and an aggregation of the same number of MW. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2. 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.		
Oncor Electric Delivery	No	For Requirement R2.4 would prefer to see more clarification on the System Off-Peak stability studies required and their purpose. Define/quantify type of stability issues to be addressed with this type of study. For sub requirement R2.4.3 the level of detail in the load modeling is very subjective and greatly impacts the analysis

<table>
<tr><th>Organization</th><th>Question 2:</th><th>Question 2 Comments:</th></tr>
<tr><td></td><td></td><td>and results.</td></tr>
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Response: R2.4: Transient Stability is generally worse at lower System Load levels when base load units are still generating near maximum output. All of the Contingencies in the table are to be considered for Off-Peak Load levels

R2.4.3 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed.

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment

</td></tr>
<tr><td>FirstEnergy Corp.</td><td>No</td><td>

R2.4.1 ? 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 use of the words "appropriately represents" and "consideration" is too vague and not strong enough for requirement language. Also, the requirement needs to better describe what is needed related to the modeling of induction motor load. What % of the load needs to be represented as motor load for various load classes ? commercial, industrial, residential? An industry white paper is needed to provide direction related to this undertaking. The SDT, when considering their Implementation Plan, will need to allow sufficient time to complete the dynamic load modeling which largely does not exist today.

R2.4.3 ? Typo, need to remove strikethrough text on the word sensitivity.

R2.4.4 ? Suggest making this a sub-requirement of R2.4.3 and only require documentation as to why each sensitivity case was selected. Documenting why something was not selected does not seem constructive and places an unneeded burden on documentation. It should be expected that over time, a range of sensitivities would be covered as a library of studies is built.

</td></tr>
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Response: R2.4.1: The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable

R2.4.3 The SDT did not find the typo indicated.

R2.4.4 The language of R2.4.4 was deleted from the Standard language.

</td></tr>
</table>

Organization	Question 2:	Question 2 Comments:
Entergy Services, Inc.	No	General Comments: The enhanced requirements in this standard will result in an exponential increase in the amount of studies required to become compliant. Some of the changes such as the list of specific sensitivity studies will make it difficult to audit. Standards need to be measurable. As currently written, these requirements are difficult to measure. Furthermore, as indicated in the later questions, there could be significant costs to comply with these revised requirements Specific Comments: In 2.4.1, it would be better to address the "consideration of the behavior of induction motor Loads" in the sensitivity studies bullet, 2.4.3.1.,if this bullet is to be included at all. Furthermore, induction motor modeling is primarily required in areas with high load concentration that could be subject to angular and voltage stability issues. Considerable effort is required to collect information on motors. Therefore, studies to evaluate induction motor effects should be included in the sensitivity analysis section. In 2.4.3, what was the rationale for including only a portion of the sub-bullets included in 2.1.3? Also, in 2.1.3.7, does "Modification of planned Transmission outages" imply changes in dates? It seems unlikely that the cancellation of an outage would have negative impacts. More clarification is needed on what "modification" means in this requirement. R 2.4.3Each transmission provider has its own transmission planning needs and requirements. While it is true there are common elements and considerations that have to be incorporated in every transmission provider's planning process, it is difficult, if not impossible, to prescribe a list of sensitivities that is, or should be, applicable to everyone. Entergy has specific concerns regarding the following sensitivities. R.2.4.3.2 Modification of expected transfers: The use of "expected" transfer levels suggests that one can expect certain transfer patterns beyond what is modeled in base cases as firm. These sensitivities could result in an endless string of "what-if" scenarios where transmission users would attempt to influence these studies to advantage their respective market positions. Any system improvements based on such "expected" use of the system shall not result in discriminatory treatment of transmission users. R.2.4.3.5. Generation additions, retirements, or other dispatch scenarios. Generation additions are addressed by FERC-mandated study criteria. These requests are handled through the generation interconnection and system impact study processes. Generation retirements and other dispatch scenarios can have both positive and negative impacts on reliability. However, assumptions used to pick which resources are changed, and in what way, will likely be difficult to justify. R5.5 There is a concern with R5.5.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.
Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. For peak System Load levels, a Load model shall be used which appropriately represents the dynamic		

Organization	Question 2:	Question 2 Comments:
		behavior of Loads, including consideration of the behavior of induction motor Loads. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable R2.4.3The SDT has changed the language of Requirement R2.4.3 to examine one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability. R2.4.3.5: These are changes to consider as possible sensitivities to give the TP a better understanding of its System. There is no justification of your assumptions required by the Standard. R5.5 The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This is now located at Requirement R2.5.2. 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
BPA Transmission Reliability Program	No	R2.4.1 references the use of a load model which appropriately represents the dynamic behavior of loads. However, such load models have not been developed yet. We recommend removing that requirement for load models until these models have been developed and approved. R2.5 and R5.5 refer to Generating Unit Stability studies. As stated above under Item 1, Generating Unit Stability is adequately addressed by the System Stability studies and does not need to be evaluated separately. Footnote 5.a.i in the notes following the Performance Requirements Tables, already specifies the requirements to meet. Therefore, we recommend removing the section on Generating Unit Stability Studies from standard TPL-001-1. The focus of this standard should be on "System Stability" which encompasses all generating units .Some of the requirements listed under R5.4 apply more generally than just within this section and are already covered elsewhere in the standards. R5.4.3.1 is already covered in Note 1 of Table 1. R5.4.3.2 is not relevant to Reliability Standards and would already be addressed by the relevant regulations, so it does not belong in this Standard. R5.4.3.3 is already covered in Note 1 of

Organization	Question 2:	Question 2 Comments:
		Table 2. Because these requirements are already covered by other sections of the Standard, they can be removed from R5.4.
Response: R2.4.1 The SDT has changed this language to clarify that aggregate Load can be used here as well. This Requirement is to make you properly represent the dynamic behavior of Loads at high System Load levels. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable R2.5 and R5.5: In response to industry comments, the SDT has to remove the distinction in the standard between System Stability and generating unit Stability. R5.4.3.1: The SDT has decided to remove Requirement R5.4.3 because the sub-requirements are already implicitly covered by the standard. Your suggested sub-requirement is also already implicitly covered by the standard.		
PPL EnergyPlus	Yes and No	R2.4.3 and 2.4.4 together with R2.7 are a very good effort to direct TSPs to not let scenarios drive their plans. Rather, the base case should drive the plan. If anything, the language in the standard could be strengthened.
Response: R2.4.4 has been removed from the language. R2.4.3: The SDT has changed the language of Requirement R2.4.3 to one or more sensitivity and the documentation of the technical rationale for why each of the sensitivities not chosen has been removed. **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: ~~Variations in~~ Load model assumptions ~~Modification of e~~Expected transfers ~~Unavailability of long lead time Facilities~~ Timing of the installation of new or modified Facilities. ~~Variability and outages of r~~Reactive resource~~s~~ capability.		
TVA System Planning	Yes	
Tenaska, Inc.	Yes	

Organization	Question 2:	Question 2 Comments:
US Army Corp of Engineers, Northwestern Division	Yes	
Arkansas Electric Coop. Corp.	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

3. The SDT has modified the definitions of Consequential and Non-Consequential Load Loss in response to industry comments. Do you concur with the modified definitions of Consequential and Non-Consequential Load Loss? If not, please state why and/or suggest specific changes.

Summary Consideration:

In response to numerous concerns the following changes were made to the draft standard:

- The definitions of Consequential Load Loss and Non-Consequential Load Loss were modified to be more direct.
- New definitions were added for Load Reduction and Supplemental Load Loss to address issues that were previously included in the Consequential Load Loss definition.
- Changes were made in the notes for Table 1 (item b) to address application of the revised definitions.
- Note ‘b’ in Table 1 has been revised to associate comments on Load loss to Steady State rather than Stability.
- Footnotes 5 & 10 were added to the Table to differentiate between Firm Transfer Service and Load Loss.
- The SDT didn’t feel non-interruptible Load needed to be defined because Interruptible Load is a defined term.
- The requirement (old Requirement R3.3.2.1 – new Requirement R2.9) to specify the amount and duration of Load that may be lost was clarified to be the maximum for any Contingency and the requirement for duration was eliminated.

There is lingering concern in the industry with the following issues:

- The inability to shed firm Load for a first Contingency event
    - o The SDT considered this issue, but did not change the standard because it was specifically prohibited in FERC Order 693, Section 1773.
- The different treatment for Facilities greater than 300 kV versus Facilities less than 300 kV
    - o The SDT considered this issue, but did not change its perspective since the last posting. The following is the response provided in response to the first posting and the SDT has not been convinced that it should change:

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

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

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

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

There was no change with regards to the definition of Year One. The drafting team felt that if the studies referenced in the comments are duplicative, then the language in the Standard would allow them to use one study for both applications.

The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

With regards to comments on the definitions creating a disincentive to build network Facilities, the Standards do not specify how an entity will comply.

The following changes have been made to the definitions due to industry comment:

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

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions 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.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

The following requirement was added due to industry comments:

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

The following notes in the Table have been changed due to industry comment: ‘b’, ‘e’, and ‘i’.

Organization	Question 3:	Question 3 Comments:
Dominion - Electric Transmission Planning	No	Non-Consequential Load Loss: In the example provided with the definition of Non-Consequential Load Loss, it indicates that non-interruptible load loss that occurs through manual or automatic operations such as under voltage load shedding (UVLS), under-frequency load shedding (UFLS) or Special Protection Systems (SPS) would be considered Non-Consequential Load Loss. We recommend that the following statement be added to the standard in the definition -- "Interruptible loads such as the pump of a Pumped Storage Plant interrupted by an SPS should not be considered as a Non-Consequential load".
Response: The definition of the Non-Consequential Load Loss is qualified as ‘Non-Interruptible Load”. In your example, the Pumped Hydro load is defined as ‘interruptible’. There is nothing in the standard that associates Interruptible Load with Non-Consequential Load and nothing that prohibits the interruption of Interruptible Load. However, the SDT did change the definition to provide additional clarity. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
NPCC	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.
Hydro-Québec TransEnergie (HQT)	Yes and No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. It should be indicated that this also applies to " stability performance requirements" (refer to the end of last sentence of the definition).

Organization	Question 3:	Question 3 Comments:
Ameren	Yes and No	The revised definition of Consequential Load Loss needs to be simplified, as follows, "Consequential Load Loss: Load that is no longer served because it has been isolated from its network supply by a planned protection system operation to mitigate fault conditions." Additional clarifications as to when Consequential Load loss is allowed should not be included in the definition, but should instead be included in the Tables 1 and 2.Agree with the revised definition of Non-Consequential Load Loss.
Midwest ISO	No	Under the definition of consequential load, it is not clear who the term "Transmission planning entities" is referring to. Perhaps it should say "entities to which the standard is applicable". The last sentence could be amended to say: "Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS?..
Brazos Electric Power Cooperative, Inc.	No	Non-consequential is fine. For 'Consequential Load Loss' the entire last part of the definition that begins with "Although Load which is lost?" can be deleted or at least deleted to the part that begins with "Transmission planning entities are not allowed?". We think the last part of the sentence is intuitive.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
American Transmission Company	No	For Consequential Load Loss definition, we suggest that the last sentence be deleted because it is application text, rather than definition text. We accept the Non-Consequential Load Loss definition as written.
Florida Reliability Coordinating Council, inc	No	Propose changing the word ?a? to ?any? in the definition of Consequential Load Loss. Consequential Load Loss: Load that is no longer connected to ?ANY? source as a result ? The second sentence in the definition could be interpreted to disallow voltage dependent load models to meet Steady State Performance requirements. Since many planning events result in steady state voltage significantly lower than nominal, system load would be reduced. This definition would be clarified by differentiating load that is lost (no longer connected to a source) and load that is reduced as a result of reduced system voltage. Although Load which is lost (no longer connected to a source) as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load Loss to meet steady state performance requirements.
New York Independent System Operator	No	In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear.

Organization	Question 3:	Question 3 Comments:
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which has resulted in the elimination of the reference. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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.		
TVA System Planning	Yes	TVA agrees with the modified definitions. However, the definition for "Consequential Load Loss" can still be confusing. Suggest definition of "Load that is deenergized by relay action as a result of the event being studied ?." Additional wording in "Consequential load loss" about transient conditions can be confusing as well - we suggest including this additional information later in the document. For Non-consequential load loss, suggest use of "Firm" instead of "Non - Interruptible" Load Loss.
Response: The definition of 'Consequential Load Loss' has been revised to make it more direct and has eliminated the reference to 'transient'. There are potential associations with the term 'Firm' that the SDT is trying to avoid in this definition and therefore has decided to stay with the reference to Non-interruptible. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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.		
Progress Energy Carolinas	Yes	The definition of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for stability analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Note 'b" in the table has been revised to associate requirements to serve Supplemental Load Loss in Steady State rather than Stability. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response~~		

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. **Note "b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
BCTC	No	Our understanding of these definitions and the performance requirements in Tables 1 and 2 is that they may eliminate the existing provision in Footnote (b) that allows loss of firm load for contingencies in local networks. Disconnection of loads on local networks in response to contingencies normally requires RAS/SPS, and the definition of NCLL states that this is NCLL. We are not clear whether our concern is with the definitions of CLL/NCLL, the Tables, or the definition of BES. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is CLL, we do not see where FERC has ruled out the use of RAS/SPS for CLL - see BCTC comments on the First Draft at page 28 of the Consideration of Comments. BCTC concurs with SaskPower and Manitoba Hydro that that CLL needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. In addition, BCTC cannot meet the proposed P1 (A) > 300 kV Steady State Performance of no Non-Consequential Load Loss for part of our 500 kV system. One radial segment of the BCTC 500 kV transmission system, a single circuit 450 km 500 kV transmission system, serves load and interconnects generation. For outages of the 500 kV transmission line, a RAS is used to shed load to match the generation in this island. We have no plans for transmission reinforcements (280 miles of 500 kV transmission line) to remove this RAS. Therefore, we will require some further clarification of the proposed P1 (A) >300 kV requirement of no Non-Consequential Load Loss for this requirement to be suitable for all of our system.
Response: FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow		

Organization	Question 3:	Question 3 Comments:
loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. The SDT's interpretation of the Order is that FERC is indicating that other alternatives must be pursued to eliminate this operating scheme. However, the SDT has provided an exception (Requirement R2.6.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
Manitoba Hydro	No	The definition of Consequential Load Loss implies the load lost as a result of "response to the transient condition of the event" need not be load directly connected to the element impacted by the event, but load in the local area. This definition could result in an interpretation that would justify unlimited load loss resulting from say voltage depression in an area impacted by a transient system swing. This opens a loop hole for allowing load loss for many single contingencies as a result of a transient swing causing a voltage dip and motor contactor drop-out as an example. There is a fine line between providing adequate voltage support or operating guides to avoid such load loss. Should a maximum level of load loss be specified? Comments on Other Definitions: Extreme Events: The definition should clarify whether or not Transmission system performance requirements must be met. – Events should be changed to Event - same for Planning Events Planning Coordinator: The Planning Coordinator definition should be left to the functional model. Having the term defined here may cause future confusion. For example, the FMWG has discussed the possible elimination of the PC, based on the realization that it is the Transmission Planner who integrates resources into the transmission plans.
Response: The standard is not designed to address regional performance standards, which should govern relative to acceptable voltage depressions or the magnitude of acceptable loss of Load during Planned Events or in response to Extreme Events. This is the responsibility of the Planning Coordinator and the Transmission Owner, which has been included as notes 'e' and 'i' in Table 1. **Header note 'e"** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. **Header note 'i'**: ~~Dynamic voltages~~Transient voltage response shall be within acceptable limits established by the Planning Coordinator (or Transmission Planner if more restrictive).		

Organization	Question 3:	Question 3 Comments:
The reference has been reviewed and revised as appropriate. When the reference is to all events, such as in the title to Table 1, then 'Events' is correct. When the reference is to a single event, such as in the column header to Table 1, then 'Event' is correct. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.		
Los Angeles Department of Water and Power	No	In general, support the comment from WECC on this question, however, where there are different performance allowed solely based on an arbitrary voltage class separation, it is discriminatory and without any scientific or historical basis.
Response: Many responders have asked the question why the distinction for bus sections above 300 kV. The SDT has prepared the following response. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. When EHV Systems are compromised, the large volumes of power they serve can place a severe amount of stress on parallel EHV or lower voltage paths. For example, if a large EHV transformer experiences a catastrophic failure, not only are other systems Facilities required to carry more Load but the System is also exposed to other N-1 conditions for long periods of time while awaiting a replacement or repair of the failed equipment. Large generation sources are typically connected at EHV levels and maintenance of the EHV Transmission lines within the vicinity of large generation plants must often be coordinated during scheduled unit outages, resulting again in multiple Facility outages over extended periods of time. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half, or double bus-double breaker protection schemes as compared to the simpler, lower cost, single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the

Organization	Question 3:	Question 3 Comments:
California		interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversely impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Pacific Gas and Electric Co.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service

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		reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Public Service Company of New Mexico	Yes and No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49,

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		response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Puget Sound Energy, Inc.	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection used to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer will be degraded without commensurate improvement in overall system reliability. In addition, existing design of many such local networks may use RAS/SPS to disconnect loads on local networks in response to low probability contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to

Organization	Question 3:	Question 3 Comments:
		include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Idaho Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to

Organization	Question 3:	Question 3 Comments:
		eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
SMUD	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable.

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		The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Sierra Pacific Power Company / Nevada Power Company	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet

Organization	Question 3:	Question 3 Comments:
		steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Black Hills Corporation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Arizona Public	Yes and No	We generally agree with the definition but have concerns about a potential unintended consequence. This definition will

Organization	Question 3:	Question 3 Comments:
Service Co.		severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
SRP	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load

Organization	Question 3:	Question 3 Comments:
		Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tucson Electric Power Company	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

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Modesto Irrigation District		Comments: We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashioner avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require AS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss disallowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Tri-State G&T	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for

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		loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
ColumbiaGrid	No	We generally do not disagree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in

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		overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Southern California Edison	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the

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		faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6. While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote b of the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
US Bureau of Reclamation	No	We generally agree with the definitions by themselves but have concerns about potential unintended consequences. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 5 of 12the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. As a result, service reliability to customer would be adversity impacted without comments urate improvement in overall system reliability. In addition, existing design of many such local networks would normally require RAS/SPS to disconnect loads on local networks in response to contingencies. However, the definition of Non-Consequential Load Loss states that using RAS/SPS is Non-Consequential Load Loss. In the Consideration of Comments on the First Draft of TPL-001-1, page 49, response to First Energy, the SDT states "FERC has determined that any Load loss that is not directly connected to the faulted element is actually Non-Consequential Load loss." We found a similar response to WECC on page 449, item 6.While we do not disagree with the statements made by the SDT, that FERC wants clarification of what is Consequential Load Loss, we do not see where FERC has ruled out the use of RAS/SPS for Consequential Load Loss. Consequential

Organization	Question 3:	Question 3 Comments:
		Load Loss needs to include the concept of local networks. Another way to address this would be to exempt some local networks in the definition of the Bulk Electric System. The performance of existing systems has been designed to be consistent with the concepts of the quoted sentence above from footnote b of Table 1 of the existing TPL standards. There are many instances where some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs with the cost and environmental impacts of providing a higher level of reliability in a local area. An attempt to eliminate the concepts contained in footnote bof the existing TPL standards would invalidate local regulatory decisions, place a large unintended cost burden on existing customers and could potentially create criteria that could not be met anytime soon, if ever, as a result of the long lead time required for system improvements. Any attempt to raise the bar by interpreting the definition of Non-Consequential Load as eliminating the concepts of footnote b is considered unacceptable. The new criteria need to clearly maintain these concepts to prevent a large disconnect with existing design criteria. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, please move this sentence to the Notes Section at the beginning of Table 1 as new Item 7.

Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply.

The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.7.4) if a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe.

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

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions 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.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Organization	Question 3:	Question 3 Comments:
Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements. "1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity's existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase "permit operating steps necessary to maintain system control" and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss."		
National Grid	No	a. In the Consequential Load Loss definition, the word 'source' needs to be defined or explained further since it is unclear. b. Non-Consequential references non-interruptible load. Non-Interruptible load should be defined. Suggest: "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." c. The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" d. The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. As proposed in the draft, Firm Transmission Service is treated equal to load. In New England and New York, we focus on stressing transfer limits across and within the systems. By so doing, we preserve the internal transfer capabilities by design rather than modeling specific contractual transfers, which may not stress the internal interfaces. The exception is for the inter-Area ties. For inter-Area ties, the import or export capability is comparable to a generating unit, which we believe is acceptable to interrupt. We therefore feel that it should be acceptable to interrupt Firm Transmission Service over inter-Area ties and that Firm Transmission Service shouldn't be treated equally with load. Suggested changes: Change "Consequential Load Loss" to "Consequential Interruption". Change the definition to "Load, Firm Demand, or Firm Transmission Service that is no longer connected ..."Change "Non-Consequential Load Loss" to "Non-Consequential Interruption". Change the definition to "Non-Interruptible Load, Firm Demand, or loss of Firm Transmission Service other than Consequential Interruption that occurs

Organization	Question 3:	Question 3 Comments:
		through manual (operator initiated), automatic operations (such as under-voltage load shedding, under-frequency load shedding, or Special Protection Systems), or uncontrolled loss of a local area which does not significantly impact the Bulk Electric System."
Central Maine Power Company	No	There are a few significant concerns with these definitions: The definitions should be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load should be defined as, "Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
NSTAR Electric	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made. There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows for the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should

Organization	Question 3:	Question 3 Comments:
		specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition to "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."
ISO New England Inc.	No	There are a few significant concerns with these definitions: The definitions need to be expanded to include interruption of Firm Transmission Service in a manner that is comparable to interruption of load; otherwise, Firm Transmission Service (FTS) is being treated in a manner that is superior to load. (The expansion of the definitions to include FTS would also address stated concerns associated with loss of radial or single facilities over which Firm Transmission arrangements have been made). There are perceived limitations to what constitutes Non-Consequential Load Loss. It must be clear that Non-Consequential load loss allows the cascading loss of a local area that does not adversely impact the BES. It would be impractical and unnecessary to anticipate that every such situation could be or needs to be managed by operator action or automatic control. Non-Interruptible load needs to be defined as," Demand that the end-use customer has not made available to its Load-Serving Entity via contract or agreement for curtailment." The Consequential Load definition should specify "Interruptible and Non-Interruptible Load that is no longer connected to a source?" The inclusion of "or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes)" confuses the definition of Consequential Load Loss, because of the imbedded exception for steady state performance. It seems that the intent of this provision is to recognize that this type of load loss could occur for either transient or steady state conditions and that Planning Assessments should not be required to remedy this type of situation. However, this does seem to be at odds with the application and stated acceptability of Consequential Load Loss as noted in Table 1. Note: Table 2 has no reference to the treatment of Consequential Load Loss. It may be helpful to address the transient load loss situation in a separate definition. Recommended Changes: Change "Consequential Load Loss" and definition to "Consequential Interruption - Load, Firm Demand, or Firm Transmission Service that is no longer connected?" Change "Non-Consequential Load Loss" and definition- "Non-Consequential Interruption - Non-Interruptible Load, Firm Demand, or Firm Transmission Service loss other than Consequential Interruption loss that occurs through manual (operator initiated), automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems, or uncontrolled loss of a local area which does not significantly impact the BES."

Organization	Question 3:	Question 3 Comments:
Orlando Utilities Commission	No	The definition refers to "A source" which implies that an area served by several sources that loses access to one source could lose some load since it lost "a source" or "its source". This is a different meaning then the one expressed on the national conference call. As written this definition also implies that the triggering of a UVLS, UFLS or load shedding SPS is not acceptable under the conditions for which non-consequential load loss is not allowed. If the Drafting team's intent is to forbid the use of these devices for certain levels of contingencies then it should be done directly in the standard not hidden in a definition. (While an SPS may or may not include load loss, UVLS and UFLS are effective because of the load loss.)
Response: Definitions have been changed to clarify the definition of Consequential Load Loss. The reference to 'source' has been eliminated. The SDT does not believe that a definition for Non-Interruptible load is necessary because Interruptible Load is defined. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
OPUC	Yes and No	The concept of Consequential Load Loss is generally acceptable. However, the presentation, notes and cross referencing need to be adjusted to avoid confusion.
Response: The SDT has reviewed references for consistency as part of the changes made in response to the comments received in this posting.		
JEA	Yes	Recommend changing "Non-Interruptible Load" to "non-Interruptible Load" (first occurrence of use in the new definition.

Organization	Question 3:	Question 3 Comments:
Response: The first use is at the beginning of a sentence and the SDT feels that the term is correctly capitalized.		
PacifiCorp	Yes and No	? We generally agree with the definition but have concerns about a potential unintended consequence. This definition will severely limit the loads that can be classified as ?local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems? in footnote b of the existing TPL standards. In combination with raising the bar for loss of Facilities with operating voltages 300 kV or higher (P2, P4 and P5 in the Performance Tables), this definition may result in encouraging entities to connect more loads in a radial fashion or avoid loop connection to improve service reliability just to fit in the Consequential Load Loss definition, ??load no longer being connected to a source??. At a result, service reliability to customer would be adversity impacted without commensurate improvement in overall system reliability.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. However, if Systems are upgraded such that Load is not interrupted for first Contingency events, then there will be improvements to the overall reliability of the System.		
Progress Energy Florida, Inc.	No	The Definitions of ?Consequential Load Loss? and ?Non-Consequential Load Loss?, bring to mind the following concerns: Both Definitions are confusing and unclear as to their intent and meaning, and as presently worded it is PEFs belief that these particular Definitions can be interpreted in ways not intended by the SDT. For example, the definition of Consequential Load Loss contains the phrase "Load that is no longer connected to a source"; presumably this means "Load that is no longer connected to any source", but is not stated as such. PEF would note, however, its disagreement with the definition even with the wording change, given how the definition would be applied. UVLS, UFLS and SPS schemes are excluded from Consequential Load Loss, and thus are not allowed as mitigations for several outage scenarios. The SDT is essentially discouraging Transmission Owners from constructing such schemes, which is counterproductive to reliability, and actually reduces reasonable options left for Transmission Owners to the point that possible outcomes might be a) radializing of systems or b) removing breakers in order to convert load previously deemed Non-Consequential Load into Consequential Load. PEF maintains that where particular outage scenarios dictate the need for UVLS, UFLS and SPS schemes, the right to implement them should be allowed regardless of the category of event, so long as implementation in lieu of a more expensive project will not compromise the reliability of the BES. Whether or not UVLS, UFLS and SPS schemes continue to be categorized as Non-Consequential Load Loss, however, PEF disagrees with the definition given how it would be applied.
Response: With regards to the disincentives of the Consequential Load definition, the Standards do not specify how an entity will comply. The SDT has made changes to the definitions and has clarified acceptable loss of Load situations. This includes moving the last sentence of the Consequential Load definition to the Table. However, FERC Order 693 Section 1773 does not permit loss of Non-Consequential Load (see reference). There is no provision in the FERC Order to allow loss of Load with the use of an RAS/SPS or to provide exceptions for local networks. Our interpretation of the Order is that FERC is indicating that other alternatives must be pursued to avoid loss of Non-Consequential Load. However, the SDT has provided an exception (Requirement R2.6.4) if		

Organization	Question 3:	Question 3 Comments:
a situation arises that is beyond the control of the Transmission Planner or Planning Coordinator that prevent the implementation of a Corrective Action Plan in the required timeframe. “1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of the entity’s existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase “permit operating steps necessary to maintain system control” and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.” The definition of Non-Consequential Load Loss has been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~		
Lafayette Utilities System	No	Non-consequential load loss is described as including non-interruptible load lost that results from manual or automatic operations "such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems ?." It should be clarified that the quoted items are not intended to be exhaustive of the non-manual Load loss situations that would be considered the loss of Non-consequential Load. For instance, some types of industrial applications that are power-quality dependent may be expected to disconnect or shut down in the event of fluctuations in frequency, voltage or current. Foreseeable load interruptions of this nature should be treated as "Non-consequential Load loss" even if the mechanism by which the load disconnects is other than a UFLS, UVLS or SPS system operated by the Distribution Provider.
Response: The definition of ‘Consequential Load Loss’ has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load’s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.		

Organization	Question 3:	Question 3 Comments:
Non-Consequential Load Loss: Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Exelon Transmission Planning	No	UVLS should be allowed for in the definition of non-consequential load shedding in certain lower probability contingencies above 300 kV. The complete disallowance seems to disincentive their use, contrary to the NERC Blackout Recommendation 13c. There is a value in their use for certain voltage stability situations. There does not appear to be any limit (except no cascading) to the amount of acceptable load loss once non-consequential load loss is allowed.
Response: Recommendation 13c appears to be focused on reviewing practices. It does not appear to make a recommendation relative to any of those practices. **"**Recommendation 13c: The Planning Committee, working in conjunction with the regional reliability councils, shall within two years reevaluate the criteria, methods, and practices used for system design, planning, and analysis; and shall report the results and recommendations to the NERC board. This review shall include an evaluation of transmission facility ratings methods and practices, and the sharing of consistent ratings information. Regional reliability councils may consider assembling a regional database that includes the ratings of all Bulk Electric System (100-kV and higher voltage) transmission lines, transformers, phase angle regulators, and phase shifters. This database should be shared with neighboring regions as needed for system planning and analysis. NERC and the regional reliability councils should review the scope, frequency, and coordination of interregional studies, to include the possible need for simultaneous transfer studies. Study criteria will be reviewed, particularly the maximum credible contingency criteria used for system analysis. Each control area will be required to identify, for both the planning and operating time horizons, the planned emergency import capabilities for each major load area." As a result, it is unclear whether the proposed Standard is actually contrary to the recommendation as you suggest. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
MidAmerican Energy Company	No	MEC notes that Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss.
MRO NERC Standards Review	No	Non-Consequential Load Loss is defined by the SDT to include load dropped by Special Protection Systems while Consequential Load Loss does not exclude load dropped by Special Protection Systems. The SDT should resolve this

Organization	Question 3:	Question 3 Comments:
Subcommittee		contradiction between these two definitions by adding an appropriate reference to Special Protection Systems in the Consequential Load Loss. For Consequential Load Loss definition, The MRO suggests that the last sentence be deleted because it is application text, rather than definition text.
Response: The definition of ‘Consequential Load Loss’ and ‘Non-Consequential Load Loss’ have been revised to make them more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load’s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
SERC Dynamics Review Subcommittee	Yes	The modified definitions of Consequential load loss has been appropriately modified to include loss of Load as a result of the Load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the resulting Load dynamics will result is loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected real world loss of load is acceptable. It is also proper that the computation of expected consequential Load loss and duration is not required for single contingency stability analysis. If there is a need, Load loss due to the resulting transmission system configuration would be captured by steady state analysis. Attempts at determining additional Load loss due to load dynamics would not result in any useful information contributing to increased reliability.
Response: In response to other industry comments, the SDT has added a new definition which covers the loss of Load due to Load dynamics - Supplemental Load Loss. It is no longer included as part of Consequential Load Loss. In dynamic studies, Supplemental Load Loss is allowed for any planning or extreme event. The tabulation of Load lost due to a Contingency does not include Supplemental Load Loss.		
Arkansas Electric Coop. Corp.	No	These definitions are still confusing. I offer the following example to explain: If you have a networked transmission line serving several loads, a fault occurs on the line, and the load is dropped because of the line breakers at either end of the line operating. As a result the operator would normally sectionalize the line and isolate the faulted section. This results in the networked line now being two radials and the load is restored. From a planning standpoint the resulting steady state is

Organization	Question 3:	Question 3 Comments:
		the resulting two radials and there should not be any consequential load loss. From an operational standpoint steady state would have occurred at the time of the breakers opening and dropping the load. Operationally the load is consequential load loss. This being a planning standard the standard should require that all the load be served and the transmission line meet the (planning)steady state performance requirements. If the SDT agrees that the resulting radials should be capable of serving all the load and meet the planning steady state performance requirements then I can agree with the definition. If not then I disagree. In the planning environment systems should be studied and assessed based on an switchable element to switchable element basis and not just breaker to breaker. on-Consequential Load Loss - 1. Is it the intent of the SDT that Non-Consequential Load Loss be all firm load other than Consequential Load Loss? If not it should be. Is there a definition of "Non-Interruptible Load"? Didn't see it in the Glossary. 2. additional language should be added stating that the examples given are not inclusive. I have a problem with NERC providing examples in definitions because often the examples are interpreted as the definition itself when in reality their purpose is to clarify.

Response: In your example**,** Consequential Load Loss occurs with the initial event. The standard does not address the size of the Consequential Load or whether alternative sources are required to restore Consequential Load Loss.

Non-Consequential Load is intended to be Firm, which is evident by FERC Order 693 which states:

“1773. The Commission proposed in the NOPR to approve Reliability Standard TPL-002-0 as mandatory and enforceable. In addition, pursuant to section 215(d)(5) of the FPA and § 39.5(f) of our regulations, we proposed to direct NERC to submit a modification to TPL-002-0 that: (1) requires that critical system conditions be determined in the same manner as proposed for TPL-001-0; (2) requires the inclusion of the reliability impact of

the entity’s existing spare equipment strategy; (3) explicitly requires all generators to ride through the same set of Category B and C contingencies as required for wind generators in Order No. 661; (4) requires documentation of load models used in system studies and supporting rationale for their use; (5) clarifies the phrase “permit operating steps necessary to maintain system control” and (6) clarifies footnote (b) to Table 1 to allow no firm load or firm transactions to be interrupted except for consequential load loss.”

The definition of ‘Consequential Load Loss’ has been revised to make it more direct. New definitions have also been created to recognize other forms of acceptable Load loss that might occur in response to an event.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load’s response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load’s response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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.

Organization	Question 3:	Question 3 Comments:
Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. The SDT didn't feel non-Interruptible Load needed to be defined because Interruptible Load is a defined term		
Tri-State Generation and Transmission Association, Inc.	Yes	We agree with the definitions in concept - that Consequential Load Loss is load which would be unserved following a specific outage event, without any load shedding relay operations. However, there is some ambiguity in how things are defined for N-1-1 contingencies. For example, a firm contract or firm resource would not be automatically curtailed upon the first outage (N-1), but operators may need to curtail the contract or resource schedule to restore the system to acceptable operating limits, or arm relay schemes that would interrupt certain facilities for the second outage (N-1-1). It seems unreasonable that some such operator actions would not be allowed.
Response: The SDT has revised the definitions and tables to provide greater clarification on what can be curtailed. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~ are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
AEP	No	Should clarify that it's load that is no longer connected since the transmission facilities to which it is connected have been outaged as expected by the normal relay response to the event being studied. In other words, the loss of load that is connected to facilities that have cascaded as a result of the event being studied is not consequential load loss (nor is it non-

Organization	Question 3:	Question 3 Comments:
		consequential load loss). See load loss definitions under Attachment D of PJM Manual 14B for additional wording suggestions.

Response: The definition of 'Consequential Load Loss' has been revised to make it more direct, which clarifies that the causal event is a 'fault' that is cleared by 'planned protection system operation'.

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

Organization	Question 3:	Question 3 Comments:
Lakeland Electric	No	Recommend: Consequential: Load that is no longer served because its electrical path to the BES is open as a direct result of system response to the event under study. Load lost due to event induced transients is Consequential load loss; however, the this load must be included in the model during steady-state analysis. Load lost due to UFLS, UVLS, Special Protection Schemes and operator actions are not considered Consequential. Non-Consequential: Load that is no longer served for any reason other than those identified in the definition on Consequential.

Response: The SDT has made changes to the definitions which are conceptually consistent with your suggestion.

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

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions 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.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Organization	Question 3:	Question 3 Comments:
Southern Company Transmission	Yes and No	Yes on the definition. The definition of Consequential Load Loss has been appropriately modified to include loss of load as a result of the load's response to the transient condition. This recognizes the fact that when subjected to fault voltages of sufficient depth and duration, the load undervoltage protection will result in loss of Load. Therefore, in order to more accurately replicate real-world behavior through dynamic stability simulation analysis, the proper representation of expected

Organization	Question 3:	Question 3 Comments:
		real world loss of load is acceptable. No on R3.3.2.1 dealing with Consequential Load. The computation of expected consequential load loss and duration does not result in any useful information contributing to increased reliability. Therefore, this requirement R3.3.2.1 should be dropped. If the computation is not deleted, at least the duration part of it should be dropped. In a Planning analysis, the duration is indeterminate.
Response: New definitions have been created to recognize other forms of acceptable Load loss that might occur in response to an event. The calculation of the potential Load loss for anything other than Consequential Load Loss is not required and the analysis is not expected to include it (see new 'Supplemental Load Loss' definition). However, a calculation of the maximum expected contingent Consequential Load Loss is expected (see Requirement R2.9). Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required and 'duration' has been dropped. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
North Carolina Electric Membership Corp	No	Although the modified definitions are an improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events, except P0 (normal)? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider

Organization	Question 3:	Question 3 Comments:
		changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)? Perhaps examples of each are needed: Consequential Load Loss examples might be a) tapped load from an outaged networked line from main station breaker to main station breaker of entire line, b) outaged T/T transformer serving radial load that that taps the networked transmission line, c) load served from a radial feeder from a single source. Non-consequential might include a) manual load dump or generator trip to mitigate cascading or uncontrolled load loss or an overload during adverse conditions, b) SPS addressing above, c) UFLS, d) UVLS.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	Comments: Although the modified definitions are a good improvement over the previous version, addressing the following issues in the Consequential Load Loss definition will further improve clarity:1) Redundancy: The second sentence in the definition says "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,?". It appears that "?and is permitted when Consequential Load Loss is allowed,?" is redundant and may be omitted/deleted -- isn't this *always* permitted for all events? (See head note 4 in Table 1 -- Steady State Performance). 2) Who are the "planning entities"? Suggest replacing with Functional Model terms Transmission Planner and Planning Coordinator. 3) Verbosity: It appears that the intent of the second sentence in the definition can be conveyed more concisely. Consider changing to "However, relying upon the expected Load loss during transient conditions of the event to meet steady state performance requirements is not allowed." 4) If the verbiage proposed above is found acceptable, we offer a follow-up suggestion. Because the second sentence in the definition essentially characterizes the exception to the allowed Consequential Load Loss during steady state performance evaluation, we suggest moving it out of the definition and appending it within head note 4 in Table 1 -- Steady State Performance. 5) While the Consequential Load Loss definition employs the acronyms UFLS and UVLS, their expanded descriptions have been used in the Non-Consequential Load Loss definition. Suggest that these terms be used consistently in both

Organization	Question 3:	Question 3 Comments:
		definitions. Also, why is Special Protection Systems included as an example of what constitutes Non-Consequential Load Loss but is excluded from the list of exceptions to Consequential Load Loss (whereas UVLS and UFLS appear consistently in both)?
Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestions. The revised definitions are more direct and eliminate examples. The reference to Planning Entities has been deleted. The definition of Non-Consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
ERCOT System Planning	No	ERCOT feels the amount and duration of load loss should be considered in the definition.
Response: Requirement R3.3.2.1 has been rewritten as Requirement R2.9 to more specifically identify what is required. As part of that review, the consensus was that duration is too difficult to accurately prescribe and had no value in a Planning Standard and has been dropped. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.		
Alberta Electric System Operator	No	We generally agree with the definitions by themselves but have concerns about regarding application, please refer to response in Q15. The last sentence in the Definition of Consequential Load Loss (?Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of

Organization	Question 3:	Question 3 Comments:
		such Load loss to meet steady state performance requirements?) seems more appropriate to be requirements. Therefore, recommend moving this sentence to the Notes Section at the beginning of Table 1 as new Item 7.
Response: Definitions have been changed to clarify Consequential Load Loss and the last sentence in the definition has been moved to the tables. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Note "b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~ are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		
FirstEnergy Corp.	No	Regarding the definition of "Consequential Load Loss" we do not agree with the inclusion of Load which is lost as a result of the Load's response to the transient conditions of the event and recommend that the team restrict the definition to account for only load which is directly served by the facilities which were de-energized as a result of the contingency event. To include this within in the definition seems counterproductive to the planning of the transmission system that is required by this reliability standard. Comments on other definitions:1) Planning Coordinator (PC) ? The SDT included a new definition for PC for inclusion in the NERC Glossary of Terms. We agree that this addition better aligns the Glossary with the PC applicable entity which is prevalent in a variety of standards. However, we are curious why the SDT did not indicate a deletion of the Planning Authority (PA) definition and what steps, if any, are being made by NERC to align registry criteria which uses Planning Authority (PA) to the reliability standards use of the PC. 2) Year-One: The definition for Year-One is awkwardly written. We suggest that the definition be adjusted to read "The planning year that begins with the upcoming annual period under study". 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. 3) BES ? The acronym BES is used throughout the standard but never defined. We suggest this could easily be done in

Organization	Question 3:	Question 3 Comments:
		the purpose statement by simply adding the text "(BES)" after the reference to Bulk Electric System.

Response: Definitions have been changed to clarify Consequential Load Loss.

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

The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

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.

Bulk Electric System will be spelled out in the first reference.

Organization	Question 3:	Question 3 Comments:
Entergy Services, Inc.	No	To the extent stakeholders agree with the use of UVLS or other special protection systems to mitigate events and avoid costly infrastructure improvements, the load that is reduced due to the operation of these systems should be capable of being classified as consequential load. In some cases, these systems can enhance grid reliability by removing components that have no significant impact on the BES. The definition of Non-consequential Load Loss includes load dropped by UVLS, UFLS, as well as SPS. However, Consequential Load Loss does not name SPS load loss as an exception, while UVLS and UFLS are named specifically. Shouldn't load lost by SPS action also be included in this exception to reduce confusion? There also seems to be another category missing. Non-consequential load loss could also be a result of "regular" protection systems beyond those directly protecting the faulted equipment. The second part of the Consequential Load loss definition is confusing - "Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements." While it Is part of consequential load loss per the definition, planners are not allowed by the standard to plan for it. Therefore, this definition seems to make the Performance Tables incorrect. With this statement we seem to need another term like "Allowable Consequential Load loss."

Response: The SDT has made changes to the definitions and text, which are conceptually consistent with your suggestion. The definition of Non-consequential Load Loss has also been changed to remove the reference to UFLS and UVLS, which are systems used for operations and are not applicable to a planning standard. Examples have been removed from definitions.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response~~

Organization	Question 3:	Question 3 Comments:
~~to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
BPA Transmission Reliability Program	No	The definition of Consequential Load Loss needs to be modified to include all of the concepts that were contained in footnote b of the existing TPL standards.
Response: "All of the concepts that were contained" are subject to interpretation and there are different interpretations of what the concepts are. Therefore it is not clear what you would like to see. The SDT has continued to revise the definitions in response to the comments received subsequent to the second posting. Notes have been added to provide conditions and clarifications relative to the interruptions of Firm Transmission Service. Hopefully these changes will address your concerns. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions 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. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions. **Note 'b":** Consequential Load Loss, Supplemental Load Loss, Load Reduction, and consequential generation loss ~~is allowed for all events shown.~~ are acceptable as a consequence of any Planning or Extreme Event excluding P0. However, Supplemental Load Loss associated with an event shall not be used to meet steady state performance requirements.		

Organization	Question 3:	Question 3 Comments:
PPL EnergyPlus	Yes	The SDT conference call was helpful to my understanding of non-consequential. As I understand it, non-consequential load loss allows transmission planners to drop load that chooses to be dropped under certain conditions. This is a useful tool as not all loads demand the same quality of service.
Response: Yes, interruption of Interruptible Load is acceptable.		
City Water, Light & Power - Springfield, Illinois	Yes	
Platte River Power Authority	Yes and No	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Florida Power and Light	Yes	None.
Austin Energy	Yes	
LCRA TSC	Yes	

Organization	Question 3:	Question 3 Comments:
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
Duke Energy	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response. However, the majority of commenters requested changes to the definitions which can be seen in the summary response above.		

4. The SDT has modified Requirement R3.5 and eliminated Requirement R3.6 from the first draft to clarify that manual and automatic generation run-back (redispatch) and tripping is allowed as a Corrective Action Plan as long as the conditions in Requirements R3.5.1, R3.5.2 and R3.5.3 are met. Do you agree that generation run-back and tripping (manual and automatic) should be limited by these conditions? If not, please explain why you disagree with the proposed requirements.

Summary Consideration:

By a nearly unanimous response the industry agrees with the modification to Requirement R3.5 in the latest draft that allows manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. However, in response to the question, only a small percentage of the commenters supported the current modification including the conditions in Requirements R3.5.1, R3.5.2, and R3.5.3 without reservation. A wide variety of changes, additions and clarifications to these conditions were suggested.

The SDT agrees with the industry's majority view that the Sub-requirement conditions for manual and automatic generation run-back or tripping as a response to a single or multiple Contingency and the Sub-requirement conditions for automatic generation tripping as a response to mitigate Stability violations are applicable to all requirements of the TPL Standard and are already stated elsewhere in the Standard or should be eliminated because they are specified in other ways, including national codes such as OSHA and NESC. Consequently, these conditions, specified in Requirements R3.5.1, R3.5.2, and R3.5.3 have been removed from this third draft.

In summary, due to industry comments in response to this question, the SDT changed the following requirements and footnote:

R2.7.1. (now R2.6.1)– added bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.7.1. (now R2.6.1)– added bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

R3.2 (now R3.3 and R3.3.1) Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

R3.2.1 (now R3.3.2) For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Footnote #10 – 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 be considered.

In addition, the following requirements have been deleted:

R3.5 ~~Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency if the following conditions are met~~

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

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

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

R5.4.3 ~~Automatic generation tripping is allowed to mitigate Stability violations if the following conditions are met:~~

R5.4.3.1 ~~All Facilities shall be operating within their Facility Ratings~~

R5.4.3.2 ~~Such action would not violate safety, equipment, regulatory or statutory requirements~~

R5.4.3.3 ~~A sustainable, stable, operating condition is maintained~~

Organization	Question 4:	Question 4 Comments:
Dominion - Electric Transmission Planning	No	We generally agree with the modification, but feel that further clarification needs to be added as follows -- "Neither generation run-back (redispatch) nor tripping should be allowed to address deficiencies identified in single contingency (N-1) studies should the full output of the generation choose to be considered as a capacity resource". Should generation run-back be allowed, then a NERC Reliability Standard should be developed to require generator field testing to prove that generation run-back is a viable solution.
Duke Energy	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.
Progress Energy Carolinas	Yes	Furthermore, PEC believes that generation run-back and tripping should not be allowed as a CAP for N-1 events with the possible exception of small reductions of generation.

<table>
<tr><th>Organization</th><th>Question 4:</th><th>Question 4 Comments:</th></tr>
<tr><td>BCTC</td><td>Yes</td><td>We agree that runback/tripping should be permitted for all contingencies. However, we are concerned that listing runback/tripping as an acceptable alternative, at least as currently worded, may encourage use when system reinforcements should be built. BCTC would prefer TPL-001 to be silent on this issue and that R3.5 be deleted. The list of conditions is very generic and should apply to all of TPL-001. If R3.5 is retained, the list of conditions should also require that all generation reserves requirements are met.</td></tr>
<tr><td>ITC Holdings: ITC, METC, ITC Midwest</td><td>No</td><td>We do not believe that generation runback or tripping should be a CAP for a single contingency. This is particularly true if the generation scheme puts the system one contingency away from another potential condition requiring corrective action, such as load shedding. At a minimum R3.5.3 needs further definition as to what a ?sustainable, stable, operating conditions? is. For example, creating another N-1 scenario is not a sustainable condition. Allowing for SPS is not raising the bar.</td></tr>
<tr><td>AEP</td><td>No</td><td>Generator tripping should not be regarded the same as generator runback. With tripping, a resource is lost from the system and there is no assurance that it can be restored to service within a reasonable time. Runback allows the resource to stay connected and the original MW level is potentially restorable if the precipitating factors for runback can be resolved. The generator may be valuable for MVAR as well as MW. The existing TPL standards imply that generator tripping is not permissible in connection with Category B events in that Table 1 footnote b does not mention it, whereas it is mentioned in connection with Category C events in footnote c; we agree with this. Generation is a system resource and should be protected against the more common single contingency transmission events. We would like to see the present implied restriction on generator tripping following single contingencies to be maintained and clearly articulated in the new standard, with a provision for regional variance. In contrast to tripping, what the standard has now for manual or automatic runback in R3.5 is okay.</td></tr>
<tr><td colspan="3">Response: By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. Therefore, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1- bullet #3.

R2.6.1. – bullet #3: <u>Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.</u>

R2.6.1. – bullet #4: <u>Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.</u></td></tr>
<tr><td>NPCC</td><td>No</td><td>We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."</td></tr>
<tr><td>Northeast Utilities</td><td>No</td><td>Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.</td></tr>
</table>

Organization	Question 4:	Question 4 Comments:
TVA System Planning	Yes	Suggest applicable voltage limits must also be maintained during runback and tripping.
National Grid	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. We suggest adding a paragraph which be numbered 3.5.4 and would read "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Tenaska, Inc.	Yes	R.3.3.2.2 needs some re-wording to clarify that generator runback (re-dispatch) and tripping are allowed.
Gainesville Regional Utilities	No	R3.5.3 is somewhat ambiguous. We need clarification as to whether the system needs to prepare for the next contingency (a secure state) or whether it needs to be maintained in a stable operating condition which is sustainable but not secure.
Hydro-Québec TransEnergie (HQT)	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
Central Maine Power Company	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping shall not impose undue complexity and risk to the operation and reliability of the system."
NSTAR Electric	No	R3.5.1, R3.5.2 and R3.5.3 are not limiting enough. Add paragraph 3.5.4 "Automatic generator tripping schemes shall not be overly complex and risk to the operation and reliability of the system." Complex SPSs or multiple installations of SPSs can have an adverse impact on the ability to reliably operate the system, especially during maintenance outage conditions.
New York Independent System Operator	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have an Adverse Reliability Impact."
ISO New England Inc.	No	We do not feel that R3.5.1, R3.5.2 and R3.5.3 are limiting enough. Add paragraph 3.5.4 "Manual and automatic generator tripping shall not have a significant adverse impact on the system."
Response: The SDT appreciates your suggested improvements. However, the SDT has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1- bullet #4. Likewise, the SDT has		

Organization	Question 4:	Question 4 Comments:
modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet# 3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
City Water, Light & Power - Springfield, Illinois	Yes and No	There should be a time limit for manual generation runback.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – 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 be considered.		
Manitoba Hydro	Yes	Manitoba Hydro commends the SDT for recognizing that generator run-back and tripping is a valid option in the transmission planner's tool box, not unlike more expensive devices such as FACTs devices. Can the SDT confirm that the conditions in R3.5.1, R3.5.2 and R3.5.3 apply to post generator tripping period. R3.5.2: The references to safety violations and equipment requirements are very generic. It is difficult to imagine what type of safety violation may be caused by a generator trip considering this is a widely used practice in many regions. The SDT should also be more specific as to what is meant by "equipment requirements". The requirement to be within Facility (equipment) Ratings is already covered in R3.5.1. Manitoba Hydro recommends the to "safety, equipment" be deleted from R3.5.2. Other Requirement R3 Comments:R3: In the first sentence, "perform analysis? should be changed to "perform studies? and the word ?studies? after Horizon should be deleted. R3.2: Delete the words ?including those?. R3.2.1: Can the SDT clarify what is required? Is the requirement to ensure the generator undervoltage ride through is not violated? If so, Manitoba Hydro recommends overvoltage ride-through (maximum voltage) should also be added. Also, is ?For all Generators? and ?of all generators? both needed?

Organization	Question 4:	Question 4 Comments:
		R3.3.1: Appears to be a repeat of R3.1.R3.3.2: R3.3.1 requires performance criteria to be met for Planning Events, which includes both single and multiple contingency events. Doesn't R3.3.2 repeat R3.3.1? R3.3.2.1:The requirement to report duration of the Consequential Load Loss would be a wild guess as the duration will relate to the nature of the event, so Manitoba Hydro questions the value. For example, the event is a simple lightning hit on a line, the restoration time is expected to be short, but if the cause of the line loss is a tornado that takes down structures, it could be days. Can the SDT clarify the requirement. R3.3.2.2: Are ?Transmission reconfiguration changes and redispatch of generators? only allowed for single contingencies? Is redispatch allowed if such redispatch results in curtailment of Firm Transmission Service? R3.3.2: It appears that R3.3.2 can be deleted, and its subrequirements placed under R3.3.3: The contingencies that ?are expected to produce more severe System impacts? are very likely multiple contingencies. Since there are numerous combinations of multiple contingencies, it is an impossible task to explain why the ?remaining Contingencies were not selected. If this is not the intent, can the SDT explain what is required? The requirement should simply allow the planner the discretion to use judgment to select these more severe Contingencies, and the elements they are applied to, with explanation as to why they are expected to be more severe.

Response: The SDT has eliminated these conditions in Sub-Requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-Requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-Requirement R3.5 for Contingency events and relocated to become Sub-Requirement R2.6.1. Likewise, the SDT has modified Sub-Requirement R5.4.3 for Stability events and relocated to become Sub-Requirement R2.6.1.

R3.5.2 – The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3.

R2.6.1. – bullet #3: Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.

R2.6.1. – bullet #4: Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

The SDT appreciates your suggested changes to Requirement R3 but after reviewing the suggestion has decided that the original wording is correct.

Your suggested change to Requirement R3.2 (now Requirement R3.3.1) has been adopted.

R3.3.1 Contingency analyses shall simulate the removal of all elements ~~including those~~ that the Protection System ~~protection is~~ and other automatic controls are expected to disconnect for each contingency without operator intervention.

Requirement R3.2.1 (now Requirement R3.3.2) is intended to require realistic representation in simulations of whether a generator will trip due to low voltage; it is not a requirement that the generator be able to ride through a low voltage condition. Your suggested deletion was accepted.

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R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation. Regarding your comments on old Requirements R3.3.1 and R3.3.2, there is a subtle difference. Requirement R3.3.1 addresses performance criteria, while Requirement R3.3.2 deals with the Contingencies that need to be evaluated and to which the performance criteria should be applied. The requirement to report duration of Consequential Load Loss in R3.3.2.1 (now Requirement R2.9) has been removed from this draft. **R2.9** The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1. Curtailment of Firm Transmission Service is explained in the new footnote #10 in the Table. **Footnote #10** – 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 be considered. The SDT has considered your comments regarding the requirement to explain why less severe Contingencies were not selected; however, there were few other comments that raised this concern, and the SDT has retained the original language.		
Los Angeles Department of Water and Power	Yes and No	R3.5.1, 3.5.2, and 3.5.3 are redundant and already covered in other standards or safety codes such as FAC, TOP, OSHA, NRC, NESC, etc. If these kind of "reminder" is required here just to make sure planners do not ignore all the relevant codes, then it could also be argued that an absence of such reminders in other section would mean that these codes do not need to be observed unless they are specifically called out. I think they should all be deleted to avoid such twisted argument but potential loopholes.
Transmission Agency of Northern California	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Pacific Gas and Electric Co.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability

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		study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Public Service Company of New Mexico	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
JEA	Yes and No	R3.5.1 JEA does not understand what measure will be applied to determine that Facility Ratings were not violated during the generator run-back period.R3.5.2 JEA does not understand what measure will be applied to determine compliance that generator trips and runbacks will not violate safety, equipment, regulatory, or statutory requirements.R3.5.3 JEA does not understand what is meant by the word "Sustainable". Needs a practical definition.
PacifiCorp	Yes and No	? We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Puget Sound Energy, Inc.	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Idaho Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.

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SMUD	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables. Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds?
Progress Energy Florida, Inc.	No	PEF does not disagree with the conditions described in Requirements R3.5.1, R3.5.2 and R3.5.3 when taken in particular contexts. PEF, however, is compelled to check "no" for this question due to the fact that no specification has been made as to when such CAPs can be applied. PEF feels that the CAPs specified (as well as the curtailment of Firm Transactions and Non-Consequential Load) should be allowed following any N-1 event, and also as system adjustment actions in between the two events of a P6 event. Given that no such specification has been made here, PEF objects to the wording, and suggests that the language be modified to clarify that the application of these CAPs are allowable after N-1 events and in between the two events of Event P6.
Sierra Pacific Power Company / Nevada Power Company	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Black Hills Corporation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Arizona Public Service Co.	Yes and No	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other

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		Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest moving R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Florida Power and Light	No	The sub-requirements of R3.5 are not clear as to whether the conditions apply to before or after generator run-back/tripping and mixes together N-1 and N-2 contingencies. In addition, the phrase "sustainable, stable, operating condition" in R3.5.3. is ambiguous as to whether it means the system is secure (prepared for the next contingency), or the system is maintained in a stable operating condition which is sustainable but not secure.
Exelon Transmission Planning	Yes and No	We agree that manual and automatic generation run-back and tripping should be allowed in these situations. We do not agree with the portion of R3.5.2 that states that non-compliance would result if the action were to violate statutory or regulatory requirements. A local governmental body could impose a restriction that would then trigger NERC compliance issues without independent or sufficient review. Other regulatory entities have their own enforcement mechanisms. It should be clear that SPSs, by definition, are allowed for other purposes than generation runback or tripping (such as system reconfiguration with automated breaker operation).
SRP	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Tucson Electric Power Company	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
SERC Dynamics Review Subcommittee	Yes	Generation run-back and tripping should be allowed and the proposed sub-requirements are appropriate.

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Modesto Irrigation District	Yes	Comments: We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Midwest ISO	Yes and No	Under the subrequirement of R3.5.2 it may not be possible for the PC/TP to determine whether the safety, equipment, regulatory or statutory requirements are violated without collaboration with the Transmission Owner and/or the Generator Owner. Therefore, if this subrequirement is retained it should be amended to include the following sentence: "Applicable Transmission Owners and/or Generator Owners shall collaborate with the PC/TP in determining whether such action would violate safety, equipment, regulatory or statutory requirements".
Tri-State Generation and Transmission Association, Inc.	Yes	Agree with the described corrective actions, but wonder whether the sub-requirements R3.5.1 - R3.5.3 must be specifically listed.
Tri-State G&T	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Southern Company Transmission	No	Generation run-back and tripping should be allowed and most of the proposed sub-requirements are appropriate. However, R3.5.2 is overly broad. We suggest that regulatory and statutory requirements should be deleted from R3.5.2.
NERC and Regional Coordination	No	Delete R3.5.2 as redundant. The limit data provided by the asset owners is expected to ensure that safety, equipment, regulatory and statutory requirements are met. For example to require the PC to ensure that equipment is not at risk would require the PC to make financial decisions that belong to the asset owner (e.g. the owner may be willing to exchange loss of equipment life for short term financial gains).R3.5.3 - the term sustainable, stable condition is not defined. Further the

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		maintenance of such a state is beyond a PC's capability.
ColumbiaGrid	Yes	We generally agree, however, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
IESO	Yes and No	We agree with the conditions stipulated in R3.5.2 and R3.5.3 but do not agree with R3.5.1. This is one of the performance objectives that the use of manual and/or automatic generation run-back/tripping is intended to achieve, and it is already stipulated in Table 1. Suggest to remove this condition.
Southern California Edison	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
North Carolina Electric Membership Corp	Yes and No	The generation run-back/trip should not put any load or firm transfer at risk of also being harmed. Maybe this is implied within the conditions required.
ERCOT System Planning	No	The requirement is unclear whether runback is allowed if the conditions are met or if runback is allowed to meet the conditions. What is the need for generation run-back/tripping if all facilities are within their Facility Ratings? Many times the run-back/tripping of units, such as wind farms, is necessary to remove a post-contingency overload associated with these units. The protection scheme includes the run-back/tripping to allow these units to generate at higher levels pre-contingency.
Florida Reliability Coordinating Council, inc	No	R3.5.1 ? This requirement should be clarified to state that all facilities shall operate within their Facility Ratings before, during and after system adjustments including generation adjustments.R3.5.2 ? How can an entity demonstrate that it is not violating this requirement.. The SDT should indicate the type of regulatory and/or statutory requirement that this requirement trying to address (i.e., FERC, EPA, etc.)?. Otherwise, the FRCC recommends removing R3.5.2.R3.5.3 ?The SDT should clarify this requirement to define what is meant by sustainable and stable. Sustainable and stable may not necessarily be the same as

Organization	Question 4:	Question 4 Comments:
		being in a secure condition (ready for the next possible event).
Alberta Electric System Operator	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest R3.5 and R3.4.3 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
Orlando Utilities Commission	No	The requirement R3.5.1 is not clear. If the intent is that following a single or multiple contingency facilities are within their ratings before, during and after the generation adjustment it's should be specified that way. "All facilities shall operate within their facility ratings prior to, during, and after the generation adjustment". Also I am unclear on how I would prove that I am not violating and safety or statutory requirements, that seems to be attempting to prove a negative since it is not specific on which requirements. Maybe ?Not violating any known safety and statutory requirements? if it is necessary to have this part. However since any real statutory and safety requirements have their own enforcement mechanism it is unnecessary to have the NERC auditor monitor these in addition to the existing monitors. I am not sure on the definition of sustainable? Is it a system that requires no further adjustment to be within it's long term ratings? Or is it a system that is prepared for the next event (Secure)?
Entergy Services, Inc.	Yes and No	The intent seems reasonable, but the wording needs work. There needs to be consistent verb usage. All 3 sub-bullets need to use "shall" instead of "would" and "is."
US Bureau of Reclamation	Yes	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables.
BPA Transmission Reliability Program	No	R3.5 is not a requirement, but an allowed action in order to meet performance criteria. Therefore, the statement about generation run-back/tripping in R3.5 should be moved to become part of the notes in the Performance Tables and not part of the requirements text. The conditions described under R.3.5.1 through R.3.5.3 are covered elsewhere in the standards and should be removed from this section. Since R3.5 and R5.4 contain some similar wording, also see comments relating to R5.4 under Item 2, above.
Response: The SDT agrees and has eliminated these conditions in Sub-requirements R3.5.1, R3.5.2 and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2 and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for		

Organization	Question 4:	Question 4 Comments:
Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
Lafayette Utilities System	No	Requirement R.3.5 states that generation run-back is allowed as a response to single or multiple contingencies, as long as certain conditions are met. Lafayette's concern is that the allowance for generation run-back is not limited to generation owned by the Transmission Planner or under the Transmission Planner's direct operational control. For that reason, the language could be interpreted to permit reliance (for planning purposes) on redispatch of generation owned by third-party generation owners that is undertaken in compliance with Reliability Coordinator directives during a Transmission Loading Relief event. During the SDT conference call held on August 26, 2008, the SDT representative stated that the team did not intend that R.3.5 would permit a Transmission Planner to rely on third-party generation redispatch, and that the intent was only to permit reliance on run-back (redispatch) of generation owned by or under the direct control of the Transmission Planner. Lafayette believes the language of R.3.5 needs to be clarified to state in express terms the limitation intended by the SDT. Reliance on third-party redispatch should not be permitted unless a Transmission Planner has entered into a contractual arrangement with the generation owner authorizing such use.
Response: The SDT agrees that if a Transmission Planner does intend to rely upon third party generation as an option to meet this requirement then the Transmission Planner's contractual arrangements between that Generation Owner and the Transmission Operator must be in place. However, the SDT does not believe that this needs to be stated as a Requirement in this Standard.		
Ameren	Yes	R3.5.1 should be modified as "All Facilities shall be operating within their applicable Facility Ratings, including the use of short-time emergency ratings."
E.ON U.S. Transmission Planning	Yes and No	R3.5.1 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating.
Response: As stated in Footnote 10 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings. **Footnote #10** – 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		

Organization	Question 4:	Question 4 Comments:
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.		
American Transmission Company	No	We generally accept this text, but would like the Facility Rating reference to include the applicable time frame (see response to Question 2.)
Response: As stated in Footnote 1 of Table 1, planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings.		
PPL EnergyPlus	Yes and No	My concern is that some TSPs over-use RAS and at some point, system improvements must take place. The best approach is a collaborative effort of all stakeholders (esp. operations folks) to prevent abusing RAS. Possibly R3.5 could tie to or be put under an Requirement that involves collaboration with stakeholders.
Response: The SDT has modified Sub-requirement R3.5 for Contingency events and relocated it to become Sub-requirement R2.6.1 – bullet #4. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become Sub-requirement R2.6.1 – bullet #3. Collaboration between the Transmission Planner and the Planning Coordinator is referenced in Requirements R5, R6, and R7. **R2.6.1. – bullet #3:** Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations. **R2.6.1. – bullet #4:** Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.		
OPUC	Yes	
US Army Corp of Engineers, Northwestern Division	Yes	
CenterPoint Energy and CPS Energy	Yes	

Organization	Question 4:	Question 4 Comments:
MidAmerican Energy Company	Yes	
MRO NERC Standards Review Subcommittee	Yes	
Austin Energy	Yes	
Lakeland Electric	Yes	
Brazos Electric Power Cooperative, Inc.	Yes	
LCRA TSC	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Platte River Power Authority	Yes	
Response: Thank you for your response.		

5. **The SDT has modified the modeling requirements. Some commenters expressed concern that the modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 were either duplicative of the requirements in the MOD standards, or to the extent new modeling requirements were proposed, that the appropriate venue for such modeling requirements would be the MOD standards. 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 also modified proposed modeling requirements contained in Requirement R1 of the first draft of TPL-001-1 based on industry comments and moved these requirements to Requirements R9 through R14 in the second draft for ease of removal later on. Furthermore, in response to industry comments, the SDT has separated the modeling requirements into individual requirements for each responsible entity. Do you concur with the modifications reflected in Requirements R9 – R14? If not, please state why and/or suggest specific changes..

Summary Consideration:

In response to industry comments, the SDT has removed requirements R9-R14 and enhanced requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC staff for inclusion in NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data.

The following requirements have been changed due to industry comments:

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~ Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as:

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices

- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 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 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 due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
Dominion - Electric Transmission Planning	Yes and No	For requirements R9, R12, R13, the wording should be changed from ..."shall provide its respective Planning Coordinator with modeling information ..." to "shall provide its respective Planning Coordinator and Transmission Planner with modeling information ..."
NPCC	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail, such as distribution network detail, is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial, commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
TVA System Planning	No	TVA provides the following comments: " Distribution Provider" in R9 should be replaced with "Load Serving Entity." Also in R9, is the expected mix of load to be presented individually or as a total of commercial, residential, and industrial loads? Would requiring this mix of load forecasts also result in a change to any MOD or FAC requirements dealing with

Organization	Question 5:	Question 5 Comments:
		load forecasts?" Transmission Planner" in R10 should be "Transmission Service Provider." Is this requirement also in MODs? In R11, R12, and R13 suggest adding "Transmission Planner" to "Planning Coordinator". In R13, Resource Planner may not have knowledge of Reactive Power devices and new technologies.
Manitoba Hydro	Yes and No	R1: Requirement R1 places the obligation for maintaining a model on the PC/TP. While the PC/TP can maintain data for its system(s), the models generally used for planning assessments are regional models developed and maintained by the Regions. Could the SDT explain its expectation of the scope and responsibilities of the model to be maintained? R9-R14: This TPL draft includes Requirements R9 to R14 that impose obligations on the PC/TP that differ from the way planning models are compiled in accordance with the existing MOD standards. Manitoba Hydro comments on R9 to R14, as follows: R9: Agree. R10: The TSP is the Functional Model entity that should provide the Firm Transmission Service data and Interchange Schedules to the PC. R11: Agree R12: Agree R13: We disagree that the Resource planner is responsible for Reactive Power devices. Can the SDT explain what they consider should be included in new technologies? R14: While we agree that the TP can provide the PC data of planned faculties, isn't this data already required to be provided under the MOD standards?
Transmission Agency of Northern California	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
OPUC	Yes	R9. — 14 can be addressed in the MOD standards.
Pacific Gas and Electric Co.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective

Organization	Question 5:	Question 5 Comments:
		tariffs, and should not be included again in the proposed TPL-001-1 Standard.
US Army Corsp of Engineers, Northwestern Division	Yes and No	R12 requires the GO to provide "modeling information" for planned outages and/or changes to the generator owner facilities to the Planning Coordinator for each year of the Transmission planning horizon. You need to be more specific with what type of "modeling information" you are requesting from the GO. The GO may have the model parameters for their equipment but this doesn't mean that they have expertise necessary to model system responses or even run a model simulation. So if you are expecting the GO to perform model simulations for each year of the Transmission planning horizon the GO may not have the expertise necessary to comply. Recommend you clarify what you mean by "modeling information".
Public Service Company of New Mexico	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Puget Sound Energy, Inc.	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	In general, we approve and concur with these requirements. The requirement R9 that the distribution providers submit the expected mix of residential, commercial, and industrial loads is necessary to model the dynamic behavior of loads as required in R 2.4.1. This requirement will better model the dynamic response of loads to voltage changes. In R10, the Transmission Planner provides OASIS type information. The TSP should provide this not the TP. R-13 ? Reactive Power Devices and new technologies belongs under every entity, i.e., Distribution Planners should be included as a provider of reactive power devices as well as Resource Planner and Transmission Planner.
Idaho Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Hydro-Québec TransEnergie (HQT)	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

Organization	Question 5:	Question 5 Comments:
		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. It is also important to note that some Canadian Provinces do not "classify" their load mix using "industrial commercial and residential" designations but their load modeling is sufficient, accurate and granular enough to simulate system response. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Sierra Pacific Power Company / Nevada Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Black Hills Corporation	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Florida Power and Light	No	The requirement that "all projected firm transfers modeled" (appropriate for the load level being studied) currently in the TPL Standards does not appear in the proposed standard. Does the SDT feel that Transmission Planners should have unlimited latitude in deciding which types of power transfers to assume in their reliability studies? R9. is not an appropriate requirement as the distribution provider will in many cases not know the exact mix of load types at each ?transmission node? The meaning of "transmission node" is unclear, is this substation? R11. is unclear as to what is meant by "consideration given to spare equipment strategy." What is the appropriate consideration for compliance? What facilities are required to have a spare equipment strategy for compliance? Maintenance outages and times for all BES equipment are not likely to be scheduled or known throughout the entire planning horizon. Rather than specifying "for each year of the planning horizon" it should be limited to "if specifically known". The Resource Planners identified in R13. should know about future generation additions and retirements as well as expected range DSM capabilities but would not generally know about reactive power devices or new technologies. Reactive power devices or new technologies should be removed from R13.
CenterPoint Energy	No	We believe the SDT should have reflected the views of most commenters in this revised draft. Requirements R9 through R14 are overly prescriptive and do not solve an actual problem. Furthermore, we are concerned about requirement

Organization	Question 5:	Question 5 Comments:
and CPS Energy		"creep" where standards include new requirements appropriately addressed in other standards (in this case, the MOD standards) because a different SDT believes the approved standard is inadequate. To clarify our main premise that the excess, misplaced requirements do not solve an actual problem, we believe one would need an extensive imagination to conjure a scenario where insufficient modeling by transmission planners in the subject matter addressed by requirements R9 through R14 have contributed or are reasonably likely to contribute in any meaningful way to a significant reliability event. In summary, we concur with the majority of commenters from the previous draft that R9 through R14 should be deleted. We also believe R1.1 is hopelessly unrealistic. In fact, we are concerned it is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. We recommend that R1.1 be deleted.
SRP	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Tucson Electric Power Company	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in addition to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
SERC Dynamics Review Subcommittee	No	For R9 the LSE should provide the load forecast instead of the DP. For R9 - R14, It is not clear that the specification of data flow appropriate for both RTO and non-RTO situations because there are significant differences in the role of planning coordinator. For example: 1) Who builds and manages the base cases? Shouldn’t the data be submitted to this entity? 2) According to the definition provided in this standard, the Planning Coordinator is ?The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems.? Additionally, we recommend the TPL SDT write a SAR to get the data related changes into the MOD standards or adding it the issues to be considered by the drafting team in the development plan under project number 2010-04 otherwise it will be difficult to remember to include these items in the revised MOD standards.
Modesto Irrigation District	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the

Organization	Question 5:	Question 5 Comments:
		respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Arkansas Electric Coop. Corp.	No	R9. I disagree with providing the mix of industrial, commercial and residential, especially within a 90 day period. It is difficult enough to be able to develop a forecast must less try to quesstimate the mix of the loads.R9 through R14 -- the timing requirement should be tied to the regions model development schedule and not 90 days. The 90 days is too restrictive and not practical however model data should be updated at least annually.
Midwest ISO	No	Since the Transmission Planner has the primary model building responsibility it makes sense to have them aggregate model building information. Therefore, requirement R9 should have the Distribution Provider providing the Transmission Planner and Planning Coordinator with modeling information for real and reactive load forecast? etc. The data of R10 such as firm TS data may not be known by the Transmission Planner (ofter a TO in the RTOs). Also the language implies that there are more than one BA under a TP, also not a typical arrangement in an RTO/ISO. A hierarchical approach might be more appropriate such that the Distribution Provider, the Transmission Provider, and the Transmission Owner supply the data they control to the Transmission Planner and the Planning Authority so that those entities can build models they need to meet the study requirements of the standard.
Tri-State Generation and Transmission Association, Inc.	Yes	We are pleased the SDT pulled out these Requirements. Does the SDT plan to leave them in the standard as notes until they can be incorporated into other standards where they belong? In R11, the term "long-term" is not clear.
Tri-State G&T	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
AEP	Yes	However, although the responsible entities listed for each individual requirement are correct from a functional model (compliance) perspective, in actual practice the data flow may not (and in many instances does not) follow the paths outlined in this draft. For example, the node loads, scheduled interchanges, generation models, facility additions, etc., are all provided to the Transmission Owner (TO), since it’s the TO that typically builds the planning models for their transmission footprint and then provides those models to the Transmission Planner and Planning Coordinator. Therefore, the Transmission Owner should be added as a recipient of this type of data.
Austin Energy	No	Requirements R9 through R14 should be deleted and re-introduced later as part of a change to MOD standards. R1.1 imposes burdensome documentation requirements which will likely become a disincentive for revising modeling data and

Organization	Question 5:	Question 5 Comments:
		should be deleted.
Lakeland Electric	No	It is sufficient to direct the TP or PC to obtain and include the appropriate data outlined in R9 through R14 in their respective model cases. The proposed addition of R9-R14 just adds more evidential paperwork requirements to the TP or PCs plate.
Southern Company Transmission	No	R9 needs to be clarified that the forecast is based on expected mix of residential, commercial, and industrial loads, but that this mix does not have to be supplied.
Brazos Electric Power Cooperative, Inc.	Yes	R9-R14 do not belong in this Standard. Adding requirements in the wrong location only adds to the confusion by forcing review of more Standards by other less relevant entities and causing additional burden by insuring the requirements match between Standards for the SDT. R1.1 should be deleted. Tracking all those changes (outages, etc?) is unreasonable and will essentially be unenforceable, for if the data is not tracked, how will anyone know it is not tracked?. Requiring large amounts of documentation that provide no additional benefit or causes undo burden will result in fewer studies or effort placed into proper study.
ColumbiaGrid	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Southern California Edison	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	Yes	We would like to add a couple of items for clarification. 1) Planning Coordinators and Transmission Planners should make it clear to LSEs, DPs and GOs as to what extent they model loads, reactive devices, and generators and not just rely on FAC-001, FAC-002 or the entities Facility Connection Requirements document to convey that information. 2) If requirements 9 through 14 are to be removed at a later date, then the SDT should be required to initiate the

Organization	Question 5:	Question 5 Comments:
		appropriate action or SAR before its disbanding to insure this happens.
ERCOT System Planning	No	ERCOT recommends that R1.1 be deleted. ERCOT shares the opinion of some that R1.1 is counter-productive and more likely to degrade reliability than improve it. R1.1 discourages transmission planners from revising inaccurate, speculative, or outdated modeling data by imposing new documentation burdens and compliance liability. Adding additional requirements to document changes to data required in requirements R9 through R14, MOD-010, and MOD-012 could induce an atmosphere of using inaccurate data to eliminate the need to document a needed change. Furthermore, it is believed that all modeling requirements should exist in a Modeling standard not a performance standard.
Duke Energy	Yes	In order to ensure these requirements move to the MOD standards, the TPL SDT is encouraged to write a SAR to get the data related changes into the MOD standards or add it to the issues to be considered by the drafting team in the development plan under project number 2010-04.
Central Maine Power Company	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
New York Independent System Operator	No	With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator."
Alberta Electric System Operator	Yes	While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.

Organization	Question 5:	Question 5 Comments:
FirstEnergy Corp.	No	FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If the R9 through R14 requirements remain, we offer the following comments: R9 - In requirement R9, the DP is to provide nodal load projections and include the expected mix of industrial, commercial, and residential Loads. System planning software can not presently accommodate this level of detail along with other load codes/classifications that may already be in use; i.e. municipal load, rural electric cooperative load, etc. Is the intent to require this information in models built and maintained by industry, i.e. MMWG? R10 - The TP does not have access to Interchange Schedules and resources required to supply Load for each of its Balancing Authority. This information may need to be provided by the Resource Planner or some other appropriate entity.
US Bureau of Reclamation	Yes	Comments: While we agree with separating R1 to form R9 through R14, we believe that R9 (modeling information for real and reactive load forecast data) should be applicable to Load Serving Entities (LSE) instead of (or in additional to) the Distribution Provider. In any case, this type of exchange of load information is already covered in MOD Standard or in the respective tariffs, and should not be included again in the proposed TPL-001-1 Standard.
BPA Transmission Reliability Program	No	Requirements for data gathering and load modeling belong in the MOD Standard and not in TPL-001-1. Requirements for dynamic load models should not be specified at this time, because the models have not been developed yet or approved by the RRO (also see comments regarding R2.4.1 under Item 2, above).

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

Transmission Lines

Organization	Question 5:	Question 5 Comments:
Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load		
Los Angeles Department of Water and Power	Yes	See the comment from WECC
Response: The SDT did not receive any specific comments from WECC.		
National Grid	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. [Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
MidAmerican Energy Company	No	MEC disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial,

Organization	Question 5:	Question 5 Comments:
		and residential loads". In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
MRO NERC Standards Review Subcommittee	No	The MRO disagrees with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We suggest the drafting team submit SARs to make the desired changes in the appropriate MOD standards. However, if these requirements are retained than we suggest the following few changes to R9-R14: In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?" The R9 wording on providing "the expected mix of industrial, commercial, and residential loads" should be dropped as the representative mix is difficult to quantify and verify while the benefit to representing the mix is unproven versus normal regional dynamic load representation practices. Many regions already convert normal steady state powerflow loads to standard mixes of, constant MVA, constant current, and shunt admittances which accounts for dynamic behavior. If the SDT decides not to drop these words, the MRO recommends "the expected mix of industrial, commercial, and residential loads" be changed to "the forecasted mix of industrial, commercial, and residential loads". In R9 through R13 the responsible entities should be giving their information to the Transmission Planner in addition to the Planning Coordinator. In R9, revise the text to: "? load forecast data for at least the coincident peak of each year ?"In R10, revise the text to: "Each Transmission Service Provider shall provide ?" In R11, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages?

Organization	Question 5:	Question 5 Comments:
		meant to be made between the two specified types of outages? In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "? for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
LCRA TSC	No	R-11 states that "Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment." This is typically achieved through outage coordination between the individual Transmission Operators and the System Operator. More clarification may help by defining the difference between planned outages and long-term outages as they are used in R-11. This may be an Operations standard versus a Planning standard requirement.
NERC and Regional Coordination	No	R9 - Reactive load forecasts are not generally provided by distribution provider to the Transmission Planner.R11 - The requirements for providing “long term outages” to the Planning Coordinator is vague. What is a “long term outage” and do I need to plan for it? I think the right answer is only if it is expected to occur over the period that the TP establishes their critical system conditions. SDT should initiate the appropriate SAR prior to disbanding.
American Transmission Company	No	We disagree with the approach of temporary requirements because of the problems that arise due to conflicting or uncoordinated standards (e.g. conflicting requirements between FAC-010-1 and TPL-002-0). We support the approach of developing appropriate MOD standards SARs to make the desired changes. However, if these requirements are retained than we suggest the following few changes to R9-R14.In R9, revise the text to: "? load forecast data for at least the coincident peak of each year In R10, revise the text to: "Each Transmission Service Provider shall provide "In R11, is the text referring to "known planned outages" and "known long term outages" What is the distinction that is meant to be made between the two specified types of outages In R12, revise the text to: "? modeling information for planned facilities changes, known planned outages ?". Also, is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages

Organization	Question 5:	Question 5 Comments:
		In R13, revise the text to: "? for planned facilities changes for each year of the Transmission planning horizon including but not limited to generators, and new technologies ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities. We suggested removing the reference to Reactive Power Devices because these devices would not be owned by Resource Planners. In R14, revise the text to: "for planned facilities changes for each year ?". This wording broadens the meaning from simply "new" facilities to also include any "changes" to existing facilities.
Florida Reliability Coordinating Council, inc	No	R9 through R14 ?R9 through R14 should not be addressed in this TPL Standard. Requirements R9 through R14 should be included in future revisions to the MOD standards. If R9 through R14 remain in the Standard, then the following comments are appropriate: R9 ? Recommend adding ?and season (as defined by the Planning Coordinator)? after ?? load forecast data for each year? .Recommend adding ?(as defined by the Planning Coordinator)? after ?Transmission nodes? to allow the Planning Coordinator to appropriately define the term Transmission node. Recommend deleting ?including the expected mix of industrial, commercial, and residential Loads,? from the requirement since this information is not required by Transmission Planners or the Planning Coordinator. Many distribution providers will not know the mix of load type for a given Transmission node. R11 ?Recommend the removal of ?with consideration given to spare equipment strategy,? from this requirement. We feel that the consideration of spare equipment strategy would be better suited in an operating horizon standard (TOPs) rather than in the TPL standard. The term ?long-term outage? in this requirement is vague and the text ?and long-term outages? should be eliminated. The FERC language in Order 693 P-1725 states ?Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy.? There is no mention of ?long-term outages? in conjunction with spare equipment strategy. R12 ? Recommend rewording as follows: ?Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned generator outages for each year of the Transmission planning horizon, within ninety days of a request for such information." The language ?long-term outages for generation equipment? is vague and unclear as to what is a long-term outage and what specific type of generation equipment should be considered. R13 ? Propose adding ?and any changes to existing plans? after ?new planned facilities? as shown below: ?Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned Facilities and any changes to existing plans for each year of the Transmission planning horizon??
NSTAR Electric	No	1. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load

Organization	Question 5:	Question 5 Comments:
		cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. 2. Add to the last sentence of R9 as follows "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 3. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: "R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 4. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as follows:"R11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 5. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows:"R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." 6. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 to read as follows:"R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] " 7. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). There should be specific contingency descriptions associated with long-term outages.

Organization	Question 5:	Question 5 Comments:
		Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
ISO New England Inc.	No	a. With respect to R9 "including the expected mix of industrial, commercial and residential loads", this provision may be inadequate to be practically useful. The potential issues include the variation in end-use load mix through the daily load cycle, seasonal load composition variations, and the ability to translate these end-uses into reasonable and useful steady-state and dynamic load models. It is important to understand how the information will be used and how much additional detail such as distribution network detail is also required. b. Add to the last sentence of R9 through R14 the following phrase, "within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator." c. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R10 to read as follows: R10. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for Firm Transmission Service data, Interchange Schedules and resources required to supply Load for each of its Balancing Authorities for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. d. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R11 to read as followsR11. Each Transmission Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for Transmission equipment for each year of the Transmission planning horizon with consideration given to spare equipment strategy, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. e. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R12 to read as follows: R12. Each Generator Owner shall provide its respective Planning Coordinator with modeling information for known planned outages and long-term outages for generation equipment for each year of the Transmission planning horizon, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator. f. Flexibility is needed to conform with the requirements of the specific Planning Coordinator. Suggest changing R13 and R14 as follows:R13. Each Resource Planner shall provide its respective Planning Coordinator with the modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to generators, Reactive Power devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.. [Violation Risk Factor: TBD] [Time Horizon: TBD] R14. Each Transmission Planner shall provide its respective Planning Coordinator with modeling information for new planned facilities for each year of the Transmission planning horizon including but not limited to Transmission Lines, circuit breakers, Reactive Power devices, Protection System equipment and control devices, and new technologies, within ninety days of a request for such information or as otherwise described in procedures established by the Planning Coordinator.

Organization	Question 5:	Question 5 Comments:
		[Violation Risk Factor: TBD] [Time Horizon: TBD] g. Planned and long-term outages are two fundamentally different concepts and should be treated separately. Planned and Long-Term outages should be defined. Define how planning events in Tables 1 and 2 are associated with each type of outage (e.g. P4, P5, or P6). Should there be specific contingency descriptions associated with long-term outages? Define length of a "Long Term" outage. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~ Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

Transmission Lines

Generators

Circuit breakers

Reactive Power devices

Protection System equipment

Control devices

New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

Organization	Question 5:	Question 5 Comments:
R1.1.5 Interchange **R1.1.6** Network resources required to supply Load		
Gainesville Regional Utilities	Yes and No	I agree with the approach you are taking concerning this modeling data. I understand that "long term outages" for transmission and generation elements refer to a time frame greater that one year. But I am unclear if the "known planned outage" refers to the same time frame or does it apply to a normal scheduled maintenance type outage of less that one year. Are these "shorter that one year" outages better handled by sensitivity studies since they are normally during an non-peak seasons of the year? Again, the smaller utilities should provide all the requested data to the RRO, but should only have to answer to issues involving their elements discovered at the RRO level.
Response: The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known. **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known		
JEA	Yes and No	R9. JEA does not agree that the Transmission Planners should have the responsibility to perform load development or sanity checks on the DP's forecasted real and reactive loads based upon superfluous information like the customer mix. Also, JEA recommends adding language that gives the Planning Coordinator the option to require the forecast by season. R10. JEA agrees R11. JEA recommends that R11 be split into two functional requirements: (A) the provision of known planned outage information, and (B) the provision of "potential long-term forced outages of transmission equipment where readily available spares are not identified". JEA can support requirement (A), but believes that requirement (B) should be part of an operating horizon standard (TOP?) where the availability of spares and spare equipment strategies can be refined in a responsive manner as the opportunities evolve. JEA does not believe that the industry should overbuild its system for the possibility of a rare "low probability" equipment failure event will occur and no reasonable replacement alternative will exist in the world. R12. Need to define long-term outages R13. JEA agrees R14. JEA agrees
Ameren	No	We consider the proposed requirements R9-R14 to be largely a duplication of the MOD standards and do not agree that they belong in the proposed TPL-001-1. We would propose that a reference to the MOD standards would be more appropriate so as not to create a double-jeopardy compliance situation. If it is determined that the requirements R9-R14

Organization	Question 5:	Question 5 Comments:
		need to stay, the proposed standard needs to reflect the existing data flow processes and consider who builds the models, which is the Transmission Planner, and not the Planning Coordinator. According to the definition provided in this standard, the Planning Coordinator is "The responsible entity that coordinates and integrates transmission facility and service plans, resource plans, and protection systems." In our case, the Transmission Planner receives: a) load forecast (real and reactive) information from the Distribution Planner or Load Serving Entity, b) transmission ratings/impedance/topology(outage) information from the Transmission Owners, c) generation ratings/capabilities/outage information from the Generation Owners, and d) designated network resources (existing and future), as well as external obligations, from Resource Planners. The Transmission Planner develops powerflow and corresponding dynamic models from this information including load magnitude and distribution, generation dispatch, and net scheduled interchange, and provides the models or modeling components to the Reliability Coordinator and Planning Coordinator. Other organizations may have similar problems with data flow processes as specified in R9-R14.We view the R9 requirement of the proposed TPL-001-1 for the Distribution Provider to provide real and reactive load forecast data, including load mix information, to conflict with R1.4 of MOD-013-1 which has the RRO as setting the requirement for the dynamic load data. R10 needs to be modified to reflect the RTO activities related to the coordination and sale of Firm Transmission Service, which is not a Transmission Planning activity.R11 needs to be modified to drop the "spare equipment strategy". This is not a modeling issue and should be covered in standard TOP-002-2 (see R1 and R6).R13 needs to be modified to drop the "Reactive Power devices and new technologies" because Resource Planners typically do not know about these devices. The Transmission Planner or Owner may be the more appropriate entity. We view R14 as an extension of Standards MOD-010-0, MOD-011-0, MOD-012-0, and MOD-013-0.
Exelon Transmission Planning	Yes and No	R11 shouldn't include consideration of a spare equipment strategy. All known planned and long-term outages of transmission equipment should be included regardless of the spare equipment strategy.
IESO	Yes and No	A. R9: Agreed B. R10: Holding the TP to provide modeling information on Firm Transmission Service, (a TSP's role), Interchange Schedules (also a TSP's role), and resources required to supply Load for each of its Balancing Authorities (Resource Planner's role) may not be appropriate. In fact, the TP relies on others to provide this set of information for developing its own study model. We suggest to change the responsible entities to these specific entities; or if the TP is required to provide the PC with the model, then there should be requirements in other standards to obligate these other entities to provide the TP with the needed information. C. R11: The phrase "with consideration given to spare equipment strategy" is vague (not enforceable or measurable) and does not appear to add anything to the required product which should already have the spare strategy and capability taken into account when outage plans are developed. We suggest to remove this phrase. If this was retained, the follow on question is why R12 doesn't have a similar requirement (note that a generator outage may not be due to maintenance of the generator itself; it could be due to outages to step-up transformers, breakers or switches for which spares may be

Organization	Question 5:	Question 5 Comments:
		carried). D. R12: Agreed. E. R13: We are not sure what purpose to include "and new technologies" would serve if such technologies do not result in the provision of generators and/or reactive sources which are already covered. Further, this is vague to determine what constitutes "new technologies" and hence this is not enforceable or measurable. We suggest to remove this term. F. R14: Same comment as in R13 on "new technologies".

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.5 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~ Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

Transmission Lines

Generators

Circuit breakers

Reactive Power devices

Protection System equipment

Control devices

New technologies

R1.1.3 Real and reactive Demand of Load

Organization	Question 5:	Question 5 Comments:
R1.1.4 Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** 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 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 due to the unavailability of the long lead time equipment.		
Progress Energy Florida, Inc.	No	PEF as a general rule believes that Requirements R9-14 can and should be addressed in a MOD Standard. Individual comments on particular ones that PEFs sees as problematic are as follows:R9: This requirement is problematic in its present wording. As worded it would appear to infringe upon the outlined process regarding provision of load forecast data as stipulated in PEFs Attachment K document, mandated to be included as an Attachment to our Tariff per FERC Order 890. In PEF's Attachment K, load forecast data, as submitted by all entities responsible for providing such data for PEF native load, must be submitted by January 1 of each year. Implementation of R9 would thus set in place two binding regulatory processes for a situation in which only one is needed. Furthermore, the requirement uses the term "transmission node", a term which is ambiguous and not easily applicable in the electric utility business. Terms such as "feeders", "substations" or "delivery points" might be more appropriate.R11: PEF appreciates the consideration given with the term "known planned outages", given that specific dates for planned outages in the long-term planning horizon are often difficult to know. This point concludes, however, with the addition of the phrase ?with consideration given to spare equipment strategy?, and PEF does not understand what is meant by this term nor why it is given special consideration in a discussion of planned outages. Spare equipment is just as crucial, if not more so, in the event of an unplanned outage. Furthermore, consideration of spare equipment strategy is already handled as part of PEF's planning processes and as part of the existing TPL Standards. PEF therefore requests that the phrase "with consideration given to spare equipment strategy" be removed from R11.R13: PEF is unsure as to the meaning of "for each year of the Planning horizon". PEF would point out that if from one planning cycle to the next, the modeling of a particular planned generator has not changed, the Resource Planners should not have to re-submit the same data over and over again on an annual basis. Additionally, PEF asserts that its Resource Planners are not involved in the development or implementation of Reactive Power devices or new technologies, and therefore requests that these specifications be removed.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning. The phrase "for each year of the Transmission Planning Horizon" was deleted in the associated requirements. Requirement R1.1.2 now addresses that the models		

Organization	Question 5:	Question 5 Comments:
		shall represent each year of the Near-Term and Long Term Transmission Planning Horizon. The SDT agrees with your comment on the Resource Planner. The standard is no longer applicable to the Resource Planner and the requirement has been deleted. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~ Models for the Planning Assessment shall represent: **R1.1.1** Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** 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 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 due to the unavailability of the long lead time equipment.
Lafayette Utilities	No	In Draft 2 of TPL-001, the SDT has adopted ?Planning Coordinator? as a new defined term. That term is used frequently in the new draft Reliability Standard (including in Requirements R9 - R14 but also, most notably, in Section A.4.1.1). The

Organization	Question 5:	Question 5 Comments:
System		SDT explained in its response to comments on Draft 1 that it had taken the definition of "Planning Coordinator" from the NERC Functional Model. However, the term "Planning Coordinator" is not used in the NERC Registry Criteria, nor does it appear in the NERC Glossary. Because the latter form the basis for allocating compliance responsibilities, the SDT should eliminate use of "Planning Authority" and should adopt in its stead a term that is used in the Registry Criteria (such as "Planning Authority"). With respect to the incorporation of data provided under Reliability Standards MOD-010 and MOD-012 into the studies contemplated by the revised version of TPL-001 (see Requirements R1 and R5), Lafayette urges the SDT to clarify entities? obligations with respect to the provision and use of this data, particularly with respect to Planning Coordinators/Authorities. As presently drafted, MOD-010 and MOD-012 do not apply to Planning Coordinators or Planning Authorities, and these standards also do not provide for these entities to receive MOD-010 and MOD-012 data from the entities that are subject to these two Standards. Further, to the extent that Requirements R1 and R5 require Transmission Planners to use MOD-010 and MOD-012 data, is it contemplated that Transmission Planners will obtain this data from Resource Planners and Transmission/Generation Owners in their areas, or will Transmission Planners merely be obligated to incorporate the data that they themselves provide under MOD-010 and MOD-012 into their studies? Requirement R9 directs each Distribution Provider to furnish its "Planning Coordinator" with modeling information that includes "real and reactive load forecast data" at Transmission nodes" and "the expected mix of industrial, commercial, and residential Loads." As discussed previously with respect to Requirement 2.4.1, Distribution Providers may consider the information required by R9 to be commercially sensitive such that its disclosure could have adverse competitive effects. The information specified in R9 therefore should be protected from disclosure unless the provider of the information authorizes its release or other appropriate protections are in place. Additionally, given that this requirement directs the provision of "load forecast data," it seems more appropriate that the requirement apply to "Load-Serving Entities," "Distribution Providers that serve load" or "Distribution Providers that are also Load-Serving Entities." Requirement R10 assumes that the Transmission Planner has access at all times (and, therefore, is in a position to provide within 90 days of a request) to Firm Transmission Service Data, Interchange Schedules, and resources required to serve load for each of its Balancing Authorities for each year of the transmission planning horizon. The Transmission Planner, however, may only receive such information periodically (e.g., annually or semi-annually) from its Balancing Authorities for use in the planning process. It is more likely that, at any point during the year, the Transmission Owner, Transmission Operator, or Transmission Service Provider would have access to the specified information. Requirement R10 should be expanded to include these other entities, which probably will have access to the data throughout the planning cycle. Requirement R11 does not specify whether outage information provided by a Transmission Owner must be updated (e.g., if the outage schedule changes after being provided upon request by the Planning Coordinator). The Transmission Owner's obligations with respect to providing updated information should be clearly stated. Additionally, it is not clear what the SDT means by the phrase "giving consideration to spare equipment strategy." If the intent is that Transmission Owners shall factor into their outage decisions and timing the availability of spare equipment that might affect the need for or duration of an outage, that intent should be stated in clear terms.

Response: v4 of the Functional Model which has been approved by the BOT includes the term 'Planning Coordinator'. The definition has been deleted from this

Organization	Question 5:	Question 5 Comments:

posting as it has already been implemented in another project.

In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The standard's wording regarding "spare equipment strategy" has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner's "spare equipment strategy" should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

- Transmission Lines
- Generators
- Circuit breakers
- Reactive Power devices
- Protection System equipment
- Control devices
- New technologies

R1.1.3 Real and reactive Demand of Load

R1.1.4 Firm Transmission Service

R1.1.5 Interchange

R1.1.6 Network resources required to supply Load

R2.1.4 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 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 due to the unavailability of the long lead time equipment.

Organization	Question 5:	Question 5 Comments:
E.ON U.S. Transmission Planning	Yes and No	R1 states “Each Transmission Planner and Planning Coordinator shall maintain System models “ and R7 states “Each Transmission Planner and Planning Coordinator shall determine and identify individual and joint responsibilities” but R9-R14 requires that data flow through the Planning Coordinator. Requirements R9-R14 should allow the data to be provided to either, as appropriate for the situation.R9 ?neighboring systems? should be replaced with more descriptive terms such as Planning Coordinators of ? or Transmission Planners of ? R10 The Transmission Planner is a user of this data, just like the Planning Coordinator, and is not the source of this data. The responsibility should be placed on the “source provider” like R9 and R11-R14. R11 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages. R12 The requirement should be limited to planned outages and existing outages that may be long-term due to the spare equipment strategy. The contingency analysis covers all other future outages.

Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

The SDT agrees that the wording regarding modeling of outages is confusing. In response the SDT has eliminated Requirement R11 and included a new Requirement R1.1.1 to require modeling of planned outages of generation and Transmission Facilities when they are specifically known.

The standard’s wording regarding “spare equipment strategy” has also been revised and removed from the modeling requirements. Requirement R2.1.4 now addresses how a Transmission Planner’s “spare equipment strategy” should be considered in Transmission planning.

R1. Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~Models for the Planning Assessment shall represent:

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R1.1.2 New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as

Transmission Lines

Generators

Circuit breakers

Reactive Power devices

Organization	Question 5:	Question 5 Comments:
Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load **R2.1.4** 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 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 due to the unavailability of the long lead time equipment.		
Orlando Utiliites Commission	No	If improvements are needed to the MOD standards then those should be addressed in the MOD standards. This is beyond the scope of the TPL standards. Creating requirements that are not within the scope of a particular standard invites compliances issues and also creates an environment where it may not be possible to comply with both standards. However if you are going to retain these please consider: R7: Revising to state "Each Transmission Planner and their associated Planning Coordinator" otherwise this could be interpreted that every TP & PC has to have an agreement with every other TP and PC in existence on their joint and individual responsibilities. R8: This seems to be redundant with the FERC order 890 requirements for an Attachment K process. That process already has an audit mechanism in FERC and a reporting mechanism in the form of the clients of that process. Having NERC auditors monitor this type of process seems a distraction from their purpose of enhancing system reliability.
Response: In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1.** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R1.1** ~~The Planning Assessment shall include documentation of the technical rationale for modification of any data that was provided in Requirement R9 through R14, MOD-010, and MOD-012.~~ Models for the Planning Assessment shall represent:		

Organization	Question 5:	Question 5 Comments:
R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known. **R1.1.2** New planned Facilities and changes to existing Facilities for each year of the Near-Term and Long-Term Transmission Planning Horizon, such as Transmission Lines Generators Circuit breakers Reactive Power devices Protection System equipment Control devices New technologies **R1.1.3** Real and reactive Demand of Load **R1.1.4** Firm Transmission Service **R1.1.5** Interchange **R1.1.6** Network resources required to supply Load Regarding the comment pertaining to Requirement R7, the SDT believes there is an inherent association between the TP and its PC and it should not be interpreted that every TP needs an agreement with every other TP and PC. Regarding the comment pertaining to Requirement R8, the SDT believes the requirement captures the intent of FERC Order 890.		
BCTC	Yes	We can live with the proposed Requirements, but expect some problems may arise with implementation. For example, to accurately model our system for stability studies, we require models of adjacent systems. It is not clear how we will coordinate this requirement within the WECC base case process.
PacifiCorp	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.
Arizona Public Service Co.	Yes	We agree that the MOD Standards need modifications and additions to be used for Transmission Planning, We also agree with the movement of the R1of the first draft to the R9 through R14 of this draft, We also agree that when the MOD Standards are replaced, then remove these Requirements from the TPL Standard.

Organization	Question 5:	Question 5 Comments:
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
SMUD	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response but the majority of the industry has responded negatively and the SDT has changed the requirements as shown in the summary response. .		

6. The SDT has modified the requirements relating to short circuit analysis Do you concur with the modifications reflected in Requirements R2.3 and R4. If not, please state why and/or suggest specific changes.

Summary Consideration:

The majority of commenters responded negatively. In general, commenters indicated a need for clarifying what specific short-circuit studies were required. While it's an annual requirement, what year or years should be studied? Is there both a short-term and long-term requirement or is it just short-term? In addition, the need for studies beyond those of a "normal system" was also questioned. To provide clarity on these issues, the SDT changed Requirements R2.3 and R2.6.2 and created a new Requirement, R2.7, to address the need for corrective actions specific to when fault interrupting duties are exceeded while also deleting Requirement R4 as those requirements are now included in Requirement R2.3. In addition, some entities suggested these requirements belong in a separate standard such as FAC-002 or a new standard. However, the SAR for this project specified that short-circuit requirements would be included in TPL-001; therefore, the suggestion to move these short-circuit study requirements to a separate standard cannot be implemented. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3.

In response to industry comments, Requirement R4 has been deleted and the following requirements have been changed:

R2.3 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. 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.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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.

R2.7 For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall:

R2.7.1 List System deficiencies and the associated actions needed to achieve required System performance.

R2.7.2 Be reviewed in subsequent annual Planning Assessments as to implementation status.

Organization	Question 6:	Question 6 Comments:
NPCC	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Los Angeles Department of Water and Power	No	Short circuit study is a static study, there is no dynamic involved. The main purpose of short circuit study, from a planning perspective, is to size the breakers to ensure the breakers can interrupt a fault in the system when called upon. R4 requires simulation including contingencies, for what purpose is not known. The language implies there are single contingencies that could result in higher duties. I disagree. The highest duty a circuit breaker will see is when the system is whole and with all generator units in service and the fault to be cleared is a bus fault. Any single contingency that involve losing a unit or any component in the system will result in a weaker system and less short circuit duties. This is elementary. I cannot envision of any single contingency that would put more units on line or switch in additional transmission facilities beyond a full system with all unit already in service. In R2.3, the requirement is to do the study on an annual basis "and" support of past studies. If the intent is to allow past studies to substitute for annual study, the word "and" should be changed to "or". If the intent is to mandate annual study, then the support of past studies is irrelevant since the annual study supersedes past ones. In addition, short circuit study does not need to be performed annually unless there is substantive addition to the system in the form of a generating unit or a major transmission facility. So it make sense to allow past studies in lieu of annual study if there is no substantive addition to the system.
Transmission Agency of Northern California	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
OPUC	Yes and No	What constitutes a ?normal condition? still needs further clarity.
Pacific Gas and Electric Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Public Service Company of New Mexico	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion

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		whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
PacifiCorp	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute ?normal? condition or ?following any single Contingency condition?.
Puget Sound Energy, Inc.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Idaho Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or ?following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
SMUD	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Hydro-Quebec TransEnergie (HQT)	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Sierra Pacific Power Comapny	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit

Organization	Question 6:	Question 6 Comments:
/ Nevada Power Company		studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Black Hills Corporation	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Arizona Public Service Co.	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a three phase fault on a Facility starting from a normal condition, please clarify whether the result would constitute “normal” condition or “following any single Contingency condition”.
Exelon Transmission Planning	No	R2.3 is not clear as to which year’s studies are required. Is the Planning Assessment time frames in R2 also applicable to R4? The phrase 'years one or two of the near-term planning horizon' should be included.
SRP	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Tucson Electric Power Company	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.

Organization	Question 6:	Question 6 Comments:
SERC Dynamics Review Subcommittee	Yes	It is not clear in the standard what is meant by ?single contingency?? Is the concern in Requirement R4 limited to single contingencies that may result in a system state which results in a greater circuit breaker interrupting duty?
Austin Energy	Yes and No	Transmission Planners should assess equipment short-circuit capability under normal conditions, but the need assess its capability following a contingency is so rare it should be left to the planner's selective analysis and not made a specific requirement in the standards.
Modesto Irrigation District	Yes and No	Comments: We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting there reference to the contingencies to be used in the study.
Tri-State Generatino and Transmission Association, Inc.	Yes and No	R2.3 is acceptable as written. R4 is redundant and should be eliminated. Also, the contingency short circuit study requirement does not appear to meet the purpose described in this draft standard (breaker duty monitoring). Three-phase short circuits on an intact system should cover the highest fault conditions, and thus the most critical breaker duty conditions.
Tri-State G&T	Yes and No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition.” Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Lakeland Electric	No	R2.3 or R4 should specify how many and / or how to choose which years of the planning horizon shall be studied. R4 should specify method of choosing which single contingencies to study as larger systems will require an inordinate amount of work to outage every element during each of the study years of the short circuit analysis.
Brazos Electric Power Cooperative, Inc.	No	2.3 is acceptable, the deletion was recommended in our previous comments.R4 should not be added to this Standard. It adds nothing to the document the way it is worded and is quite similar to 2.3.

Organization	Question 6:	Question 6 Comments:
NERC and Regional Coordination	No	Attributes of the short circuit analysis needs to be better define. For example which studies need to be done, for what period and how often.
ColumbiaGrid	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal condition and following any single Contingency condition that would result in greater circuit breaker interrupting duties”. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study. We suggest R4 be modified to read “Short circuit capability of its equipment under plausible system configurations that would result in the greatest circuit breaker interrupting duties”.
Midwest ISO	No	The language throughout the standard is not precise as relates to "studies", "analysis", and "assessments". R2.3 appears to say that the actual simulations upon which the annual assessments are made need not be a current year study. If that is the intent the following wording would be more clear: "Short-circuit assessments shall be conducted annually and may be supported by current or past studies. R4 should be grouped with R2.4. In general the standard seems to meander and elements of the same types of studies are scattered, making it difficult to grasp the study requirements with clarity. Also the language of R4 is unclear as it describes short circuit studies in terms of contingencies. Better language would be "shall assess the short-circuit capability of its equipment under system intact topology and any single facility (or branch) out condition that is expected to result in greater ?".
Southern California Edison	Yes and No	We agree with R2.3. However, R4 requires assessment of “Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute “normal” condition or “following any single Contingency condition”. Also, by specifying the normal and single contingency conditions, R4 is straying into “how” to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Duke Energy	No	It is not clear in R4 what is meant by ?single contingency? and this situation is unlikely to increase fault current. The phrase ?under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting

Organization	Question 6:	Question 6 Comments:
		duties? should be deleted.
Central Maine Power Company	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with, " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
NSTAR Electric	No	1. R2.3 should be changed to indicate the year(s) for short circuit analysis. 2. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". 3. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
New York Independent System Operator	No	In R4, suggest striking, "that would result in greater circuit breaker interrupting duties?".
Alberta Electric System Operator	No	We agree with R2.3. However, R4 requires assessment of ?Short-circuit capability of its equipment under normal conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties?. Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
ISO New England Inc.	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
US Bureau of	No	Comments: We agree with R2.3. However, R4 requires assessment of “Short circuit capability of its equipment under normal

Organization	Question 6:	Question 6 Comments:
Reclamation		conditions and following any single Contingency condition that would result in greater circuit breaker interrupting duties". Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 7 of 12Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute ?normal? condition or ?following any single Contingency condition?. Also, by specifying the normal and single contingency conditions, R4 is straying into ?how? to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
BPA Transmission Reliability Program	Yes and No	We agree with R2.3. However, we recommend removing the reference to single contingency conditions in R4, for the same reasons as described in the WECC comments. See below: "Since short circuit studies are typically performed by applying a fault on a Facility starting from a normal condition, there can be confusion whether the result would constitute "normal" condition or "following any single Contingency condition". Also, by specifying the normal and single contingency conditions, R4 is straying into "how" to perform a study, which is not necessary in a standard. We suggest deleting the reference to the contingencies to be used in the study.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** 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. 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.		
City Water, Light & Power - Springfield, Illinois	Yes and No	For R2.4 stability studies should not be required annually but should only be required if there is a significant change to the system or system stability was marginal as shown in previous studies.
Response: This question is related to short circuit, Requirement R2.3, not Requirement R2.4, Stability. However, if past studies are applicable, it is not necessary to rerun Stability studies more often than once every 5 years. Your examples are good examples of when a Stability study may need to be rerun more often than once every 5 years.		
BCTC	Yes	R.3 and R4 are acceptable, although we note the R4 gets into details of how to do short circuit analysis which is unnecessary for this standard. In some cases it may be necessary to consider multiple contingencies. Should R2.6.2 say "the SYSTEM shall not include material changes?"?
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. 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. The SDT has changed Requirement R2.6.2 (now R2.5.2) to provide clarification. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:		
Manitoba Hydro	No	R4: The wording for the assessment should be changed from "shall assess the short circuit ability of its equipment" to "shall assess whether bus short circuit levels are within the capability of its equipment". The short circuit assessment should only be required if changes to system topology or generation occur. While short circuit levels are critical for system equipment specifications, ten year planning horizon models are generally not adequate for this purpose as ultimate system fault levels are required. The SDT should clarify the modelling details required for the short circuit assessment and the deliverable of the short circuit assessment. The standard doesn't stipulate if an existing NERC model will need to be modified to include the sequence data and thus allow for three phase and SLG fault analysis or if the planner is to use our "in house" models and just report the results. Typically, short circuit models used for fault studies are not load or season specific, and the simulation is conducted using a flat-analysis (load ignored and voltage at 1.0 pu). Typically, all elements are in service to ensure maximum fault contribution. Can the SDT provide details on what cases have to be assessed ? Year One, each of the first five year, etc. What is the generation dispatch that should be considered? For purposes of equipment rating, a dispatch considering all available generation may need to be considered. Manitoba Hydro requests the SDT to provide some specifics on the need for doing intact and n-1 fault analysis. We think the requirement to consider single contingency conditions is getting into the details of bus modeling to maximize the fault level. If so this seems to be getting into short circuit study methodology and is too prescriptive and unnecessary. To explain this comment, we include a summary of the process used at Manitoba Hydro as follows: Manitoba Hydro follows a two step procedure when studying breaker capability of our system:1. Breaker Rating vs. Bus Fault - Breakers are required to accommodate the entire bus maximum symmetrical fault current at nominal bus voltage with no consideration given to what the circuit breaker may actually be required to interrupt due to its location in the ring. Stations with fault levels above 95% of rated breaker interrupting capability are flagged for further study. This type of analysis will accurately rule out a high percentage of breakers whose capability is adequate. If an appropriate model is available, this step could take up to three person-months for the Manitoba Hydro system. 2. Detailed Examination of Breaker Duty and Location - By considering faults on both the equipment and bus side of the breaker the exact fault current that the breaker must interrupt can be determined. In a ring bus arrangement the breaker in question is assumed the last breaker to clear the fault. In addition, factors such as X/R ratio & operating voltage are also taken into account. To provide a safety margin to account for modeling tolerances we recommend a circuit breaker for replacement when the fault value is greater then 95% of the breaker rating. Other companies may use different breaker replacement threshold levels. This detailed analysis could require up to one person-month, depending on the size of the station, for each detailed assessment. The standard should specify what is to be reported as a result of the short circuit study. Should the report include:? Documentation of the criteria used for the study? A

Organization	Question 6:	Question 6 Comments:
		listing of the SLG and three phase fault levels compared to the lowest breaker capability at a bus. ? Documentation of more detailed analysis of for breakers whose capability is within threshold of the station fault level.? A listing of the breakers to be replaced. Alternatively, should the standard just require the planner have a separate report on the fault analysis that can be provided on request.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. 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. The SDT has chosen not to prescribe all conditions but expects that studies would assume all equipment in service, which could impact the study area, to calculate maximum potential fault currents.		
National Grid	No	a. R2.3 should be changed to indicate the year(s) for short circuit analysis. b. In R4, suggest replacing, " and following any single Contingency condition that would result in greater circuit breaker interrupting duties" with , " giving due consideration to the potential sequence of equipment operation". c. It should be stated in the standard that assumptions should be based on procedures provided by each Transmission Planner and by the Planning Coordinator.
Response: (a) & (b): Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** 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. 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. (c) Procedures used to meet short-circuit requirements of Requirement R2.3 should be included in Requirement R2.7.1 mandated Corrective Action Plans.		
Gainesville Regional Utilities	Yes and No	With a small system like ours, I would like to see a provision where if you do not have any changes in our local portion of the BES, then the previous studies would support my assessment.
Response: This is addressed in the revised Requirement R2.6.2 (now R2.5.2). **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:		

Organization	Question 6:	Question 6 Comments:
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.		
JEA	Yes and No	JEA can agree to this requirement; however, JEA would like to see it addressed in FAC-002 to maintain consistency with the FAC standard requirements.
Response: FAC-002 references the TPL standards to ensure that a short-circuit study is run for new Facilities. The SDT believes that the consistency will continue to exist. The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Progress Energy Florida, Inc.	No	PEF disagrees with, and recommends removal of both R2.3 and R4 on the following grounds:R2.3: Evidence that short circuit analysis has been performed is already mandated through Requirement R1.4 NERC Standard FAC-002-0. Inclusion of the mandate in the TPL Standard is redundant.R4: While the fundamental inadequacy of the short circuit issue is its inclusion in the TPL Standard to begin with (see R2.3 comments), PEF is perplexed at the proposed requirement to perform short circuit analysis for single contingencies. PEF cannot conceive of a scenario for which a single contingency scenario would result in increased fault duty. Such a mindset essentially considers short circuit analysis as equivalent to load flow analysis, which it clearly is not. Short circuit analysis is performed to adequately set relays, size equipment and prevent equipment damage, and as such is not appropriate for inclusion in a TPL Standard.
Florida Power and Light	No	R4. Why is short circuit analysis required for single contingencies? Removing equipment through contingency outages lowers available short circuit duty. Short circuit analysis is not a parallel version of load flow analysis. Evidence that short circuit studies have been performed is currently required in the existing FAC-002-0 Standard. Since the primary concern is the appropriate sizing of equipment and the prevention of equipment damage as opposed to overall grid reliability, we do not see the need for a set of requirements within the proposed TPL standard for short circuit studies.
Florida Reliability Coordinating Council, inc	No	Recommend for the removal of both R2.3 and R2.4. Short Circuit analysis should be addressed in FAC-002 by revising the standard to include additional detail within FAC-002. Another option would be to develop a new standard addressing short circuit studies and requirements.
Response: FAC-002 requires coordination for new Facilities but points back to the TPL standards for requirements that must be coordinated. The SDT believes short-circuit requirements belong in TPL-001-1 and the SAR for TPL-001-1 specified that short-circuit studies were to be included in requirements. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Lafayette Utilities System	No	Lafayette has identified two issues with respect to the Short Circuit Analysis required in TPL-001. First, Requirements R2.3 and R4 do not describe the required Short Circuit Analyses in sufficient detail to ensure that these studies are performed using topology assumptions that are consistent with the assumptions used in the Steady-State and Stability Studies. If inconsistent topology assumptions are used, the results of the analyses would not present a clear and consistent picture for planning purposes. Second, interconnection studies performed under the FERC LGIP procedures typically include considerable short-circuit analysis of the interconnecting transmission system. Entities required to perform an annual Planning Assessment should be permitted to use, for TPL-001 compliance purposes, any up-to-date short-circuit analyses that may have been conducted for an LGIP interconnection study. Forcing these entities to re-perform the analyses for TPL-001 compliance would impose unnecessary cost.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. 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. Please note that this requirement allows for the utilization of past studies.		
Ameren	No	Requirement R4 should be modified to remove the Planning Coordinator such that the "Transmission Planner shall assess the short-circuit capability of its equipment considering maximum interrupting duty for normal or single element outage conditions".
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator.		
CenterPoint Energy and CPS Energy	No	We believe R4 is unnecessary and, judging from industry comments to the previous draft, likely to cause confusion among auditors and planners alike. Furthermore, we believe R4 does not address an actual problem. We are not aware of situations where equipment has been under-rated from the standpoint of short circuit ratings. We recommend that R4 be deleted.
Response: The SDT does not believe that the concepts of Requirement R4 should be eliminated as without them, there would be a requirement for short-circuit studies with no specific result expected. However, Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
MidAmerican Energy Company	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, MEC asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? MEC recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** 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. 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.		
MRO NERC Standards Review Subcommittee	No	a. Since the TPL contingency requirements already require bus fault, stuck breaker, and breaker failure contingencies, the MRO asks the SDT to clarify the purpose of the short circuit study requirements. The benefit to additional short-circuit studies is minimal since analyses already ensure that the system can withstand bus faults and breaker failures. b. The SDT should clarify what single contingencies are to be studied for short circuit studies in R2.4. Is it single contingency as defined in Table 1? Or is it a broader or narrower definition? The MRO recommends that since this is a new requirement, that TPL-001-1 be limited to raise the bar only to involve the single contingencies identified in P1. Failure to do so will require a great deal of additional modeling work in short-circuit studies if single contingencies in P2 are to be included in these studies with minimal benefit. c. The MRO suggests added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? R4 - Clarify that the "short-circuit capability of its equipment under normal conditions" (P0) refers to interruptible rating for breakers only.
Response: (a) These requirements apply to steady state (load flow) and Stability analysis but they do not specifically address short-circuit requirements. The		

Organization	Question 6:	Question 6 Comments:
performance requirements in Requirement R2.3 are specific to short-circuit studies. (b) Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. Also, the need for, or applicability, of 'single Contingencies' in Requirement R4 was dropped when Requirement R4 was merged into Requirement R2.3. **R2.3** 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. 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. (c) The SDT believes that the concerns raised here are covered in the revised requirement R2.3.		
Arkansas Electric Coop. Corp.	No	R2.3.1 should not be deleted. While system wide short circuit analysis should be done annually, there are situations where changes in the BES do impact the short circuit. If these changes result in new equipment needing to be ordered then this needs to be know as soon as possible in order to prevent exceeding equipment ratings or delays because of lead times on equipment.
Response: Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. 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. The SDT has added Requirement R2.7 to provide a Corrective Action Plan. **R2.7** For short circuit analysis, if the short circuit current interruption duty on fault interrupting devices determined in Requirement R2.3 exceeds their Equipment Rating, the Planning Assessment shall include a Corrective Action Plan to address the Equipment Rating violations. The Corrective Action Plan shall: **R2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. **R2.7.2** Be reviewed in subsequent annual Planning Assessments as to implementation status.		
ERCOT System Planning	No	ERCOT believes R4 is unnecessary and does not address an actual problem; ERCOT recommends that R4 be deleted. ERCOT does not presently possess the capability or have access to the data needed to perform the calculations required by R4 as this requirement should apply to only the equipment owner (GO or TO).
Response: The Planning Coordinator is the appropriate entity in some areas. In those areas where this is not the case, the Planning Coordinator may defer to the Transmission Planner's studies. This is a joint responsibility between the Transmission Planner and Planning Coordinator. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term Transmission Planning Horizon and can		

Organization	Question 6:	Question 6 Comments:
be supported by current or past studies. 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.		
American Transmission Company	No	We suggest added clarification of the following questions: 1. Should analysis be performed for the near-term and long-term planning horizon? 2. Should only the peak system condition be analyzed? 3. What does the analysis include (e.g. breaker over duty evaluation and protective relay coordination)? 4. Does the analysis of single contingency for greater duties refer to only the P1 category or both the P1 and P2 categories?R4 - Does the equipment capability reference include the ground grid and bus structures?
Response: The SDT did not add references to equipment beyond interrupting equipment. Circuit breaker or interrupting device ratings should already include support equipment. Lines are rated by the most limiting element and interrupting equipment ratings should also be rated by the most limiting equipment. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. 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.		
FirstEnergy Corp.	No	We do not feel that it is necessary to annually update the short circuit analysis. We suggest the SDT consider increasing this timeframe. In addition, short circuit analysis should be reviewed in areas where transmission or generation changes are planned. Lastly, we feel it would be beneficial for the standard to provide examples of contingencies that could increase fault duties.
Response: An annual "assessment" must be made, but this doesn't necessarily mean a new study unless topology changes accordingly. The SDT has revised Requirement R2.6.2 (now R2.5.2) which allows for the use of past studies. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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 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. Requirement R4 has been deleted and those requirements have been merged into Requirement R2.3 to reflect the expected short circuit model. **R2.3** 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. The analysis shall determine the maximum short circuit interruption duty on fault interrupting devices using the System		

Organization	Question 6:	Question 6 Comments:
short circuit model with any generation and Transmission Facilities in service which could impact the study area.		
Orlando Utiliites Commission	Yes and No	OUC agrees with other commentors that if there is a need for monitoring this, it should perhaps be in a different standard.
Response: The SAR for TPL-001-1 specified that short-circuit studies were to be included in the requirements.		
Dominion - Electric Transmission Planning	Yes	
TVA System Planning	Yes	
Progress Energy Carolinas	Yes	
Platte River Power Authority	Yes	
Tenaska, Inc.	Yes	
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
IESO	Yes	

Organization	Question 6:	Question 6 Comments:
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	
Oncor Electric Delivery	Yes	NA
Entergy Services, Inc.	Yes	
Response: Thank you for your response.		

7. The SDT has reformatted the Steady State and Stability Performance Tables. Do you concur with the modified format? If not, please state why and/or suggest specific changes.

Summary Consideration:

In responding to the reformatted performance tables, industry stakeholders had several comments related to the format changes and also took an opportunity to provide feedback on the table content as well. A summary of the more common industry responses is provided below along with the SDT's reply to each.

FORMAT COMMENTS:

1. The most common input received from industry related to the format of the tables was a desire for the SDT to consider a single table design covering both steady-state and stability. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table design.

2. Many commenters felt the two table design was unduly long covering 13 pages compared to the two (2) pages used for the existing FERC approved TPL standards. Based on the redesigned single format table, the SDT has condensed the information to only 3 pages in the proposed Draft 3 version.

3. Another format change requested was to repeat the header row of column headings on each page. The SDT agrees and has made this change.

4. A few commenters correctly pointed out confusion between the introductory notes and the footnotes which both used numeric references. The SDT corrected this problem by using alpha character references for the introductory notes. The references within the table now clearly point to the footnotes and follow a more logical numerical order.

5. Several stakeholders suggested a Planning Event category naming convention for Planning Steady-State as (P1, P2, P3, …) and Stability as (S1, S2, S3, …) for the two table design. The SDT did not make this change based on a redesign to a single performance table. The team has retained the P1 through P7 references for Planning Events.

CONTENT COMMENTS:

1. The SDT agrees with a number of stakeholders that expressed an opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions, not just those limited to HVDC. The SDT recognizes that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title “Interruption of Firm Transmission Service Allowed” that corrects the problem identified.

2. Some commenters questioned the distinction in performance requirements for the above 300 kV systems. The SDT believes the Draft 2 changes are responsive to the prior industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The team has now included a slightly modified version of stated performance requirements in Draft 3. The SDT has clarified that interruption of Firm Transmission Service is warranted for some Contingencies. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm Transmission service is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

3. 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.

4. Some commenters were confused by Planning Event P2.1 and the SDT has added footnote 8 to better clarify the intent of the P2.1 Contingency review.

5. Many stakeholders correctly noted that Extreme Event item 1 excluded the reference to shunt device. This has been corrected and now includes shunt devices.

6. Some commenters questioned the order of the Planning Events and questioned if they were based on a high to low probability order. The SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency

(P1 and P2), and multiple Contingency (P3 through P7). While the SDT agrees there is some overlap in probability order, for example, between P2 and P3, the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.

7. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. 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 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. As an alternative, an entity could seek an entity variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

The following changes have been made to the standard based on industry comments:

Requirements:

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.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

Table 1 Header Notes

e. For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

h. Planning Event P0 is applicable to steady state only.

Table 1 - Extreme Events – Steady State:

1. Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

Table 1 Footnotes:

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

3. 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 fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

8. Inadvertent tripping of breakers 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.

10. 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 be considered.

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. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode. ~~Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

Organization	Question 7:	Question 7 Comments:
Dominion - Electric Transmission Planning	Yes and No	(1) Dominion - Electric Transmission is okay with the format changes, but suggests that consideration be given to changing the category naming convention for Stability Performance Table 2 to S1, S2, etc. rather than P1, P2, etc. for clarity and to distinguish them from Steady State Performance Table 1.(2) The tables could be improved if the headings were put on each separate page.

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This change has negated the need for the Planning

Organization	Question 7:	Question 7 Comments:
Event category naming convention changes suggested by the commenter and the SDT retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
NPCC	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system, which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
Response: The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service Interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1). The SDT has chosen to leave the information within a footnote and		

Organization	Question 7:	Question 7 Comments:
did not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. 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 the 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.		
TVA System Planning	Yes	TVA believes that the new table format does make the tables much easier to follow. However, the tables can be a little hard to follow for those categories that have both over and under 300-kV categories. Also having header pages at the top of each page of the tables would also help. Should P6 and P7 events be moved to Extreme Events since firm transmission and non-consequential load can be dropped for these events? Seems like these events are very similar to the Extreme Events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT has elected to retain both P6 (N-1-1) and P7 (Common Tower N-2) Planning Events in this third draft. There was no compelling industry opinion for the change and the events were considered by the SDT to be credible events and warrant the Planning Event level of scrutiny. There are more severe versions of these events contained with the Extreme Event area.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Place the titles on each page and put the borders back in.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT believes the new table will also address your concern regarding the borders. If not, please provide a more specific comment in your review of the Draft		

Organization	Question 7:	Question 7 Comments:
3 standard.		
Progress Energy Carolinas	Yes	The readability of the tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability greatly improves and clarifies the requirements of the standard. Additionally, we would prefer that dynamic planning events use labeling such as D1, D2, etc. instead of P1, P2, etc. to differentiate them from steady state events.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The move to a single table was based on a significant number of comments and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Platte River Power Authority	Yes and No	I like the emphasis on stability performance but I prefer one table combining steady-state and stability Categories since the Planning Events are common to both. Divide notes, Evaluation Requirements, and Extreme Events Descriptions into two sub-tables.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of commenters, like yourself, who felt a single table would suffice. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT divided the top notes between those that are applicable to Steady-state, Stability or both as suggested by the commenter.		
BCTC	No	The differences in the tables requiring two tables are not apparent. Furthermore, we have become familiar with working with the current Table 1. Changing to these new tables will result in transition costs. We see no problems with continuing to use the current Table 1 and would prefer to retain it.
Response: While the new tables and naming conventions will require some effort for industry adaption, the SDT believes the tables provide greater clarity and drive the reliability improvements desired by FERC Order 693.		

Organization	Question 7:	Question 7 Comments:
Manitoba Hydro	No	There appears to be little difference between Table I and II other than the performance requirements at the start of each table, which should be embedded within standard. Manitoba Hydro would prefer one table as we believe it serves to simplify the standard readability. Additional Comments on Table 1:The Performance Requirements (Items 1 to 6) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to F to avoid confusion with the Notes at the end of the Table. Item 6 is not applicable for steady state analysis. Suggest changing "Notes" to "Table I Notes" for improved readability if more than one table is retained. Planning Events: In cases where Non-consequential Load Loss is allowed, has the SDT discussed limiting the amount of load lost? Planning Events: For the multiple contingency events, in cases where Interruption of Firm Transmission Service or Non-Consequential Load Loss is allowed, the SDT should clarify that such loss is only allowed after the second event. P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed for AC transmission lines, as in many cases, the firm transmission service is dependent on the outaged AC transmission line or transformer, that is, the contract path. P2-1: Suggest changing :single ended line: to "open ended line". P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer - the contract path. Planning Events >300 kV: Interruption of firm transfer should be allowed if AC contract path is lost due to an event. In many cases the majority of the firm transfer is carried by the contract path ac line, not that unlike the case of the DC line. MH has sold Firm Transmission Service, the delivery of which is dependent on the single circuit Winnipeg-Twin Cities 500 kV line being in-service, This Firm Transmission Service is available in the order of 99.6% of the time. Assuming two 5 day planned maintenance outages per year the availability is 97.3% per year. MH's transmission customers did not want to pay some $800 million in capital costs for a second 500 kV line to increase the Firm Transmission Service availability by 2%, especially considering that Firm Transmission Service loss does not result in loss of load, but results in a call for redispatch (call for Operating Reserves being carried to cover for loss of the largest generator or largest loaded transmission line with associated fast generation runback (SPS)). The inability to interrupt Firm Transmission Service will drive expensive new line construction, or require withdrawal of 1500 MW of firm transmission service from the market. P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. The low probability of P4 events does not warrant the cost of raising the reliability performance requirements.

Organization	Question 7:	Question 7 Comments:
		P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. NERC defines a Protection System as "Protective relays, associated communication systems, voltage and current sensing devices, station batteries and DC control circuitry. In many cases, the protective relays, associated communication circuits and DC control circuits consist of two separate or redundant systems, but the voltage and current devices and station battery may be common. Is the SDT considering a current sensing device, or the station battery, for example, to be a single point of failure? Table 1 Note 4: Imposes a requirement on FACTS devices, and therefore should be elevated to the Requirements in the standard body. Also FACTs devices can be put in a series connection as well as shunt. Perhaps some additional clarification is required. Additional Comments on Table 2: Stability Performance Requirements: ?The Performance Requirements (Items 1 to 5) should have a heading "Evaluation Requirements". These evaluation requirements should be included in the standard body. Also they should be labeled A to E to avoid confusion with the Notes at the end of the Table 2 – Item 4: should the simulation also include the effect of reclosing where applicable? Planning Events: Same as comments on Table 1 regarding treatment of Firm Transmission Service and Non-Consequential Load Loss for >300 kV P4: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P5: Greater than 300 kV - Interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. Multiple Contingency events (P3, P6): Does the SDT envision these multiple events being simulated as a stability run for the second event using a base case with an adjusted system - considering the first event is typically P1 which has been previously run as a separate simulation, typically a P1 event? P5: see Table 1 comment re what is considered a single point of failure. Extreme Events: Evaluation Requirement 1 - R5.5.4 should be R5.4.4 Extreme Event Description 2H: A 3 phase bus fault on a switching station would not normally result in loss of a voltage level and transformers at a station. The event should just be loss of one voltage level plus transformers in a substation. Table 2 Notes: Suggest changing "Notes" to "Table 2 Notes" if more than one table is retained. Note 5 a. Stipulates requirements for generating unit performance - should not be buried in the notes. Also, what is the SDT rationale for allowing units to pull out of synchronism for single contingency events like P2, or P5 - stuck breaker, or P7 - common tower, which is a normal clearing event.

Organization	Question 7:	Question 7 Comments:
		P1: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. P3: Similar to DC lines, interruption of Firm Transmission Service should be allowed if transfer is dependent on the outaged AC transmission line or transformer. It is important for a probabilistic measure of likelihood to be considered in designing Table 1 and Table 2. The various categories of contingencies, P1 to P7, for example, should be ideally arranged in order of magnitude of likelihood, so that the acceptable consequences or the performance requirements may be in an increasing level of severity. However, there are events with intrinsically different probabilities currently classified within each of these contingency categories. For example, in P3 (following loss of a generator followed by system adjustments), another generator forced outage is more likely than a transformer forced outage. In P2 (single contingency), loss of a bus section is less likely than the P3 event of a double generator contingency. Therefore, these P categories, as currently defined, overlap one another in the scale of likelihood. As a result of it, Table 1 and Table 2 have allowed for certain rarer events (e.g., included in single-contingency P2 and double-contingency P3 categories) to incur some significant consequences with unspecified limits, e.g., interruption of firm transmission services or "non-consequential" load loss. It may be better to follow the NERC Reliability Concepts White Paper's approach of displaying these tables in categories of event likelihood, so that the acceptable consequences would be in an increasing level of severity. This approach would then be consistent with Probabilistic Risk Assessment, when the industry has collected enough transmission outage data to enable such a method be applied. Though the US power industry does not have transmission outage statistics collected and analyzed across the industry, Canadian utilities do have excellent data. It seems to be possible for the various contingency events in the current Tables 1 and 2 to be recategorized according to five or six groups of "order of magnitude of likelihood", e.g., M0, M1, M2, M3, M4 and M5. Each order of magnitude of likelihood is ten times less likely than the preceding order. For example, the first order (M1) would be for outage probabilities greater than 1%. The second order (M2) would be for outage probabilities between 0.1% and 1%. The third order (M3) would be between 0.01% and 0.1%, etc. Multiple independent contingencies could be classified based on the product of their individual probabilities, e.g., a generator outage is of order M1, and a transmission circuit outage is of order M2. Therefore, a double contingency of a generator and a transmission circuit is of order M3, but a double generator contingency is of order M2. Having placed the initiating contingencies in these orders of likelihood, it is then feasible for the industry stakeholders to try to agree on the level of acceptable consequences for these magnitude orders of likelihood. In the current draft of this standard, there is no quantified variable degree of acceptable consequences, as envisioned in the NERC Reliability Concept White Paper.There is distinctly different treatment of whether the out-of-service element is below or above 300KV. There is difference in allowing or not allowing firm transaction interruption and/or non-consequential load loss, but neither of them has a specified limit on the MW amounts. With the current layout of Tables 1 and 2, it is not readily apparent that the proposed standard is consistent with a sound risk approach. Having a sound risk approach is very important because investment decisions will be made according to these new, proposed and still-deterministic standards. Planners may find out in their studies that the costs of meeting some unlikely contingencies requiring expensive transmission investments are very high and that these costs are not justifiable based on avoiding those rare consequences. On the other hand, because the amounts of acceptable firm transaction interruption and non-consequential load loss are not specified, the transmission system designed to that

Organization	Question 7:	Question 7 Comments:
		standard with unspecified limits may become vulnerable to cascading events that initiate in the transmission grid below 300 KV. Many entries in the Tables allow non-consequential load losses, but no limits are specified. It raises the question, "If any non-consequential load loss is acceptable, is there a need to study that contingency scenario?" Without a reasonable set of limits, the criteria may not be effective in assuring system reliability. NERC's event analysis group has been using five categories of consequences to classify recent blackouts or major disturbances. A condensed summary of this is as follows. Category 1. Abnormal frequencies > 5min; or inter-area oscillations Cateorgy 2. System separation with no loss of load or generation; or loss of generation (between 1,000 and 2,000 MW in the EI or WI and between 500 MW and 1,000 MW in ERCOT) Category 3. Loss of load (less than 1,000 MW); or loss of generation (> 2,000 MW in the EI or WI and > 500 MW in ERCOT); System separation or islanding with loss of load or generation (less than 1,000 MW). Category 4. System separation or islanding of more than 1,000 MW of load; or loss of load (1,000 to 9,999 MW). Category 5. Loss of load (10,000 MW or more) Lay persons as well as transmission planners can understand and appreciate these ways of defining consequences, e.g., category 5 events mean more than 10,000 MW of load or generation loss. A way to propose reasonable limits to the highly unlikely but potentially severe contingencies, e.g., M3, M4, and M5, would be to limit their designed consequences to Category 2, 3 or 4. A well designed transmission system should limit the consequences of potential cascading outages and their likelihood so that fewer major blackouts would occur, while balancing the cost of investment to the cost of outages to the customers. A number of utilities are already performing PRA studies for their transmission planning. The advantages of using PRA have been demonstrated in the nuclear power industry. It would be desirable to have a pathway for the power industry to transition from the still-deterministic planning criteria in TPL-001 to a probabilistic planning criteria, without having to wait for another major revision to the TPL standard. If the Tables 1 and 2 are arranged and presented consistently with the NERC Reliability Concepts White Paper, the approach will enable that transition to take place naturally. If the TPL-001 standards establish a PRA-compatible Table 1 and Table 2, with contingency categories sorted in order of magnitude of likelihood, and their acceptable consequences also arranged in order of consequences (such as the five categories), the reliability requirement is already seen in the PRA-compatible way of a constant Risk level, Risk = Likelihood x Consequence. When the industry has good data to quantify the probabilities of these various contingencies, the implication of this ?already-accepted? Risk Level would be clear and numerically expressable. What is useful at this time is for the industry to make a forward-looking estimate of what this Risk level would be like, and consider whether it is appropriate and consistent with sound economic and risk principles.

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The top introductory notes have been retained and are now referred to alphabetically to avoid confusion with the referenced footer notes. The top notes also

Organization	Question 7:	Question 7 Comments:

better clarify which are applicable to steady-state, stability or both.

The standard does not place a limit on the amount of Non-Consequential Load loss allowed. However, the maximum Consequential Load loss and its associated Contingency require documentation. See Requirements R2.9 and 2.10.

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.

R2.9 The Planning Assessment shall identify the maximum permissible Non-Consequential Load Loss (megawatt Demand) for those Planning Events where Non-Consequential Load Loss is allowed in Table 1.

In regards to the Planning Event P3, the SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. The SDT believes that interruption of Firm Transmission Service may be justified, so long no firm load loss occurs if the performance requirements do not permit the load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple contingency Planning Events.

In regards to Planning Event P2.1, the reference to "single ended" has been removed and footnote 8 was added to further clarify the event required for study.

Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

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 the 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.

The SDT agrees that FACTS can be series devices and the footnote reference has been modified to better clarify the intent is shunt devices, connected to ground. See footnote 7.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of

Organization	Question 7:	Question 7 Comments:
comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The requirements do not require study of reclosing actions. Only the initial Protection System responses must be simulated. P3 – see above response for Table 1. Based on feedback received the SDT was not compelled to alter its stance on the provision for Non-Consequential Load shed for a P4 and P5 event. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In the multiple Contingency P3 (Gen + 1) and P6 (N-1-1), within a stability study only the 2nd outage is required to be reviewed. The first Contingency is a precondition that needs to be modeled but not evaluated for its Stability response if the P3 or P6 condition is studied for Stability. 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 the 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. In the Extreme Events area of the Stability table the reference to Requirement R5.5.4 has been removed due to a circular reference between the requirements and the table. The Extreme Event item 2h is written consistent with the presently approved TPL D8 and D9 contingencies. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT team agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the		

Organization	Question 7:	Question 7 Comments:
column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter Regarding bottom note 5a, now shown as footnote 1, the SDT believes that no unit should be allowed to pull out of synchronism for more likely single Contingency events such as a three-phase fault on a line, transformer, or generator - a P1 event. The P2 events, even though classified as single Contingency events with normal clearing, are less likely to occur (bus faults, internal breaker faults, etc.). P5 and P7 are multiple Contingency events and are less likely to occur. The SDT believes it is appropriate to allow units to pull out of synchronism for less likely events as long as the other conditions of footnote 1 are maintained. The Planning Events, in general are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, we believe the SDT has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence. The commenter's proposed shift from deterministic planning to probabilistic planning is outside the scope of the SAR for this project. The SDT believes the commenters suggested focus on more detailed probabilistic analysis is better addressed after the industry obtains additional outage data and insight obtained through the TADS effort.		
Los Angeles Department of Water and Power	No	The performance table allows different performance for same contingency at different voltage classes that is arbitrary separated. This is discriminatory and without any scientific or historical basis. There should be only one class for the whole transmission system. Transmission system at below 300kV should not be granted preferential treatment. Mindful also that the initiating causes of last two major continental wide blackouts(one in WECC and the other in the Eastern Interconnections) both started in system at less than 300kV.
Response: The SDT believes it has provided sufficient reasoning why the above 300 kV System should be held to a higher standard. The initial draft of the proposed Transmission planning standard held the planning of 300 kV and higher Transmission Systems to a more stringent requirement than the remaining BES. Although not unanimous, the majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end-use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Additionally, loss of the EHV system stresses the lower voltage parallel paths. EHV transformers can be exposed to long duration outages. Therefore, it was the conclusion of the SDT in Draft 1 to propose greater reliability and operational flexibility through more stringent performance requirements when considering certain N-1 and N-1-1 Contingency events of EHV Systems. Throughout the industry, substation arrangements at EHV levels reflect the importance of these Systems as the designs often consist of the more flexible and reliable ring-bus, breaker-and–a-half or double bus-double breaker protection schemes as compared to the simpler, lower cost single bus arrangements that are commonly found on lower voltage systems. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire		

Organization	Question 7:	Question 7 Comments:
100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.		
Transmission Agency of Northern California	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Public Service Company of New Mexico	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Puget Sound Energy, Inc.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for events could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

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		modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Black Hills Corporation	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.

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Pacific Gas and Electric Co.	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Idaho Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SMUD	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state.

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		Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Sierra Pacific Power Comapny / Nevada Power Company	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believes there should be no distinction between the voltage classes and supports the use of load shed for all cases identified in P4 through P7.
SRP	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tucson Electric	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two

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Power Company		Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.The proposed format covers multiple pages. Add the header rows to each page for easier reading.
Modesto Irrigation District	Yes and No	Comments: We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Tri-State G&T	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate

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		interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
ColumbiaGrid	Yes and No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some maybe some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SGT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Please explain/define the term "single ended line" used in Table 1, P2.1. We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
Alberta Electric System Operator	No	We do not agree with the proposed format changes of the Tables, separating into two Tables is not necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.
US Bureau of Reclamation	No	We do not disagree with the proposed format changes of the Tables. However, we are not sure if separating into two Tables is necessary, or beneficial. It seems like an extra column for event could be added and some changes to the notes would greatly simplify the table. Some of the rows could also be combined; one such example is P2-2 (Loss of Bus Section) and P2-3 (Internal Breaker Fault, non-bus-tie). Will the SDT plan on combining some similar rows? Table 1, P4 and P5 refer to "Faults" as part of the contingency. This is steady state performance and faults are not

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		modeled in steady state. Table 1, P2.1 refers to a "single ended line". Technically, this means we need to generate a "false" bus at each end of the line to evaluate this condition or use a dispatcher power flow which included breaker modeling. Is this an accurate interpretation of the intent of this requirement? We believe there should be no distinction between the voltage classes and support the use of load shed for all cases identified in P4 through P7.

Response: The SDT agrees with the commenter related to the prior two table format and based on feedback received from the Draft 2 standard the SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The SDT believes the commenter will find that the new format is greatly condensed and more user friendly from a readability view.

The commenter is correct that the use of the term "fault" in the P4 and P5 events is not needed from a steady-state view; however, the SDT felt the term is needed to accurately describe the event to be analyzed. From a steady-state perspective, only the resulting condition would be analyzed. Also, with the combined format the term is now better used as the Planning Events also describe the type of fault to be studied within a Stability study. Footnote 3 clarifies that the type of fault is referenced only for the Stability studies.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event.

The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) system. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing system designs. Others agreed with the SDT's approach and indicated that the impact to their systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System.

Based on feedback received the SDT was not compelled to alter its stance on the provision for non-consequential load shed. However, the SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

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National Grid	No	a. In the column "Interruption of Firm Transmission Service Allowed" in both Tables 1 and 2, it is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
Central Maine Power Company	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section.

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		f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?
NSTAR Electric	No	1. Referring to both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column, it is problematic to try to create an "exemption" based on the type of facility such as HVDC. There are situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. 2. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." 3. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. 4. Table 2, Note 5 includes significant clarifications which should not be buried in the back; they are better placed in the definitions section. 5. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Protection System Failure should be defined and noted if the battery system is included.
New York Independent System Operator	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. It is recommended that a note be added stating that the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service, recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note

Organization	Question 7:	Question 7 Comments:
		5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure, such as a battery system which may remove ALL protection at some substations. This Contingency P5 requires all voltages and loadings to remain within criteria, and a stable system response; without interruption of firm transmission service and without Non-Consequential Load Loss, at voltages above 300 kV. Was this an intended outcome of this standard?
ISO New England Inc.	No	a. In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed" column. It is problematic to try to create an "exemption" based on type of facility such as HVDC. There are many other situations in which Firm Transmission Service has been provided, but may need to be curtailed partially or completely following an outage. b. The term 'Firm' may have several different definitions. If 'Firm' Transmission Service or load may be interrupted for exceptional events, then it is conditional and 'Conditional Firm' should be defined. It is recommended that a note be added stating that "the only exception would be for curtailment of conditioned (or Conditional) Firm Transmission Service", recognizing that there may need to be some form of grandfathering in order to avoid having to rewrite transmission service agreements. c. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." d. In Table 1, the "Extreme Event Descriptions" items 3a and 3b should be deleted; they are redundant with Item 1. e. In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. f. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. Assuming that the battery system is included in the Protection System, which it is in NPCC, then ALL protection at substations with single battery systems would be lost. This Contingency P5 requires a stable system response while all bus voltages and loadings to remain within criteria, without interruption of firm transmission service and without Non-Consequential Load Loss, at system voltages above 300 kV. Was this an intended outcome of this standard?

Response:

The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter.

The SDT agrees with the commenter that interruption of Firm Transmission Service may be justified, so long as firm Non-Consequential Load is not interrupted if the performance requirements do not permit the Load shed. See new footnote 10 regarding the SDT stance on interruption of Firm Transmission Service and its use in multiple Contingency Planning Events.

Organization	Question 7:	Question 7 Comments:
The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected. The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft. **Extreme Events - 3b**. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~ The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience to the TPL standard and not include it as a new definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 "Protection System Failure" Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. 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 the 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.		
Tenaska, Inc.	Yes and No	Should add a column to the tables indicated when automatic generation runback/tripping is allowed.
Response: Redispatch of generation is allowed for all Planning Events provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **Header note 'e'**: For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.		
Gainesville Regional Utilities	No	Some of the notes at the top of each table could be considered to apply to some of the events within the table that conflict in part with the standard and with what was stated in the nation wide phone conference. I would also like to see a note in the tables that reflect a technical rationale for the range of elements considered, since some may be impractical and of no technical value for contingencies involving certain facilities especially those on the smaller systems within the interconnected region.
Response: The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. We have attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans.		

Organization	Question 7:	Question 7 Comments:
ITC Holdings: ITC, METC, ITC Midwest	Yes and No	While we like the tables, we don't understand what ?Interruption of Firm Transmission Service Allowed? means in a stability study (as per table 2). How would you interpret that in real-time & study terms? Would you make the stability scenario a limit to selling transmission service? In table 2, should we interpret SLG or 3-phase Fault in P1 and P3 to mean that SLG is the criteria (minimum) but you can run and document the more severe 3 phase faults for compliance purposes? What is the minimum criteria?
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. In some instances, it may be necessary to interrupt Firm Transmission Service in preparation for the studied condition. It could be that from a Stability point of view such action would be beneficial under some conditions. **Footnote 5.** When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – 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 be considered. The SDT has corrected the confusion related to the "SLG or 3-phase" fault reference that the commenter describes in the P1 Planning Event. The table now says 3-phase. We added footnote #3 to clarify the fault types and what study results are sufficient for the case of an SLG fault condition. **3.** 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 fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.		
Hydro-Quebec Transenergie (HQT)	No	In both Table 1 and Table 2, the "Interruption of Firm Transmission Service Allowed", a definition should be provided to clarify that term. That term is more of a Market concept not used by all TOs and defined in their Transmission Tariff. Also, the standard might need to introduce a new term "Consequential Transmission Service Loss" as it does for the Load. Firm Transmission services are generally defined as a service of the same priority as the one for the native load. That does not mean it could not be interrupted. In both Table 1 and Table 2, the "Extreme Event Descriptions" item 1 should add "or shunt device." In Table 1, the "Extreme Event Descriptions" item 3b should be deleted; it is redundant with Item 1.

Organization	Question 7:	Question 7 Comments:
		In Table 2, Note 5 includes significant clarifications and should not be buried in the bottom of the contingency table; Note 5 would be better placed in the definitions section. In Table 1 and Table 2, Contingency P5 requires a fault plus Protection System Failure. The "Protection System Failure" aspect of this contingency brings the necessity to define more clearly what is intended. The notion of needed redundancy or single elements of the protection system, be it physical or electric, has to be addressed to clearly understand the implication of that contingency. Until such clarification is included in this standard or in the future "Redundancy standard", this contingency should not be effective.

Response: The NERC Glossary of Terms presently defines Firm Transmission Service as "The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption." FERC in Order 693 was clear that no planned interruption of Firm Transmission Service should be permitted for single Contingency conditions. We agree that there may be times when Firm Transmission Service should be permitted. The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

5. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – 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 be considered.

The SDT agrees that shunt devices were excluded in Extreme Event item 1 of the Steady-State and Stability tables and the problem has been corrected.

Extreme Event Steady State #1

Loss of a single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service followed by another single generator, Transmission Circuit, DC Line, shunt device, or transformer forced out of service prior to System adjustments.

The SDT agrees with the commenter regarding the opinion that item 3B in the Extreme Event portion of the prior Daft 2 Table 1 Steady-State was redundant and the item has been removed and is no longer referenced in this draft.

Extreme Event – Steady State:

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

The SDT appreciates the input related to the footnote on "System Stable" (new footnote 1) but the SDT chose to keep it as a footnote reference for convenience

Organization	Question 7:	Question 7 Comments:
to the TPL standard and not include it as definition for the NERC Glossary of Terms as suggested by the commenter. Related to the P5 “Protection System Failure” Planning Event the SDT has not deviated from its stance of requiring more stringent performance requirements for the above 300 kV System. 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 the 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.		
Progress Energy Florida, Inc.	No	The Steady State and Stability Tables (Tables 1 and 2), are overly long, confusing, and contain circular references. PEF strongly advises returning to the content and format of Table 1 in the existing TPL Standards, or at the very least, consolidation of the Tables into a single Table. Furthermore, for certain events in Tables 1 and 2, the SDT’s intent concerning the scope of the events and how the events would be simulated in Transmission Planning analyses is not clear. PEF furthermore does not agree with "Interruption of Firm Transmission Service Allowed" and "Non-Consequential Load Loss Allowed" as benchmarks for whether or not a particular BES is reliable (see additional comments in Question 15 on this issue). Tables 1 and 2 at present are 13 pages in total, whereas the existing Table 1, which PEF feels is comprehensive and not in need of revision, is merely 1.5 pages long. PEF understands that the reason behind the length and complexity of Tables 1 and 2 stems from a desire by some to contain all of the primary TPL compliance issues in a tabular format. The end result, however, is not effective and must be made more concise.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The new format more closely mimics the existing TPL table in its readability. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT has attempted to add simplicity as to those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. The change in performance expectations for the above 300 kV System are supported by many in the industry. Please see our response to Q15 for further information.		
Ameren	Yes	The tables could be improved by including the column headings on each page.

Organization	Question 7:	Question 7 Comments:
		Separating the steady-state and stability performance requirements for each planning event helps to provide clarification.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
City of Tallahassee, FL	Yes and No	while this was an improvement, the tables are still confusing and make determination of the compliance requirements difficult. Especially where there are multiple events within a single event category (like P3 or P6) there's confusion about what would be allowed between the two element outages.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – 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 be considered.		
Florida Power and	No	The Table format is extremely confusing and too long.

Organization	Question 7:	Question 7 Comments:
Light		The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated. The tables 1 &2 should be combined and condensed so that they can be read more easily. In their current format, these tables sprawl across 13 pages. The use of footnotes or expanded information in the Table headings is needed to understand the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The changes to the new table have removed the need for repeat headers. Regarding the commenter's statement "The allowed and disallowed actions as well as the applicable time frames for them is not clearly stated." It is assumed that this is in reference to the P6 N-1-1 Planning Event. There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed as long as firm Load, not outaged by the initial event, continues to be served. **Footnote #10** – 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 be considered.		
Exelon Transmission Planning	No	Tables 1 and 2 should be changed such that the header should read 'BES Elements Overloaded' rather than 'BES Elements out of Service' regarding the voltage distinction. The header notes should either not be numbered or numbered with a different scheme to differentiate them from the numbered footnotes to avoid confusion. It is not obvious that all of the footnotes are used in the Tables. The headings should be repeated on each page. Could these tables be made smaller by eliminating some of the unused space such as the large boxes containing a single

Organization	Question 7:	Question 7 Comments:
		'x'?
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The SDT believes the changes improve the readability of the tables. The confusion with regards to the prior "BES Elements Overloaded" has been eliminated in the new table as the prior columns have been deleted. The commenters' suggestion to repeat table headings was a common response from industry, but is no longer a need based on the new table design. The SDT has now utilized alpha character references for the top notes of the table to avoid confusion with the footnotes which are referenced throughout the table. All footnotes are accounted for with the table and are now referenced sequentially for improved readability.		
CenterPoint Energy and CPS Energy	No	We originally believed that eliminating the old Category A, B, C, and D nomenclature would be beneficial. However, looking at the contingency types now being proposed, we are concerned that more confusion has been created. For example, matching applicable facility ratings to Category A, B, and C conditions is reasonably manageable. Matching applicable facility ratings to 7 contingency "buckets" is more confusing, less manageable, and unnecessary. NYISO proposed the concept of analyzing credible multiple contingencies in the operating realm. Most industry opined that NYISO's proposal lacked merit for operating requirements, and we agreed. However, we believe the proposal may have merit for planning requirements. The concept of applying reasonable credibility criteria to multiple contingencies to be studied offers a way to limit multiple contingency analysis to credible scenarios. Less credible (or incredible) scenarios would then fall into the Extreme category. As proposed, the multiple (seven-fold) approach of categorizing contingencies, combined with various sensitivities or alternative scenarios, for multiple years, is unrealistic and unnecessary. We believe creating a separate table for stability performance might be beneficial, but we believe 7 buckets of contingencies is hopelessly unrealistic for stability analyses.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The SDT believes the Planning Events describe the credible Contingencies that warrant more rigorous study and the Extreme Events represent the less credible events that need to be reviewed on a more selective basis by the individual transmission planner. In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of		

Organization	Question 7:	Question 7 Comments:
complexity. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual Transmission Systems. At this time all Planning Events are still within the scope of possible System conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the “more severe” events require Stability analysis as stated in Requirement R4.4. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the “more severe” events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
MidAmerican Energy Company	No	MEC suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) MEC suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc.) The MRO suggests that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
American Transmission Company	No	We think that the tables are so similar that they should be recombined into one. This would require reasonable adaptation of the tables. If the tables are kept separate, then we suggest that the Categories symbols in Table 1 and Table 2 be different to help distinguish between them (e.g. P1:S1, P2:S2, P3.2:S3.2, etc. We suggest that the header text (i.e. Category, Initial System Condition, etc.) be repeated on every applicable page to be

Organization	Question 7:	Question 7 Comments:
		more reader-friendly. The superscripts do not refer clearly to the respective notes. (There are numbered notes in the beginning of the table, numbered items in the extreme events evaluation requirements section, numbered items in extreme event description section, and numbered notes at the end of the table). Perhaps the referenced notes should have unique numerology or format to make the superscript references clearer.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The SDT agrees with the commenter regarding the top notes within the table. We have changed the references to alpha characters to avoid confusion with the footnotes that are referenced with the tables using superscript characters.		
SERC Dynamics Review Subcommittee	Yes	The tables could be improved if the headings were put on each separate page. Separating out the tables for steady state and stability improves and clarifies the requirements of the standard.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.		
Austin Energy	No	Matching facility rating to seven contingency categories is confusing. Furthermore, these seven categories combined with alternative scenarios and sensitivity studies for several years into the future is overly burdensome, unnecessary, and unrealistic.
Response: In regards to matching an applicable Facility Rating to the 7 Planning Event categories, the SDT believes the 7 categories do not add any additional level of complexity. The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to		

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better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has altered its organization of the performance requirements. The need to cover sensitivity analysis is based on a FERC directive from Order 693 and the SDT believes it is a reasonable request which will drive the industry to better understand their individual transmission systems.		
Arkansas Electric Coop. Corp.	No	I disagree with statement #4 for the reasons given in my comments on question 3. Also, if you are going to allow it then consequential generation loss needs to be defined. I also disagree with statement #5. This is a planning standard and as such systems should be planned for planning steady state. Statement #5 should only be allowed if the resulting operator actions are taken into account. A fault on a networked transmission line may open the breakers at each end. Statement #5 stops here when in reality operator actions would isolate the faulted sections and service restored with the transmission line now being operated as two radials. The resulting two radials are what need to meet the performance requirements. Events should be taken to their logical conclusions and the resulting system topology be what meets the performance requirements. The tables need some borders and section dividers. Headers should be on each page. No firm transmission or Non-Consequential Load Loss should be allowed for P2. I think the SDT has it backwards. Non-Consequential Load Loss should never occur and the tables should reflect what is allowed to happen with Consequential Load Loss for each event. Many of the scenarios reflect what should happen with Consequential Load Loss and not Non-Conseqeuntial Load Loss. For example: P2 Bus Section for less than 300 kV -- The load on that bus under this contingency would be Consequential NOT Non-Consequential. For the loss of that bus the load connected to that bus should be ALL the load that is lost, therefore no Non-Consequential Load Loss should occur.
Response: Please see the SDT's response to your question 3 comment regarding your disagreement with statement #4. The SDT concluded from the overall industry comments that a definition for consequential generation loss was not needed and therefore was not added to the standard at this time. The commenter disagrees with statement #5 of the Draft 2 standard which states "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event." However, FERC Order 693 paragraph 1707 references that within the NOPR that preceded the Final Rule "…the Commission believes that the simulations used in planning assessments should faithfully duplicate what will happen in the actual power system and not a generic listing of outages" In paragraph 1716, the Final Rule further clarified that this is the intent of the Commission. Therefore, the wording in the proposed standard. The commenter's disagreement seems to be based on a feeling of needing to plan for no Load drop for single Contingency events; however, in paragraph 1773 it is clear the FERC does allow the loss of Consequential Load. Therefore, Consequential Load Loss that occurs with the initial event is permitted. Serving radial Load tapped from a networked line, from a "singled ended" view or from a single source end (one end of the line open) is covered by Planning Event P2.1 and new footnote 8 should help alleviate the commenter's concerns. Under P2.1 it should be expected that no Load loss would occur. **Footnote 8**: Inadvertent tripping of breakers on one end of a normally networked Transmission circuit such that the line is now open at that end and possibly		

Organization	Question 7:	Question 7 Comments:
serving Load radial from a single source point. The need for headers on each page has been alleviated based on the SDT reformatting of the table to a single table format and greatly condensing the tabular information. The SDT disagrees with the commenter that the SDT “has it backwards” related to the references of Consequential Load Loss and Non-Consequential Load Loss for each event. The performance table accurately depicts when Non-Consequential Load Loss is permitted for various events. Consequential Load Loss is allowed for all events. The table does not try to categorize a type of Load (Consequential or Non-Consequential) that the event is causing to lose electrical service. The initial Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements. In the P2.2 (bus section) event that the commenter references, the difference between the EHV and HV performance requirements is that the Transmission Planner is allowed to drop additional Non-Consequential Load for the HV event.		
Midwest ISO	No	Please add a General Requirements heading before items 1-6 (Steady State) and 1-5 (Stability) which appear to be applicable to all events for each table. The two columns under "BES elements out of Service" could be stricken for simplicity and clarity. If there is a voltage distinction needed, then add it next to the "Yes" or "No" under the "Interuption of Firm Service" or "Loss of Load" columns. Items P0 through P7 are identical in Table 1 - Steady State Performance and Table 2 Stability Performance. The only distinctions are the notes or whether it is an outaged event in Table 1 or a 3 phase/SLG fault in Table 2. Having two tables is redundant and unnecessary, and does not add clarity. It is also recommended that you combine the notes and extreme events from Table 1 - Steady State Performance and Table 2 - Stability Performance into one table. If both tables are to be retained then it is recommended that the SDT take into consideration the following suggestions. With the old Version 0 table, where there was not a separate stability table, it was understood that each of the event types needed to be assessed, but only those that the responsible entity knew were the more severe from a stability perspective needed to have stability analysis performed. By listing events such as single circuit faults (P1) under Table 2, this implies that all events should be simulated with dynamics, though requirement 5.4.1 states events "that would produce more severe System impacts shall be identified,...". The burden to explain why certain events were not selected can be construed now as having to run dynamics on all line faults, or explain why each line was not selected. Most lines embedded within the grid and not near generators or of particular significance to grid dynamic stability need not be studied. We do not believe that the SDT is requiring any additional burden of proof as to why every line in the system is not studied with dynamics, but the standard makes that question more murky than it was before. An overzealous compliance monitor could be confused by the new layout at great expense to the industry. If Table 2 remains, change

Organization	Question 7:	Question 7 Comments:
		Table 2 - Stability Performance to only those events that are important to Stability Analysis. For example the following faults to run would be: 1) Faults near large generators (generator buses, generator lines or transformers near generators)2) Faults with delayed clearing near large generators3) Faults on long or heavily loaded lines with large phase angle differences between terminals. A majority of faults on lines less than 200kV are rarely severe so it is recommended to have the standards reflect this in Table 2 - Stability Performance.
Response: The SDT was persuaded by the commenter and other industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. At this time all Planning Events are still within the scope of possible system conditions that could require a Stability review. The SDT believes the proposed TPL explicitly clarifies that only the "more severe" events require Stability analysis which was implicitly understood within industry for the Version 0 standards as the commenter describes. Many of the conditions described by the commenter could be used as the basis for how a Transmission Planner would select the subset of Planning Events requiring a Stability review.		
Tri-State Generation and Transmission Association, Inc.	Yes and No	It does not seem that there should be different performance limits for DC and AC lines. It is unclear why there is a separation of voltage classes. Perhaps it would be helpful for each TP to specify which voltage levels are considered Bulk on their particular system, then split studies according to that definition. We applaud the SDT's efforts to split contingencies into groups with more-or-less the same system impact. We encourage the SDT that it would be very beneficial to regroup them in order of probability of occurrence, or even better, to group them by order-of-magnitude of occurrence probability. The P categories as now defined seem to overlap in likelihood. For example, in P3 following loss of a generator followed by system adjustments, another generator forced outage is more likely than a transformer forced outage. Loss of a bus section (P2 single contingency) is less likely than the P3 event of a double generator contingency. There is more on the concept of grouping Performance Tables in order of event likelihood in the NERC White Paper, "Reliability Concepts". At the least, notes in the tables - regarding 1) system impact and 2) likelihood of events listed - would be most welcome.
Response: The SDT agrees with the commenter's opinion on the need to allow for all types of conditional Firm Transmission Service interruptions and that the prior Draft 2 version unintentionally provided preferential treatment to HVDC. In the new performance Table 1, a new footnote has been added (see footnote 5) to the column title "Interruption of Firm Transmission Service Allowed" that corrects the problem identified by the commenter. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.		

Organization	Question 7:	Question 7 Comments:
The SDT believes it provided sufficient justification in its Draft 1 response as to why a greater expectation is placed on the above 300 kV (EHV) System. The feedback received from the industry was divided related to the SDT's emphasis placed on a higher expectation for the 300 kV and higher Systems. Some commenters questioned the importance and the high costs that may be needed to mitigate existing System designs. Others agreed with the SDT's approach and indicated that the impact to their Systems would be minimal. Some commenters even questioned why the more stringent approach was not applied to the entire 100 kV and higher Systems. The SDT believes the Draft 2 changes are responsive to industry feedback and reflect an appropriate middle ground related to the importance of the EHV Transmission System. The performance requirements only apply to the Bulk Electric System and the split in voltage provides a subset of the BES. The Planning Events, in general, are ordered based on level of probability. However, the SDT chose to order the table by three main areas: 1) no Contingency (P0), 2) single Contingency (P1, P2) and 3) multiple Contingency (P3 through P7). While the SDT agrees with the commenter that there is some overlap in probability order, for example between P2 and P3, the SDT believes it has more importantly made the proper performance level requirements based on a reliability "risk" level where risk accounts for impact times (x) probability of occurrence.		
AEP	Yes	The formatting is okay. We would like to see the two tables merged. Except in the extreme disturbances sections, Table 1 and Table 2 are nearly identical (the only difference is that fault types are added to Table 2). The tables could easily be merged into one, including the extreme disturbances sections to some extent.
Response: The SDT was persuaded by the commenter and others industry respondents that the two performance tables presented in Draft 2 were redundant in many areas. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance" The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed.		
NB Power Transmission	No	In the past, power systems within the NPCC Region have been designed to meet NPCC design criteria, which is basically that any design contingency does not cause instability of the NPCC defined bulk power system, and does not result in any emergency limit violations (thermal, voltage or stability), unless those violations are contained within a small local area of the system and can be mitigated. Design to NPCC criteria may include, and does include in many cases, interruption or curtailment of firm transmission service, underfrequency load shedding, undervoltage load shedding or SPS tripping of generation and/or load. The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table, which up to this point was acceptable by NPCC design criteria, and the present NERC TPL Standard. The table should not impose new design criteria on the existing power system and should be relaxed such that present NPCC design criteria is acceptable into the future, as historically it has been proven to provide acceptable levels of reliability in the NPCC area. There would be enormous impacts on existing transmission service agreements and compliance issues if the design criteria outlined in the table is imposed. Meeting the design criteria outline in the table would require building new transmission facilities with, in some cases, very little benefit to the

Organization	Question 7:	Question 7 Comments:
		loads in terms of reliability. For example, there is an area of the system consisting predominately load. This area is supplied by two 345 kV transmission lines and three 138 kV lines. Studies show that under certain low probability, but predictable, conditions that the loss of one of the 345 kV supplies will result in unacceptable low voltage or thermal limit violations on equipment within the area. Therefore, an SPS has been utilized which trips load within the area on the loss of the 345 kV line in order to prevent unacceptable low voltage or thermal limit violations under these low probability conditions. In this case these loads are considered non-consequential and tripping them for a loss of a 345 kV line is unacceptable as per P1 in the table. Now assume that this arrangement has been in service operationally for the past 10 years and has only operated twice resulting in a 2 hour outage to these loads each time. Now also assume that these same loads have been interrupted 15 times (for a total of 30 hours) in the past 10 years because outages of a radial line within the area that these loads connected to. In this case, the loads are considered consequential and these interruptions are acceptable. Compliance with the design criteria in the table in this case would require building additional transmission into this area to prevent the load loss by SPS on the loss of the 345 kV line. Assume the cost of this new transmission is 80 million dollars and its net benefit would be to prevent (historically) 2 interruptions out of 17 total interruptions to only the loads in question within the area. The design criteria in the table in this case do not provide adequate benefit for cost for these loads in this area. Adequate transmission planning must take into account engineering judgment concerning cost/benefit ratio to loads as well as type of loads served, expectations of loads in terms of interruptions and where money can be best spent to reduce interruptions to loads. The criteria outlined in the table does not achieve this in all cases. The table should not dictate what contingencies can result in consequential load loss or interruption of firm transmission service. These decisions should be left to local planning engineers who have in-depth knowledge of local transmission issues (as well the interconnected power system)and reliability needs of loads involved. The table should only state that the listed contingencies will not result in system instability or violations of emergency thermal and voltage limits following all automatic actions. Table 1 in the existing version of the TPL Standards with its footnotes b) and C) presently allows for this and does not have criteria as stringent as the new table. The new table should not introduce new, more stringent design criteria.

Response: The NB Power Transmission company has two primary concerns within their response: 1) an inability to interrupt Firm Transmission Service and 2) the inability to shed local Load for what they deem a low probability single Contingency event involving a 345 kV line.

Regarding the Firm Transmission Service concern, the SDT has added footnotes 5 and 10 that should help alleviate the NB Power Transmission company's concerns. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained.

Footnote 5 – When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote 10 – Curtailment of firm transmission service, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, is allowed both as a

Organization	Question 7:	Question 7 Comments:
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 be considered. NB Power expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that they rely on an SPS to drop local area network Load in response to some single Contingency events and that these system designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders (and the SDT) aligned with FERC's 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. As an alternative, an entity could seek an entity variance for the situation described. The process for obtaining an entity variance is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards" The commenter seems to be confused by the term Consequential Load Loss based on the statement "…The proposed table introduces new design criteria for which present power systems within NPCC are not presently designed to - being the restrictions on interruption of firm transmission service and consequential load for certain contingencies as outlined in the table…" The proposed standard places no restrictions on Consequential Load Loss for any of the Planning Events or Extreme Events. The as designed Protection System actions to the event always trip Consequential Load. The performance table merely clarifies if the Transmission Planner can drop any additional Firm Load (Non-Consequential Load Loss) to alleviate the event and meet performance requirements.		
Lakeland Electric	No	Separating steady-state from dynamic (stability) in the tables makes sense. Several suggestions: On page 11 move the planning events note 1 below the Planning Events title or begin note 1 with "For planning events ?" to remove confusion between planning events and extreme event requirements. Include an analysis section in the steady-state and stability requirements sections of TPL-1 that explicitly lays out the performance requirements (including the notes) - this would make the performance requirements very clear on a line item basis and the tables would become a quick reference. Special attention should be given to defined period of time between multiple events and the actions available to the operator. In table 2 (page 17) note 3 should be changed to: "Uncontrolled cascading and islanding ?" in order to be consistent with R5.4.4. " . . . If the evaluation of implementing a change . . . shall be conducted."
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages		

Organization	Question 7:	Question 7 Comments:
that the prior Table 1 and Table 2 encompassed. In the new table format, the top notes were placed under the heading of “Planning Events” as the commenter and other industry participants of suggested. It is not exactly clear what the commenter has in mind related to the “analysis section” described in the response. However, the SDT believes the new table format provides a better “at glance” view of what is needed. However, this does not negate the need to fully understand all requirements within the standard. The time period for allowable System adjustments made to avert performance requirement violations must be completed within the time duration rating and respect the ratings limit. The reference to Requirement R5.4.4 has been deleted.		
Southern Company Transmission	Yes and No	We suggest that the word "requirements" be added to the title of the tables as in Steady State Performance Requirements. We also suggest for header note 2 of Table 2 that the words be changed from "Dynamic voltages shall" to "Voltages during dynamic simulation shall"
Response: The SDT did not include the proposed use of “requirements” in the title of the performance table since they are not within the requirements section of the standard. The SDT agrees with the proposed change in note two of Table 2. The two tables have been consolidated into one table and the header note reference for this item is now note “h”. **Header note ‘h’**: Planning Event P0 is applicable to steady state only.		
Brazos Electric Power Cooperative, Inc.	No	Compared to the new table format, the old Categories were better. Perhaps if there is confusion with the old table or format, this should be cleaned up. We suggest the old tables remain, or combine some of the new sections to reduce the number of categories.
Response: The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency.		
IESO	Yes and No	Condition (5) at the top of Table 1, and Condition (4) at the top of Table 2 are not required since they are already covered by R3.2 and R5.2, respectively. Further, Condition (6) in Table (1) and Condition (5) in Table 2 should be stipulated in R3 and R5 since these are not performance requirements, but rather the analysis (simulation) requirements.

Organization	Question 7:	Question 7 Comments:
Response: The commenter is correct that Condition 5 of the Table 1 and condition 4 of Table 2 which state "Simulate the removal of all elements that Protection Systems and controls are expected to disconnect for each event" is also within the standard's requirement language. However, the SDT has retained this information within the new performance table as it is key information repeated for clarity and convenience. In regards to the comments on condition 6 and condition 5 which refer to "normal clearing", the SDT believes that Requirements R3 and R4 which refer to the need to meet performance requirements stated within Table 1 cover the concern raised. The table note that references "simulate Normal Clearing unless otherwise specified" is now introductory note "d".		
North Carolina Electric Membership Corp	Yes and No	We would like the headings to be repeated at the head of each page. Also, enumerate Stability Tables different from the Steady State to distinguish between them.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". This changed has negated the need for the Planning Event category naming convention changes suggested by the commenter and the team retained the P1 through P7 references for Planning Events. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		
ERCOT System Planning	No	The table is hard to read and follow since it spans multiple pages and the table headers are not repeated on each page. ERCOT believes that there are two many categories. For example, in Table 1 both Category P1 and Category P3 are not necessary. Since they require the same system performance and P3 is more severe than P1, it can be assumed that successful simulation of P3 would result in successful simulation of P1. Category P2-1 can not be simulated without modification to typical transmission models. Normal steady state power flow software typically has as a line either in or out of service, but not half in and half out. "Breaker Fault" and "Stuck Breaker" definitions are included in the table notes, but would probably be better placed with the other defined terms. It is somewhat unclear as to why there are multiple names as the steady state system impact and requirements are the same. Also, the stability impacts would be more severe for a stuck breaker assuming delayed clearing. This would allow for removal of P2-3 and P2-4 in both Tables 1 & 2. It appears that P4 and P5 are duplicating efforts as well. It is not specified which entity is responsible to define and provide contingency definitions in industry standard software format such as those requiring knowledge of protection system failures and lines on the same structure for more than 1 mile. Only entities such as TOs and GOs have access to that knowledge.

Organization	Question 7:	Question 7 Comments:

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

The set of Contingencies considered are not greatly different than those in the currently approved TPL suite of standards. The SDT tried to better clarify those Contingencies that are deemed to be Planning Events, thus requiring corrective action plans, and the Extreme Events which do not require corrective action plans. Most in industry are receptive to the new Contingency categorization so the TPL SDT has not altered its organization of the performance requirements. The P3 and P1 Contingency events are unique and can provide differing results since they result in unique generation dispatch. The SDT believes it is import to study both conditions.

In regards to the P2.1 event, the intent is to capture a potential condition of serving Load that is tapped from a normally networked line from a single source location in the Contingency (single ended) condition. If a line exists (breaker to breaker) that does not directly serve Load, the P2.1 condition would not apply and only the normal N-1 condition of the line would be studied. See the newly added footnote 8 that better describes the intent of the P2.1 Planning Event. The SDT believe existing transmission models will not require adjustment for the P2.1 event, however, Contingency lists run against the model may require some adjustments.

8. Inadvertent tripping of breakers 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.

The stuck breaker reference remains as a footnote to the table – see footnote #11.

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. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode.~~ Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

The commenter is correct that some conditions such as "stuck breaker" or "internal breaker fault" would yield similar outcomes from a steady-state perspective, however, when considered from a dynamic Stability analysis each could have unique outcomes. As the commenter notes a delayed clearing mode, such as the stuck breaker analysis, would be expected to be more severe from a Stability mode. The SDT has retained P2.3 and P2.4 as they are considered single Contingency events as compared to the multiple Contingency stuck breaker event.

The P4 and P5 are unique Planning Events. The P5 Protection System failure can produce various outcomes depending on the Protection System element which failed – relay, CT, PT, battery, etc. The SDT has revised the P5 event description to remove the reference to "single component failure" and has revised the P5 event description to retain what is stated in the currently approved TPL standards under Category C6 through C9 related to the study of Protection System failures. It is left to the judgment of the Transmission Planner and the Planning Coordinator to select the appropriate review and it is expected that a worst case scenario that is something less than loss of the substation, which is considered an Extreme Event, would be evaluated. Finally, as noted in Requirement R3.4,

Organization	Question 7:	Question 7 Comments:
the Transmission Planner and Planning Coordinator is provided flexibility in selecting the more severe P5 events for study related to their system and it is not expected that every possible scenario for Protection System failure would be studied. It most cases it is unlikely that detailed system protection knowledge would be needed to develop the Contingency lists needed to perform Transmission planning studies. Ultimately it is the Transmission Planner and Planning Coordinator responsibility to ensure the simulated Contingencies accurately simulate the removal of all elements that the Protection Systems are expected to disconnect for a given event. If assistance is needed from asset owners then it is the Transmission Planner and/or Planning Coordinator's responsibility to coordinate such a review. The standard does not place requirements on the asset owners.		
Duke Energy	Yes	Separating the steady state and stability tables greatly improves and clarifies the requirements of the standard. The tables could be improved if the headings were put on each separate page. Placing headers in the requirements section of the standard would improve understanding of the flow of the document.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT feels that with the consolidation of requirements that were made for the third posting that headings within the body of the requirements are not needed and NERC legal staff does not support the use of headings to subdivide requirements.		
Florida Reliability Coordinating Council, inc	No	The Steady State and Stability Performance Tables are very long (currently the these two table are 13 pages) and confusing. Please consider combining and condensing the two tables into one, and either add footnotes or expand the table headings to allow better understanding of the performance requirements.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Therefore, the need for repeating headers on subsequent pages has been eliminated as all Planning Events are presented on a single page.		

Organization	Question 7:	Question 7 Comments:
The SDT believes the new table format improves the readability of the expected performance requirements.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Yes	We recommend that the headings be repeated at the head of each page.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
Oncor Electric Delivery	No	In Table 1-Steady State Performance several terms more relating to system stability performance appear such as post-transient voltage, voltage instability, fault plus stuck breaker, etc. These terms would appear to be most appropriate in only Table 2-Stability Performance, where this type of analysis is performed, e.g.- placing a fault at a location based on available short circuit MVA at that point in the transmission system and then analyzing the post transient voltage and generator response.
Response: The SDT agrees that the prior draft Table 1 included some terms that were more appropriate for stability analysis references. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The SDT believes the new table format improves the readability of the expected performance requirements. Additionally, the SDT took great care to separate the introductory table notes for those items that apply to both steady-state and stability analysis as well as independently to one or the other.		
FirstEnergy Corp.	Yes	The overall table format is much improved over Draft 1 and it provides better alignment between the steady-state and stability tables. The SDT is encouraged to consider consolidation into one table based on the minimal differences within the two tables. FE offers the following additional comments related to the tables:TABLE 1, STEADY-STATE & TABLE 2, STABILITY: 1) Do the table notes at the top of the table only apply to the Planning Events? If so, it is suggested to move the row that says Planning Events to be positioned above the notes.

Organization	Question 7:	Question 7 Comments:
		2) Top Table Notes, Item 2 - It is our opinion that it should be based on the TPs criteria. 3) Top Table Notes, Item 3 - These should read consistent on both tables. Also, is cascading well understood and how is it tested for? 4) The use of numeric notes at both the top and bottom of the table causes confusion related to the superscript number references on various terms within the table. The superscript items appear to be footnote references to the notes area at the bottom of the table. It is suggested that the items listed at the top of the table use alpha character references to demarcate each item. 5) Remove the footnote reference to note 3 on the Header titled "Event" (column 3). The reference in column 4 is better suited and covers the intent of the note. 6) For the P3 contingencies, it is unnecessary to individually analyze all BES generation units within a footprint along with an additional contingency. The planner allowed to use reasonable judgment and run only a subset of the larger units in this scenario. For example, there would be no need to contingencies against an outage of each unit at a multi-unit plant. Checking the contingencies against the outage of the largest unit at that plant would be sufficient. 7) A header row should be repeated on each page for improved readability. TABLE 1, STEADY-STATE: 1) Extreme event descriptions, item 2e ? why is this needed? How would this occur? What would be evaluated, high voltage? Stability issues? Note that it wouldn't be stability concern - this is the steady state table. 2) Extreme event descriptions, item 3b - how is this condition any different than what is studied in extreme event item 1 (N-2, no adjustment)? We suggest that item 3b be removed. 3) Extreme event descriptions, item 3c is too vague and it is suggested that it be removed. 4) Notes section (bottom of table), item 1 - Various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. Why include a discussion about delayed clearing in a steady-state table? 5) Notes section (bottom of table), item 4 ? We interpret FACTS to mean Flexible AC Transmission Devices and this means different things to different companies. FACTS devices can be series devices and not necessarily shunts as referred to in the table. It is noted that there is not footnote reference pointing to item 4 within the table. TABLE 2, Stability: 1) Planning Event P1 - Indicates SLG or 3-PH, which one is needed? This should be clarified in the requirements that reference this table. The intent is likely that most planners would perform the less labor intensive 3-PH simulation and if criteria were met, then the conclusion would be that SLG is also met. However, as presently written, the "OR" could be manipulated to allow someone to meet criteria for SLG but not the 3-PH. The requirements should provide clear

Organization	Question 7:	Question 7 Comments:
		expectations in this regard. (Same comment applies to P3 and P6) 2) Planning Event P1.2 - At what position on the line is the fault to be tested? Either the table or requirements that reference this Planning Event should be clear in what is required. 3) Planning Event P1.3 ? Is the fault to be placed on the high-side or low-side of the transformer? Either the table or requirements that reference this Planning Event should be clear. 4) Planning Events P1 and P2 - Is the intent that a TP would need to run all possible P1 and P2 events in dynamic stability simulations? If not, the requirements should be worded to allow the TP some flexibility in selecting the items having the most impact. To expect all of these events to be simulated within dynamics is unrealistic and unnecessary. 5) Planning Event P2.1 ? While we agree this event is warranted in steady-state, we question the need to cover this item within stability. Wouldn't breaker action clearing a fault always produce a more severe system disturbance than an inadvertent breaker trip? 6) Extreme Events ? The reference to R5.5.4 should be R5.4.4 7) Extreme Events - Items 2, a,b,c,d - should "protection system" be capitalized as the defined term in the NERC Glossary? 8) Extreme Events - Items 2f and 2gshould be removed. It is inconceivable that the simultaneous faults described could occur. 9) Notes section (bottom of table), item 1 - Does not read consistent with Note 1 from Table 1 Steady-State. As stated above, various topics are covered within this note - stuck breaker, breaker relay failure, normal clearing, delayed clearing - it should be broken up. 10) Note number 4 from Table 1 Steady-State (item on shunt/FACTS) is missing in Table 2. The first 5 notes from Table 1 should be reflected in Table 2 with the existing Table 2 note 5 being re-numbered to item 6. 11) Table 2 Note 5.a.ii. - We question whether the number of units totaling the Contingency reserve is a good criteria. Also, with regard to the phrase "the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements", we suggest a change to "the resulting power swing shall not cause the system to separate or form electrical islands".

Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments to do so and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table.

Organization	Question 7:	Question 7 Comments:

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE TO BOTH TABLE 1 AND TABLE 2:

1) The notes at the top of the table are intended for the Planning Events. The SDT has taken the advance offered by FE and others within industry and moved the "Planning Events" title to be positioned above the introductory notes.

2) Regarding prior Top note 2, now note "g". The SDT did not make the change recommended and believes both the Transmission Planner and Planning Coordinator criteria need to be considered and the more restrictive criteria applied if warranted. Generally, the criteria used for applicable facilities would be known and agreed upon between the Transmission Planner and Planning Coordinator, for example within an RTO environment.

3) Top Table note item 3 is now referred to as note "a". The inconsistency described by the commenter is now corrected with the single table format. Cascading is a defined term in the NERC Glossary of Terms.

4) The SDT has adjusted the top notes and refer to them with alpha character references to avoid confusion with the table footnotes that are referenced within the table.

5) The footnote reference to note 3 on the Header titled "Event" (column 3) of the prior Table version has been removed. The footnote recommended by the commenter is now used and is referenced as footnote 2 in the new table.

2. If the event analyzed involves BES elements at multiple System voltage levels, the lowest System voltage level for stated performance criteria applies regarding allowances for interruptions of Firm Transmission Service and loss of Non-Consequential Load.

6) Contingency P3 is considered a multiple Contingency event and as described in Requirement R3.4 the Transmission Planner is expected to cover those Contingencies "… that are expected to produce more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe System results." Therefore, the SDT agrees with the commenter that the Transmission Planner would not be required to run every generation outage in combination with an addition single Contingency.

7) The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 1:

1) The 2e Extreme Event came from the existing TPL standard, category D11 contingency. The SDT considers this to be more appropriate for steady state analysis than for Stability analysis and that the main intent is to guard against an extreme voltage rise.

2) The SDT agrees with FE related to Extreme Event item 3b and it has been removed in the new table.

3b. ~~Loss of two Transmission lines in different rights-of-way prior to System adjustments for conditions such as:~~

3) The SDT disagrees with the commenter that "Extreme event description item 3c is too vague and it is suggested that it be removed."

4) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 1 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were

Organization	Question 7:	Question 7 Comments:

NERC Glossary of Terms definitions and have been removed.

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. ~~The~~A stuck breaker ~~event~~ introduces a delayed clearing mode.~~ Normal Clearing is when the Protection System operates as designed and the Fault is cleared in the time normally expected with proper functioning of the installed protection systems. Breaker fail relay operation is a predetermined time that occurs after the Protection System operates and the breaker has failed. Breaker fail relaying will also isolate a predetermined portion of the electric system to isolate the failed breaker. Delayed clearing of a Fault is due to failure of any Protection System component that prevents the Protection System from operating normally.~~

5) The SDT has corrected the footnote reference to FACTS to better clarify that the SDT's intent of referring to only those FACTS devices which are shunt devices. The new footnote is footnote 7 and is now referenced within the Planning Event table information.

7. Requirements which are applicable to shunt devices also apply to FACTS devices that are connected to ground.

SDT RESPONSE TO THE COMMENTS MADE THAT ARE APPLICABLE ONLY TO TABLE 2:

1) The confusion in Planning Event P1 – indicating a "SLG or 3-PH" has been resolved and now more clearly indicates that a 3-PH fault must be passed. The P3 and P6 Planning Events now indicate the intent is to pass a SLG event for these items. However, as stated in footnote 3, if a Stability study indicates that criteria is met for a 3-PH analysis, the results of that test are sufficient to meet the less stringent SLG criteria.

2) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

3) This is left to the judgment of the Transmission Planner and the Planning Coordinator. It is expected that you study the worst case fault location.

4) It is not expected that a Transmission Planner would analyze every Planning Event scenario for P1 and P2 within a Stability study. Requirement R4.5 provides the Transmission Planner the flexibility desired by FE in selecting the items having the most impact.

5) No. Sometimes opening a breaker produces a more severe dynamic voltage swing than clearing a fault at that location. A fault can stimulate machine exciters into a faster response. A slower response from exciters due to opening a breaker can result in larger dynamic voltage swings.

6) The reference to requirement R5.5.4 has been removed as some commenters felt this created a circular reference between the table and the requirement language.

7) The commenter is correct that the term "Protection System" as used in Extreme (Stability) Events items 2, a,b,c,d is a NERC defined term in the NERC Glossary of Terms and is now correctly capitalized within these Extreme Event descriptions

8) Extreme (Stability) Events items 2f and 2g have been retained by the SDT and these items are consistent with the current FERC approved TPL-004 category D6 and D7. Other commenters have not objected to these items.

9) The SDT agrees that a variety of topics were covered in the prior footnote 1 of Table 2 and that a discussion on delayed clearing was not applicable to a steady-state table. We have revised this footnote which is now footnote 11 to focus on the stuck breaker topic. Many of the prior references in this note were NERC Glossary of Terms definitions and have been removed. The prior footnote 1 inconsistencies indicated by the commenter have been resolved by moving to

Organization	Question 7:	Question 7 Comments:
the single table format. 10) The SDT agrees that there were missing footnotes in Table 2 when compared to the prior Table 1 footnotes. This is no longer an issue in the single table format as only one set of footnotes is used. 11) The SDT believes that the Contingency reserve is the appropriate maximum amount of generation which should be allowed to be lost for Planning events P2-P7. Also, the SDT believes the appropriate performance requirement for Planning Events is for no additional lines to be allowed to trip due to apparent impedance swings.		
Orlando Utiliites Commission	Yes and No	I like the concept of the new performance tables however if they could be made shorter that would be handy. I have the following specific suggestions, although they may be moot if the table is redesigned. The way the notes at the top of table 1 and table 2 are written it appears that they apply to planning single, planning multiple and extreme event sub-tables. However this is in conflict with some parts of the standard itself and the team's comments on the conference call. For example Requirement R3.3.2.2 applies facility ratings only to planning single contingencies only, so which is correct the requirement or the note that applies it to everything? I have several suggestions to fix this: 1. Move the "notes" to under the Planning Event sub table 2. Making 4 tables with the Extreme Events being a table 2 & 4 respectively 3. Indicating the notes as only applying to specific planning events. The discrepancy between requirement R3.3.2.2, the table note and comments on the conference call also needs to be corrected either by expanding the applicability of R3.3.2.2 to multiple contingencies or reducing the scope of the corresponding note. It should be clarified somewhere that the Transmission Planner and Planning Coordinator select the range of the system contingencies for N-1. Otherwise some may interpret this as only having to test contingencies on their own system (insufficient from a reliability perspective for many systems) while some auditors may interpret this as requiring every possible n-1 in the US and Canada as necessary. For example a requirement R3.2.3 could be added stating "The planning assessment should include a technical rationale for the range of transmission lines, transformers and other equipment considered". This could also be handled as a note on the tables to the effect of "The study should include a technical rationale for the range of transmission line and generators considered."
Response: The introductory notes have been moved under the "Planning Event" portion of the performance table as suggested by the commenter. The notes apply to all Planning Events – system normal (n-0), single Contingency and multiple Contingency. The commenter raises a valid point of confusion related to allowable System adjustments as Requirement R3.3.2.2 seems to imply that the System adjustments may only be applicable for single Contingency. Redispatch of generation and other System adjustments are allowed for provided that all Facilities shall be operating within their Facility Ratings. The requirement has been removed and replaced with Table 1 header note "e" since the text in the former requirement was explanatory of what was allowed and not requirement language. **e.** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such		

Organization	Question 7:	Question 7 Comments:
adjustments are executable within the time duration applicable to the Facility Ratings. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. The list of Contingencies is expected to cover the Transmission Planner or Planning Coordinator system for which they are responsible for, including any tie-lines to adjacent Transmission systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for the adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.		
Entergy Services, Inc.	Yes and No	Given the type of information the SDT was trying to convey in the Tables, the format is fine. However, the enhanced standards create a conflict between the planning criteria used for evaluating transmission service (typically a standard N-1 thermal only analysis for ATC/AFC calculations) and the criteria for reliability as proposed by this standard. This disconnect will unfairly shift the cost of expanding the transmission system to the native load customers while wholesale and point-to-point transmission customers will reap the benefits of the additional capacity installed.
Response: The SDT has added footnotes 5 and 10 related to Firm Transmission Service. Footnote 5 indicates that interruption of conditional firm transfers is permitted for all Planning Events and footnote 10 indicates that interruption of Firm Transmission Service coupled with appropriate generation re-dispatch can be utilized for multiple Contingency events as a System adjustment, where indicated in Table 1 as being part of the Initial System Condition, and as a post-Contingency corrective action so long as no interruption of Non-Consequential Load occurs and all Facility Ratings are maintained. **5**. When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – 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 be considered.		
BPA Transmission Reliability Program	No	We suggest that the tables for Steady State and Stability Performance could be combined into one table, for simplicity. Separate columns could be used for Steady State versus Stability performance criteria.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments to do so and based on the SDT’s view that the Planning Events were the same for		

Organization	Question 7:	Question 7 Comments:
both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		
PPL EnergyPlus	Yes	The new format is a nice improvement. On the SDT conference call, it was stated that table 1 and table 2 assume different starting points; if so, could this be spelled out in the standard? Also, consequential generation loss isn't defined.
Response: The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled "Steady State and Stability Performance". The move to a single table was based on a significant number of comments and based on the SDT's view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages. The initial system conditions are described for each of the Planning Events and are the same for both steady-state and Stability. The SDT did not feel the need to define consequential generation loss for the standard.		
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
JEA	Yes and No	JEA can live with them as is, but would also welcome enhancements. Will defer enhancements to others.
Lafayette Utilities System	Yes	
Arizona Public Service Co.	Yes	We agrees with the proposed format changes of the Tables.
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	

Organization	Question 7:	Question 7 Comments:
E.ON U.S. Transmission Planning	Yes	
Response: Thank you for your response. The SDT has reformatted the performance tables (Table 1 Steady-State and Table 2 Stability) into a single table format based on commonalities between the two prior individual tables. The new Table 1 is titled “Steady State and Stability Performance”. The move to a single table was based on a significant number of comments and based on the SDT’s view that the Planning Events were the same for both Steady-State and Stability. For Extreme Events, the separation of Steady-State and Stability that many in industry seem to prefer for the two table format has been retained in the new table. The new single performance table is greatly condensed from the Draft 2 version and the entire body of material is now contained on three pages compared to the thirteen pages that the prior Table 1 and Table 2 encompassed. Headers are repeated on subsequent pages.		

8. A new definition for "Bus-Tie Breaker" was added to clarify the type of substation design and breaker position that qualify as a Bus-tie Breaker. Do you agree with the proposed definition? If not, please explain.

Summary Consideration:

Based on the comments received from the industry, the SDT has revised the definition of Bus-tie Breaker.

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

Organization	Question 8:	Question 8 Comments:
NPCC	No	The definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. NPCC Participating Members Recommend, "A circuit breaker that is positioned to connect two individual station configurations." We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
TVA System Planning	Yes	TVA does appreciate this clarification, but suggests the following wording: "A circuit breaker that is positioned to connect two individual straight bus substation configurations that if faulted results in both bus sections being cleared."
Omaha Public Power District	No	The term "straight bus" is not an industry-standard term. Replace "straight bus" by "single-bus, single-breaker".
Progress Energy Carolinas		The use of the word "straight" in the definition raised questions. We recommend the word straight be removed or change the definition to the following. "Bus-tie Breaker: A circuit breaker positioned to connect two individual buses with one or more other breaker positions on each bus. (Substation configurations such as a ring-bus, breaker-and-a-half, or double-breaker do not generally include bus-tie breakers.)"
Platte River Power Authority	Yes and No	Delete the sentence in parentheses.
BCTC	No	Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. What would these breakers be called? We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
Manitoba Hydro	Yes	The Bus-tie Breaker definition provides the clarification Manitoba Hydro requested in our draft 1 comments. However, we suggest the wording in brackets should be deleted as it is possible to add bus-tie breakers to schemes like the breaker-and-a-third bus in large stations.
Transmission Agency of Northern California	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
National Grid	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. We recommend modifying the definition to read, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
OPUC	Yes and No	A better definition of Bus-Tie Breaker might be: “A circuit breaker that divides a bus section with multiple tap off points into two bus sections.”
Pacific Gas and Electric Co.	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Public Service Company of New Mexico	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Puget Sound Energy, Inc.	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
Idaho Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SMUD	No	We do not disagree with the proposed definition change. However, we do not agree that “Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Hydro-Qu?bec Trans?nergie (HQT)	No	? The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. HQT recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
Sierra Pacific Power Comapny / Nevada Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Ameren	No	To provide clarity, a revised definition is proposed. "A bus-tie breaker is a circuit breaker that connects two individual bus sections with one or more breaker positions on each bus; substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers."
SRP	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.

Organization	Question 8:	Question 8 Comments:
MidAmerican Energy Company	No	MEC suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Tucson Electric Power Company	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
SERC Dynamics Review Subcommittee	No	The use of the word ?straight? in the definition raised questions. We recommend the word straight be removed or change the definition to the suggestion below: Suggestion: Bus-tie breakers are defined as a circuit breaker position that connects two individual buses with one or more breaker positions on each bus.
MRO NERC Standards Review Subcommittee	No	The MRO suggests applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Modesto Irrigation District	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Tri-State G&T	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Brazos Electric Power Cooperative,	No	Part of the definition of a bus tie breaker as outlined in this Standard should be that it is the ONLY connection between 2 substation buses. Not sure why the word 'straight' is used in this definition. If a bus with a 90 degree turn is connected to another bus by a single tie breaker, does this not apply? Also, breaker and a half schemes do

Organization	Question 8:	Question 8 Comments:
Inc.		sometimes have a bus tie breaker in them although its probably not common. Including those specifics in not needed.
ColumbiaGrid	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Southern California Edison	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two bus sections.
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
American Transmission Company	No	We suggest applying the proposed definition to a new term, "Straight Bus-Tie Breaker". The creation of a narrow, special application definition of "bus tie breaker" is generally confusing and misleading. The term "bus tie breakers" is widely used in the industry in the context of various bus configurations. In addition, this narrow definition may create confusion if other Standards refer to bus-tie breaker in a different context.
Duke Energy	No	The use of the word ?straight? in the definition raised questions and did not seem crucial to the definition. We recommend the word ?straight? be removed from the definition.
Central Maine Power Company	No	The definition provided is too limiting. It indicates that if a substation has two rings with a bus tie breaker in between, that breaker is no longer a bus tie breaker. Recommend instead, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
NSTAR Electric	No	The definition provided is too limiting and should be changed to "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus

Organization	Question 8:	Question 8 Comments:
		schemes together are bus-tie breakers."
New York Independent System Operator	No	The definition provided is too limiting. It says that if you have a two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. We do not agree that, "(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)", as we have examples where stations of this nature are connected through a single "bus-tie breaker".
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	To provide clarity, a revised definition is proposed. A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double-breaker do not have bus-tie circuit breakers.
Alberta Electric System Operator	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a-half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: "A circuit breaker that's only protective purpose is to isolate a segment of a bus."
ISO New England Inc.	No	he definition provided is too limiting. It says that if you have two rings with a bus tie breaker in between, it is no longer a bus tie breaker. Recommend, "A circuit breaker that is positioned to connect two individual station configurations. The breakers in a bus scheme are not bus tie breakers but the breakers that tie bus schemes together are bus-tie breakers."
Orlando Utiliites Commission	Yes and No	I neither for or against breaking out these breakers as a separate class. However a graphic or sketch of some example an easier concept to understand both in terms of what it is and why it is worthy of special attention.
Entergy Services, Inc.	No	Change term from ?Bus-tie Breaker? to ?Straight Bus Substation Bus-tie Breaker? with the following definition: A bus-tie breaker is a circuit breaker that connects two individual bus sections in a straight bus substation configuration. References to Bus-tie Breaker in the standard would also need to be changed accordingly.
US Bureau of Reclamation	No	We do not disagree with the proposed definition change. However, we do not agree that ?Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers. Some breaker-and-a half and double-breaker layouts may have bus breakers located mid-way in the side elements. We propose the following definition: A circuit breaker that divides a bus section with multiple tap off points into two

Organization	Question 8:	Question 8 Comments:
		bus sections.
BPA Transmission Reliability Program	No	The term "Bus Tie" implies tying any two buses together. However, the intent of this standard is actually referring to connecting the main buses of two adjacent main and auxiliary configured substations together. Therefore, we recommend changing the term "Bus Tie Breaker" to "Bus Sectionalizing Breaker". We also recommend removing the parentheses portion of the Bus Tie Breaker definition. It does not provide clarification and may not apply to all utilities' systems.
Response: The SDT has revised the definition as follows: **Bus-tie Breaker**: A circuit breaker that is positioned to connect two individual ~~straight bus~~ substation bus configurations. ~~(Substation configurations such as ring-bus, breaker-and-a-half, or double bus-double breaker protection schemes do not use bus-tie breakers.)~~		
Progress Energy Florida, Inc.	No	PEF understands the intent behind the wording of the definition, but neither agrees with the definition nor its use in various applications in the Standard. Bus tie breakers as defined in the draft Standard are limited to connecting two straight bus configurations. In reality, the term bus-tie breaker can be, and is used for other applications. PEF suggests that the SDT further research the use of this term in the industry. But more to the point, PEF does not see the need for a distinction between bus tie and non bus tie breakers and ultimately recommends that this be removed from the Standard.
Florida Power and Light	No	Bus tie breakers are defined exclusively to straight bus configurations. They can be used for other breaker configurations. We do not see the need for a distinction between bus tie and non bus tie breakers.
Response: The SDT notes that a number of commenters disagreed with the definition. However, the number who indicate that the distinction should be eliminated is in the minority. Therefore, the SDT has retained the distinction while having made changes to provide a simpler and broader definition of bus-tie breaker.		
Dominion - Electric Transmission Planning	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 8:	Question 8 Comments:
Los Angeles Department of Water and Power	Yes	
Tenaska, Inc.	Yes	
Gainesville Regional Utilities	Yes	
JEA	Yes	
PacifiCorp	Yes	We agree with the proposed format changes of the Tables.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Lafayette Utilities System	Yes	
Black Hills Corporation	Yes	
Arizona Public Service Co.	Yes	We agree with the proposed definition change.
Exelon Transmission Planning	Yes	
Austin Energy	Yes	
Midwest ISO	Yes	This is a good definition.

Organization	Question 8:	Question 8 Comments:
Tri-State Generation and Transmission Association, Inc.	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
IESO	Yes	
E.ON U.S. Transmission Planning	Yes	
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
FirstEnergy Corp.	Yes	
Response: The SDT thanks you for your response but the majority of commenters expressed a desire to change the definition.		

9. **Some commenters questioned why a Bus-tie Breaker would have a different performance requirement than a non-Bus-tie Breaker, stating that all breakers have the same probability for failure. It may be true that generally the probability for failure of any given breaker would not vary substantially among similar types of breakers, but the Bus-tie Breaker reduces exposure and consequences of bus faults. The different performance expectations in Tables 1 and 2 are based on promoting a higher level of reliability for the Transmission Systems operated above 300 kV.**

   It is recognized by the SDT that a straight bus design has some undesirable exposure to bus faults, but that Bus-tie Breakers can be utilized to improve reliability for bus faults and problems associated with exit breakers. As a result, the risk of an internal breaker fault was deemed to be significantly less than the benefit that is gained by reducing the exposure to a total bus failure. Therefore, provisions were built into the performance requirements that would not discourage their use.

   Do you agree that non-Bus-tie Breakers rated above 300 kV should have more stringent performance requirements than Bus-tie Breakers? If not, please explain why and/or suggest specific changes.

Summary Consideration:

While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines in the Table.

Due to industry comments, the SDT has changed/added the following:

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm transmission service is allowed

Footnote #10 – 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 be considered.

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

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

Load Reduction: Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event.

Supplemental Load Loss: Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.

Organization	Question 9:	Question 9 Comments:
TVA System Planning	No	Since an internal fault on any breaker is a low probability event, we believe that Non-consequential Load Loss should be allowed.
Alberta Electric System Operator	No	We believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class.
Response: While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
BCTC	Yes	BCTC agrees with different performance levels. However, we have a different rationale. Our reasoning is that a bus fault has a lower probability than a line fault. Bus tie breakers are called on to interrupt faults less often than line breakers. The failure probably may be the same but the frequency of failure is lower (because they are not called on to operate as often). The explanation given above by the SDT appears to be more related to a WECC issue that bus breaker failure should be Category D.
Response: Thank you for your support of the SDT’s position.		
Platte River Power Authority	No	I think the performance for non-bus-tie breakers should be the same for all BES voltages for the same reason I agree with the performance of P2.4 Internal Breaker Fault (bus tie) and P4.6 Stuck Breaker where the Stuck Breaker could be a bus-tie or "sectionalizing" breaker.

Organization	Question 9:	Question 9 Comments:
Manitoba Hydro	No	Based on industry outage statistics, event P4, the non-bus tie breaker failure has a lower probability of occurrence than event P7, the common structure event. Consequently, Manitoba Hydro recommends that the performance requirement for >300 kV should be the same as P7. Imposing a higher performance expectation on the >300 kV facilities will require significant bus reconfiguration costs to ensure compliance for existing stations. The additional cost can not be justified by the reliability gain given the low probability of the event.
Transmission Agency of Northern California	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Pacific Gas and Electric Co.	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Public Service Company of New Mexico	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
PacifiCorp	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Idaho Power Company	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes

Organization	Question 9:	Question 9 Comments:
SMUD	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Sierra Pacific Power Company / Nevada Power Company	Yes	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Black Hills Corporation	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Arizona Public Service Co.	No	We do not agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
SRP	Yes and No	We interpret ?exit breakers? to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MidAmerican Energy Company	No	MEC recognizes that the addition of this requirement is an attempt to raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.

Organization	Question 9:	Question 9 Comments:
Tucson Electric Power Company	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
MRO NERC Standards Review Subcommittee	No	The MRO recognizes that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. There should be a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Modesto Irrigation District	Yes and No	Comments: We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Tri-State G&T	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
ColumbiaGrid	Yes	Please explain/define the term “exit breakers”. We agree with the rationale for the requiring more stringent performance requirement levels for non-bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes.
Southern California Edison	Yes and No	We interpret “exit breakers” to mean a breaker on an element that comes in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly

Organization	Question 9:	Question 9 Comments:
		different for different voltage classes
American Transmission Company	No	We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent non-bus-tie performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurance) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of this performance criteria before it is adopted.
Entergy Services, Inc.	No	The probability of an EHV breaker failure is extremely low. Statistically, the probability of an internal breaker failure on any given day in our system is approximately 1 failure every 10,000 days. The probability of a stuck EHV breaker in our system is approximately 1 failure every 21,000 days. While the impact of such events can be severe, the significant cost to remedy such low probability events seems unlikely to pass any reasonable cost/benefit analysis.
US Bureau of Reclamation	No	We interpret “exit breakers” to mean a breaker on an element that come in from outside the substation. We agree with applying less stringent performance requirements to bus tie breakers above 300 kV. Further, we believe that Non-Consequential Load Loss should be allowed for loss of either Bus-Tie or Non-Bus-Tie Breakers regardless of voltage class. The SDT has not presented evidence that the probabilities of failure for breakers within the same substation are significantly different for different voltage classes
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Los Angeles Department of Water and Power	No	The arbitrary separation based on voltage class is discriminatory and without any scientific or historical basis. The probability of breaker failure do not increase with voltage class. In fact, breaker failures are seldom heard of at above the 300kV classes. Most breaker failures occur in lower voltage classes such as 230kv, 115kv, etc. where the short circuit current tends to be higher and thus stressing breaker contacts more severely giving rise to breaker failures. Delete any separation of voltage classes.
Response: The SDT believes that the separation for a more stringent requirement at above 300 kV is not “arbitrary”. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems		

Organization	Question 9:	Question 9 Comments:
operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The SDT believes that the separation above 300 kV is not "discriminatory" in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Finally, the SDT believes that there is scientific and historical basis in the sense that our representation of the differences between Systems above 300 kV as opposed to below 300 kV are a reasonable review of the uses of the NERC-wide Transmission System including scientific and historical considerations. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
National Grid	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
Central Maine Power Company	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.
NSTAR Electric	No	They should have the same performance requirements. The performance standards should not encourage differential treatment for the same equipment.
FirstEnergy Corp.	Yes and No	Fundamentally, from a purest perspective, we believe that all breakers should be treated as having the same probability of failure. However, we understand the SDT's intent and agree to the higher performance expectations for the above 300kV transmission system. We also agree that without the exception provided for bus-tie breakers, some entities may take the approach to simply operate their bus-tie breakers open in order to meet the performance requirements, which would be counterproductive to the improved reliability sought by the team. The alternative would be back to back bus-tie breaker installations which may not even be feasible due to space limitations. On a going forward basis, future station designs at this voltage level should avoid straight bus designs.
ISO New England Inc.	No	They should have the same performance requirements, however we understand that it is better to encourage bus-tie breakers in some applications than to hold them to the higher standard. Future station designs that need this differential treatment should be discouraged.

<table>
<tr><th>Organization</th><th>Question 9:</th><th>Question 9 Comments:</th></tr>
<tr><td>Northeast Utilities</td><td>Yes</td><td>Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.</td></tr>
<tr><td colspan="3">Response: The SDT understands your comment as being supportive of the more stringent requirement for non-Bus-tie Breakers above 300 kV and of a more stringent requirement for Bus-tie Breakers above 300 kV in new substations. While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement for non-Bus-tie Breakers above 300 kV and for a lower performance requirement for Bus-tie Breakers above 300 kV. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of Bus-tie Breakers above 300 kV for new substations.</td></tr>
<tr><td>Tenaska, Inc.</td><td>Yes and No</td><td>Voltage is a questionable criteria for determining whether a breaker's performance requirements should be different. May want to consider a lower voltage cutoff (below 100 or below 200) as lower performance MAY have less of an impact.</td></tr>
<tr><td colspan="3">Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV and has not raised the system performance requirement for loss of breakers at lower voltages.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>Yes</td><td>Our control area operates at 138 kV. Does everyone think that holding the owners of above 300 kV operating voltage systems to a higher standard really increases the total BES reliability? Does giving the DC systems a pass on some of the requirements really make sense in the world of reliability?</td></tr>
<tr><td colspan="3">Response: The SDT believes that holding the owners of above 300 kV operating voltage systems to a higher standard increases the total BES reliability. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.</td></tr>
</table>

Organization	Question 9:	Question 9 Comments:
Progress Energy Florida, Inc.	No	PEF is opposed to distinction between non-Bus-tie breakers and Bus-tie breakers, and furthermore is opposed to the more stringent requirements for both in facilities above 300 kV. One primary reason has already been acknowledged by the SDT, that breakers have the same failure rate no matter the configuration in which they are placed. PEF can see two potential outcomes to the missteps being made regarding the breaker distinction: a) multiple redundancy of breakers for both Bus-tie and non-Bus-tie breaker schemes, which will require tearing down many Substations, acquiring additional property in many cases, and completely rebuilding the Substations to allow room for redundancy of breakers in series with one another; b) choosing to remove existing breakers for which a scenario of non-compliance is imminent, which could potentially pose a reliability risk to the system and possibly result in heightened risk for other Event categories.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT understands your argument about discouraging the use of breakers with a higher breaker failure performance requirement. However, the SDT notes that the Transmission Planner has always needed to plan for breaker failure since it is an event that does occur. Any reliability risk that is created by taking a breaker out of service to respond to this new higher performance requirement should be covered by the responsible entity by conducting system analysis using the new standard. If the reliability risk created by eliminating a breaker results in a failure to meet the performance requirements as outlined in the new standard, then the responsible entity will be required to develop Corrective Action Plans to mitigate the risk.		
Lafayette Utilities System	No	See paragraph (b) in response to Question 15.
Response: Lafayette Utilities System indicated in paragraph b in response to Question 15 that “Adopting less stringent performance requirements for loss of elements below 300 kV may be discriminatory.” Lafayette Utilities System further indicated that this may be because more wholesale customer Load may be served at these lower voltages than Transmission Owner Load. The SDT believes that the separation above 300 kV is not “discriminatory” in that the standard is intended to be in place for all operators, owners, and users of the Transmission System. Further, the SDT disagrees with the notion that it may be discriminatory in that more wholesale Load is served from under 300 kV than the Transmission Owner’s Load. As indicated in the SDT’s responses to the comments of others, the SDT believes that systems operating above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers.		

Organization	Question 9:	Question 9 Comments:
Ameren	Yes and No	Yes: The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. No: However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. On the Ameren system, there is no indication that transmission system reliability has been degraded through the use of straight bus configurations. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
North Carolina Electric Membership Corp	Yes and No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to

Organization	Question 9:	Question 9 Comments:
		justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	The installation of bus-tie circuit breakers in a straight bus configuration would reduce exposure to a) bus faults or to b) line faults with breaker failure without adding much risk for internal fault in the bus-tie breaker. Those entities that employ a straight bus substation design with bus-tie breakers have recognized that failure of the bus-tie breaker, a very low probability event, would result in the loss of multiple transmission elements and perhaps firm load for a short time until the bus sections can be restored, but bus-tie breakers are an investment worth the risk. Therefore, it is generally agreed that the outage of non-bus-tie circuit breakers should have higher performance requirements than the outage of bus-tie circuit breakers. The SDT should be commended for this change since the previous draft version. However, it is not clear that adopting a higher standard of performance for planning events involving transmission facilities 345 kV and above will improve overall system reliability. Some areas of the continent already have n-2 planning criteria, yet these systems have still experienced significant outages including blackouts. It is suggested that a review of the Transmission Availability Data System (TADS) data, when available, should be conducted to help assess what system performance requirements need to be strengthened before arbitrarily determining to "raise the bar" for certain voltage levels and system designs. The industry should not be forced to invest a great deal of capital to meet a new standard requirement when it would not have an immediate impact on system reliability. Some sort of cost/benefit analysis should be performed to justify any change from the present TPL-001 through 004 standard requirements. Also, further clarification is required to explain how to drop consequential load without cutting firm transmission service to those affected/outaged customers, and this needs to be added to the notes in Tables 1 and 2.

Response: The SDT thanks you for your support with regard to the reason for a less stringent requirement for Bus-tie breakers**.** The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. Cost estimates were requested in other questions and were utilized by the SDT in determining a balance between such costs and reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.

The SDT understands your issue with regard to explaining the dropping of consequential Load without cutting Firm Transmission Service to those affected/outaged customers. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm

Organization	Question 9:	Question 9 Comments:
		transmission service is allowed. **Footnote #10** – 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 be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.
Florida Power and Light	No	These provisions made to not discourage the use of bus tie breakers will also not discourage the use of the single breaker/single bus substation arrangement which can have very severe consequence when used on critical BES substations. The TPL-001-1 draft also sets a threshold of higher performance to facilities above 300 kV than previously established in the existing standard. We do not agree that such a threshold is necessary or warranted. Requirements which are more stringent for these facilities may wrongly influence decisions on project alternatives in favor of facilities with less stringent requirements. Related to the more stringent requirements for facilities above 300 kV, FPL also disagrees with the performance requirements contemplated by the proposed draft standard for DC lines. The SDT stated performance requirements for DC lines as currently drafted, is discriminatory as compared to AC line performance, and needs to be addressed. This could be viewed as an exemption for DC lines and violates FERC's comparability principle as it relates to reliability performance. The TPL-001-1 draft sets a lower performance requirement for the loss of a single pole of a DC line than in the existing standard by allowing interruption of firm transfer if the transfer is deemed to be dependent on the outaged line. Firm transfers are also dependent upon AC lines. The proposed standard does not distinguish between asynchronous DC ties and the more common parallel connected DC tie. With an asynchronous DC tie, the transfer is lost with the tie, which is analogous to Consequential Load Loss which is already allowed. With a parallel DC

Organization	Question 9:	Question 9 Comments:
		tie, the transfer will be shifted to the parallel AC system and should have the same performance requirements. We do not agree that such an exception for DC lines is necessary or warranted. The decision in selecting DC vs. AC in transmission lines has traditionally been based on the break-even cost and performance of the two alternatives. The lower performance requirement may wrongly influence decisions on project alternatives in favor of DC facilities because of the less stringent reliability performance requirements.
Response: The SDT understands that the standard as drafted does not discourage the use of straight bus arrangements below 300 kV by allowing interruption of Firm Transmission Service and Non-Consequential Load Loss for all P4 events below 300 kV. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. A number of commenters raised concerns with the less stringent requirement for DC systems. The SDT has removed the less stringent requirements for DC lines.		
Tri-State Generatino and Transmission Association, Inc.	No	Performance requirements should depend on the potential loss of load impact of a breaker failure, not the voltage level.
Response: The SDT believes that while theoretically there would be potential merit in a loss of load impact approach to performance requirements for breaker failure; it would result in performance requirements that would be difficult to enforce. For example, such an approach would require completing estimates of the loss of Load for Contingencies for various conditions and then documenting it. The auditor would need to review these estimates as well as the documentation to become convinced that the correct performance requirement was used for each breaker. This review would need to be in addition to any other activity performed by the auditor to ensure compliance with the standard. The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		

Organization	Question 9:	Question 9 Comments:
Brazos Electric Power Cooperative, Inc.	Yes	Yes but this seems to add another category of items to provide for in the assessment.
Response: Thank you for your support.		
IESO	No	We hold the view that all breakers can be exposed to the same types of event, i.e., they can have internal faults and can be "stuck" when attempting to open as instructed. As such, there should not be any difference in the expected system performance among them in response to system events, and regardless of the voltage levels. We suggest the SDT to revised Tables 1 and 2 such that their expected performance are identical.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV.		
Duke Energy	No	In Table 1, Category P4, Events 1 through 5 addressing a stuck non-bus tie breaker >300kV should allow Interruption of Firm Transmission Service and Non-Consequential Load Loss, because P4 addresses a multiple contingency.
Response: The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. While a significant number of parties commented negatively about the higher performance requirement for non-Bus-tie Breakers above 300 kV, higher performance requirements are encouraged by FERC Order No. 693 and the majority of the industry has indicated support for the higher performance requirement. Therefore, the SDT has kept the higher performance requirement for non-Bus-tie Breakers above 300 kV. The SDT recognizes that Duke Energy has indirectly brought up the issue as to how the interruption of Firm Transmission Service relates to the dropping of Load in its comment. The SDT has made changes to footnotes 5 and 10 in the table and revised the definition of Consequential Load Loss and Non-Consequential Load Loss to clarify the issue. **Footnote 5 -** When the conditions and/or event(s) being studied form the basis for conditional firm transmission service, curtailment of that conditional firm		

Organization	Question 9:	Question 9 Comments:
transmission service is allowed. **Footnote #10** – 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 be considered. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~ **Load Reduction:** Load that is still connected to the System, but is reduced due to lower voltage conditions following a Planning or Extreme Event. **Supplemental Load Loss:** Load that is disconnected from the network by end-user equipment responding to post-Contingency System conditions.		
Orlando Utilities Commission	Yes and No	If they are going to be two classes of equipment with an arbitrary cut off 300 kV is a good cutoff. However I would prefer to see the decision on what is "super BES" and regular "BES" less arbitrary and more reliability driven, such as letting the regions define this cut off just as they define BES in a manner suitable to the design of their regional system.

Response: The SDT believes that the separation for a more stringent requirement above 300 kV is not "arbitrary". The SDT feels the 300 kV and higher systems generally represent an extra-high-voltage (EHV) range that is considered the backbone of many systems in the various Interconnections. Systems operated at this range generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers which then deliver the power among other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability.

The SDT is preparing a NERC-wide standard for which a region can submit a regional difference that is justified based upon physical differences in that region and/or to result in a regional difference that is a higher performance requirement than the NERC-wide standard. Therefore, if a region has good cause for a different "cutoff", then the region can submit a regional difference through the NERC standards development process. This regional difference could even be submitted as part of this standards writing effort. However, it should be noted that once the regional difference is approved through the NERC standards development process, then it will be submitted to FERC and other regulatory authorities for approval.

While there are a significant number of parties that commented negatively about the higher system performance requirement for non-Bus-tie Breakers above 300

Organization	Question 9:	Question 9 Comments:
kV, higher performance requirements are encouraged by FERC Order No. 693 and the industry has indicated support for the higher performance requirement. Therefore, the SDT has not altered the higher system performance requirement for loss of non-Bus-tie Breakers above 300 kV.		
BPA Transmission Reliability Program	Yes	In general, performance requirements should be more stringent for higher voltage systems. Therefore, we agree that non-bus-tie breakers above 300 kV should have more stringent requirements.
Dominion - Electric Transmission Planning	Yes	
NPCC	Yes	
City Water, Light & Power - Springfield, Illinois	Yes	
Progress Energy Carolinas	Yes	
JEA	Yes	
Puget Sound Energy, Inc.	Yes	We agree that the failure of non-bus tie breakers above 300 kV to operate can have much higher consequence.
ITC Holdings: ITC, METC, ITC Midwest	Yes	
Tacoma Power	Yes	
Hydro-Quebec TransEnergie	Yes	

Organization	Question 9:	Question 9 Comments:
(HQT)		
Exelon Transmission Planning	Yes	
SERC Dynamics Review Subcommittee	Yes	The logic and the proposal seem reasonable.
Austin Energy	Yes	
Arkansas Electric Coop. Corp.	Yes	
Midwest ISO	Yes	
AEP	Yes	
Lakeland Electric	Yes	
Southern Company Transmission	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	Comments: PJM supports the use of bus tie breakers.
E.ON U.S. Transmission Planning	Yes	

Organization	Question 9:	Question 9 Comments:
ERCOT System Planning	Yes	
Oncor Electric Delivery	Yes	NA
Response: Thank you for your response.		

10. The SDT made modifications in this second draft to the requirements relating to sensitivity cases. Do you concur with the modifications reflected in Requirements R2.1.3 and 2.1.4? If not, please state why and/or suggest specific changes.

Summary Consideration:

A number of commenters agreed with the concept of the sensitivity analysis but were concerned that there is a conflict with sensitivities already included in base studies, sensitivity details, explaining why sensitivities were not run and how they affected Corrective Actions. The SDT has made the following changes:

1 – Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required year for steady state and Stability. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.

The revision also includes the removal of the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances.

2 – The sensitivities listed in Requirement R2.1.3 were revised for clarity; however, the SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

3 – Requirements R2.1.4 and R2.4.4 that require explanation of performing additional sensitivities that are not listed in Requirement R2.1.3 have been deleted.

4 – Requirement R2.6 has been revised for clarity. The entity can use any sensitivity studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan.

The following requirements were changed due to industry comments:

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

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

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

R2.7 (now R2.6) For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System 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:

Organization	Question 10:	Question 10 Comments:
Dominion - Electric Transmission Planning	No	We are of the opinion that the proof of a negative that is required for sensitivity cases (i.e. - that the sensitivity cases were more severe for those selected conditions vs. those not tested) is burdensome. The burden of proof lies on the transmission planner.
NPCC	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Hydro-Qu?bec Trans?nergie (HQT)	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, are we to assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system?
Northeast Utilities	No	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity 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".

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

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

<table>
<tr><th>Organization</th><th>Question 10:</th><th>Question 10 Comments:</th></tr>
<tr><td>TVA System Planning</td><td>No</td><td>We recommend that sensitivity studies not be required for each of the near term years as required in R2.1.3 and R2.1.1. Sensitivities should only be required for only one year in the near term.   These sensitivity study requirements are too prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Sensitivity studies of load variation are inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system.</td></tr>
<tr><td colspan="3">Response: The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “~~s~~ensitivity 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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”. In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.

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

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:</td></tr>
<tr><td>Progress Energy Carolinas</td><td>No</td><td>These requirements are overly prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. Proper consideration and selection of the most appropriate sensitivities is within the engineering judgment of the Transmission Planner and Planning Coordinator. Singling out and creating sub-requirements for the sensitivities listed in the current TPL draft creates a special focus on these specific sensitivities that may not be warranted for a given system. This could easily lead to an over focus on these particular issues to the detriment of overall system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.</td></tr>
<tr><td colspan="3">Response: The SDT believes that sensitivities are necessary and consistent with the requirements of FERC Order 693. The draft standard includes the</td></tr>
</table>

Organization	Question 10:	Question 10 Comments:
requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii "Sensitivity studies and critical system conditions", FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. In addition to the firm obligation scenario, the portfolio of analyses should be supplemented to include information from sensitivity analysis. The sensitivity analysis should be developed using additional cases that simulate reasonably stressed System conditions. The SDT has included several parameters that can be varied to create the requisite sensitivity case(s). Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity 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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Los Angeles Department of Water and Power	No	R2.1.3 and 2.1.4 deal with operating scenarios that need to be studied by operating engineers under TOP but is duplicative and serve no useful purpose when performed by planning engineers for the purpose of future expansions. Transmission planning is to ensure that future system is expanded to handle expected system growth. Mixing operating studies in the planning of future system shows a confused perspective on the different roles between operating studies and planning studies. A responsible utility must perform both types of studies but they should not be mixed together or be required under two different standards, the TOP and TPL. The consideration of load variations, different dispatching scenarios, planned or unplanned transmission outages, system expansion not coming in on schedule, etc., are operating issues that should be and must be addressed in operating studies, and the proper place is in TOP, not TPL.
Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning.		
Transmission Agency of Northern	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

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California		these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities”. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Pacific Gas and Electric Co.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Public Service Company of New Mexico	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how

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PacifiCorp	Yes and No	We generally agree with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the “base case” of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the “base case” condition.? R2.7 also states that Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the “base case”, will the judgment of the TP be then questioned because of it’s sensitivity “base case” and not a 50/50 base case?
Puget Sound Energy, Inc.	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the “base case” of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance?

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		R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities”. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Idaho Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans.If a Transmission Planner performs studies on the “base case” of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Sierra Pacific Power Company / Nevada Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage

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Black Hills Corporation	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Arizona Public Service Co.	Yes and No	We generally agrees with the concept of the sensitivity analysis. However, clarifications of the following is needed: For example, if a TP performs studies on the ?base case? of which the loads are 90/10, does this constitute a sensitivity analysis. If so, will the TP have to then perform additional less stringent studies at the 50/50 load level to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the TP should not have to explain why they feel that this higher level (90/10) of load is the “base case” condition. R2.7 also states that

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		Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a TP that has built transmission based on the 90/10 load assumed in the ?base case?, will the judgment of the TP be then questioned because of it's sensitivity "base case" and not a 50/50 base case?
SRP	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tucson Electric Power Company	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

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Modesto Irrigation District	Yes and No	We generally agree with the concept of the sensitivity analysis since this is a standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the “base case” of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the “base case”, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Tri-State G&T	Yes and No	e generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

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Southern California Edison	Yes and No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans .If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the "base case" condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the "base case", will the judgment of the Transmission Planner be then questioned because the "base case" used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?
Alberta Electric System Operator	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for

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US Bureau of Reclamation	No	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 9 of 12 why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition. R2.7 also states that "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities". Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the ?base case? used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case?

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

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

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

The SDT agrees and has deleted Requirement R2.1.4.

Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and

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past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System 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:		
National Grid	No	a. With respect to R2.1.3., delete "... that Stress the System with sensitivities ...". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: a. and b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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”. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: c. Requirement R2.1.4 has been deleted.		
Gainesville Regional Utilities	No	If the RRO or the larger neighboring utilities agree, See Comment 1, it should be unnecessary for the smaller utility to performance any sensitivities except for those agreed to and performed by the RRO level. If the smaller utility has any of their elements that create issues in these regionally conducted sensitivities, then they could be accountable for providing potential remedies (most sensitivities do not necessarily require a remedy or project, per say). The variety of sensitivities suggested to be performed for a smaller utility probably will not add any reliability to the regional BES while the effort will take up a very large amount of the smaller utilities' manpower resources.
Response: All planning entities need to follow the same set of requirements. Smaller entities may not have the resources to perform some studies but can depend on and point to studies run by larger surrounding entities to satisfy their planning requirements.		

Organization	Question 10:	Question 10 Comments:
JEA	Yes and No	Will stress JEA resources to provide auditable evidence depending on the final measure applied.
Response: The SDT believes that sensitivities are necessary and consistent with the requirements in FERC Order 693. The draft standard includes the requirement, as specified in FERC Order 693, that planning decisions be based on a portfolio of analyses. In section 12.a.ii “Sensitivity studies and critical system conditions” FERC provided direction to consider a full range of variables considered to be significant that need to be assessed and documentation provided that explains the rationale for the selection of variables assessed. The standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.		
ITC Holdings: ITC, METC, ITC Midwest	No	While we appreciate that the addition of sensitivity studies is commendable and agree with 2.1.3 and 2.1.4 per se, the later clarification in R2.7 that “Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities” negates project justification (to many) based on sensitivity studies. Explaining as per R2.4.3 the reasons why you did or did not run a sensitivity study is less important, in many respects, than why you did or did not provide a Corrective Action Plan for performance failures observed in sensitivity studies. I.e., the study is the “cart” and the CAP is the “horse”. Hence, at a minimum some form of Corrective Action Plan should be required.
PPL EnergyPlus	Yes and No	All of the sensitivity requirements should be structured to keep sensitivities from forcing un-needed construction. R2.1.3 & 4 are a good step but the point about planning around the base case might be made even more forcefully.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”. Embedding the sensitivity in the “base case” will result in a CAP that addresses the particular “sensitivities”. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: In addition, Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance		

Organization	Question 10:	Question 10 Comments:
requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System 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:		
SMUD	Yes and No	We agree. However, the conditions listed in R3.5.1, R3.5.2 and R3.5.3 are applicable to the overall TPL Standard. Their specific listing in R3.5 gives the impression that these Requirements are only applied to R3.5 and not to the other Requirements in this Standard. In other words, are there any Requirements in this Standard that R3.5.1, R3.5.2 and R3.5.3 do not apply to? Therefore, we suggest TPL-001-1 be silent on this issue and move R3.5.1 through R3.5.3, (and the equivalent in the stability study R5.4.3.1 through R5.4.3.3) to a Requirement applicable to Assessment studies in general, such as the bullet points in the Performance Tables .Added Reference 3.5.1: In cases where an SPS is deployed to reduce thermal overloads such that flows are brought within established facility ratings, but, for a short duration (seconds) until it is fully executed, the facility flows exceed the established rating, is that considered a violation or an acceptable engineering judgment that facilities are judiciously being brought to operate within ratings? Or, should the facility owner ensure establishment of a documented rating even for the short duration of seconds? Q10:TSS response: We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. It is ambiguous from a criteria perspective, however, what role is played by the sensitivities in developing Corrective Action Plans and what risks are created by misapplication of the intent of such sensitivity analyses. Clarification of the following is needed along with examples of applicable sensitivities and how these would be factored into Corrective Action Plans. If a Transmission Planner performs studies on the ?base case? of which the loads represented are 1 in 10 year adverse weather condition (10% chance that the actual load may exceed the projected load), does this constitute a sensitivity analysis. If so, will the Transmission Planner have to then perform additional less stringent studies at the load levels representing 1 in 2 year adverse weather conditions (50% chance that the actual load may exceed the projected load) to demonstrate compliance? R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the “base case” condition. R2.7 also states that ?Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities?. Consider a Transmission Planner that has built transmission based on the 1 in 10 year adverse weather load assumed in the ?base case?, will the judgment of the Transmission Planner be then questioned because the “base case” used is equivalent to a sensitivity case and not a 1 in 2 year adverse weather base case? Is some Non-Consequential Load Loss for an N-1 contingency on a sensitivity case using an extremely high load forecast acceptable as a Corrective Action Plan in the planning phase?
Response: The SDT agrees with your comment and has deleted Requirements R3.5.1, R3.5.2 and R3.5.3. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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		

Organization	Question 10:	Question 10 Comments:
studies shall be included in the Assessment". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted Requirement R2.1.4. Requirement R2.7 (now R2.6) has been revised for clarity. The entity can use any sensitivities studies it has performed in conjunction with the required current and past studies to develop its Corrective Action Plan. **R2.6** For Planning Events shown in Table 1 ~~– Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in the tables, the Planning Assessment shall include Corrective Action Plans addressing how the performance requirements will be met. Revisions to the Corrective Action Plans are allowed in subsequent assessments but the System 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:		
Progress Energy Florida, Inc.	No	PEF has significant concerns with each of the sub-Requirements listed in R2.1.3. Each is ambiguous, vague and open to variations in interpretation. It therefore makes no sense that "documentation of the technical rationale for why each of the conditions was or was not selected" is a requirement. Indeed, given that all of the sub-Requirements of R2.1.3 are vague, unspecific, unwieldy concepts, PEF is not sure how said documentation could be accomplished. Concerning R2.1.4, PEF has the same concerns that were expressed regarding the modified requirements mentioned in Question 2, and similarly here would suggest a substitute to the language in R2.1.4. Significant concerns with the previous sub-Requirements notwithstanding, PEF suggests either returning to the language in each existing Standard's R1.3.2, or adding an R2.1.3.8 that states "Other known critical system conditions specific to the system studied by the Transmission Planner or Planning Coordinator."
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. In addition, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the System responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

Organization	Question 10:	Question 10 Comments:
~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lafayette Utilities System	No	As to the performance of sensitivity analyses under R2.1.3, Lafayette believes that insufficient detail is provided to define with clarity cases that involve ?modification of expected transfers? (per R2.1.3.2). For example, it is unclear whether the phrase ?modification of expected transfers? is intended to refer to a change in directional bias in the model, a reduction in flows due to variation between reservations and schedules, or something else. Additional definition should be provided to ensure that sensitivity cases performed pursuant to R2.1.3.2 are meaningful and useful.
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		
Ameren	No	Similar to our comment above for R2.4.3, there should not be a requirement to explain why sensitivities were not selected. Also, it is not clear if R2.1.4 is a requirement or an option. While we agree that the system cannot be adequately planned based on a single snapshot of expected system conditions, these items in R2.1.3.1-7 are too prescriptive and are inappropriate for inclusion here. The sensitivities listed appear to be options and not sub-requirements, and may result in over-focusing on the particular issues listed to the detriment of overall system reliability. Some sensitivity studies are in effect adding an additional level of contingency to the analysis work (n-2 or n-3). Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future system with and without the proposed new equipment. Engineering judgment should be used to develop the sensitivity scenarios, and it should be encouraged that the same scenarios should not be performed every year so that a portfolio of sensitivity scenarios would be developed over time. The standard should not include an enumerated list of required sensitivities. If two sensitivities are required to be performed each year, then the standard should state so, but we believe that more than one sensitivity scenario for each peak and off-peak case per year for assessment is too burdensome to run complete contingency analyses. Proposed alternative wording for R2.1.3 which addresses above concerns is as follows:R2.1.3. "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System to reflect one or more conditions such as variation in load assumptions, modification of expected transfers, variability and outages of reactive resources, generation additions, retirements, or other dispatch scenarios are integral to a thorough assessment of reliability. Document how and why appropriate sensitivities were selected."
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.		

Organization	Question 10:	Question 10 Comments:
Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “~~s~~ensitivity 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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”. In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Florida Power and Light	No	The words ?documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied? should be removed from R2.4.3. The sensitivity selection is necessarily subjective and judgmental. It is not clear what constitutes a valid rationale document. Compliance assessment of such a document would be subjective and is not needed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Exelon Transmission Planning	No	We support efforts to improve load and dynamic load modeling, however we have concerns in being able to do so in an accurate manner - See comments to question #2. The state of industry development is such that this is not ready for inclusion in a standard such as R2.4.1 and R2.4.3.1.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the system will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that “an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable”.		

Organization	Question 10:	Question 10 Comments:
R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable		
CenterPoint Energy and CPS Energy	No	We believe R2.1.3 and R2.1.4 are overly prescriptive and should be deleted. It requires engineering judgment and experience to know whether a planning analysis is materially impacted by certain assumptions and, if so, which sensitivity analyses should be performed. Literally interpreted by an auditor, R2.1.3 would require at least one sensitivity analysis for each one of the contingencies shown in Tables 1 and 2 for each study specified in R2.1.1 and R2.1.2 and documentation for each contingency of each study why each sensitivity specified in R2.1.3 was or was not selected. The likely result is not value-added engineering analysis of actual reliability concerns. Instead, the likely outcome is unnecessary and burdensome additional analysis and documentation that is impractical, creating confusion and uncertainty as to what the practical interpretation of impractical requirements might ultimately be.
SERC Dynamics Review Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~		

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment:		
MidAmerican Energy Company	No	a. MEC is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model variations then the steady state studies in R2.1.3.1. MEC recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. MEC believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MEC believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability.
Response: a. As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
MRO NERC	No	a. The MRO is not sure why R2.4.3.1 for sensitivities for Stability studies is a less definitive definition for load model

Organization	Question 10:	Question 10 Comments:
Standards Review Subcommittee		variations then the steady state studies in R2.1.3.1. The MRO recommends that R2.1.3.1 be changed to "Variations in Load model assumptions." b. The MRO believes R2.1.4 and R2.4.4 should be deleted because its unnecessary to make a requirement of sensitivities that an entity chooses to do above and beyond the requirements in R2.1.3 and R2.4.3. If the SDT chooses not to delete these requirements, then MRO believes that R2.1.4 should be a subrequirement of R2.1.3 and R2.4.4 should be made a subrequirement of R2.4.3. The responsible entity should be allowed to select the appropriate sensitivity that should be performed. This is especially necessary given the need to perform each of these sensitivity analyses for six situations each year: peak and off-peak for two short-term years and one long-term year. Even with the requirement for one sensitivity for each case that amounts to six additional sets of analysis for steady-state and six for stability. c. For R2.1.4, we suspect that these analysis are similar to extreme event contingencies and do not have specific performance requirements. We would also like some explanation of what and how to provide the technical rationale for why each condition was or was not used.

Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable".

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

b. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. In addition, Requirements R2.1.4 and R2.4.4 have been deleted.

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

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

c. Requirement R2.1.4 has been deleted.

Organization	Question 10:	Question 10 Comments:
Austin Energy	No	Appropriate sensitivity analysis should be determined by the Transmission Planner and/or the Planning Coordinator (ISO or RTO) and not made a routine requirement. Therefore, R2.1.3 should be deleted.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	No	These requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. In general we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. The standard should not include an enumerated list of required sensitivities Engineering judgment needs to be permitted.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Midwest ISO	No	This reminds us of Category D from original table--requiring us to study something but take no action. Sensitivities are not appropriate nor effective in a planning world in which you require an array of sensitivity studies but require no action will be taken. While running sensitivities enables us to better understand system limits, why have it as a requirement if there is no action plan obligation.
Response: The requirement was added to ensure that the entities do run certain variances that would stress the System. Requirement R2 requires that such studies are documented as part of the Planning Assessment. The entity is to determine the risk associated with not modifying the Corrective Action Plan to consider these studies. The documentation puts the entity on record as stating that the variance was considered but may or may not have been incorporated in the Plan makes the entity liable for its decision.		

Organization	Question 10:	Question 10 Comments:
Tri-State Generation and Transmission Association, Inc.	No	We appreciate the extra detail describing sensitivity cases, but do not think it is reasonable to require explanations of why each condition suggested in R2.1.3.1-R2.1.3.7 was or was not studied. It should be sufficient that sensitivity studies are considered appropriate by the individual utility. R2.1.4 should be demoted to R2.1.3.8 (and the "shall include rationale" clause removed).
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. The SDT believes that documentation of why a sensitivity was selected for study should be provided. Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Lakeland Electric	No	R2.1.3.1 requires other than peak sensitivity studies while R2.1.2 requires Off peak studies. Recommend further defining of R2.1.2 to specific load level or points on forecast demand curves to eliminate any overlap between two requirements.
Response: The SDT has used the defined term "Off-Peak" and believes that this is sufficient.		
Southern Company Transmission	No	R 2.1.3 One should only have to explain why sensitivity was performed, not why it was not performed. In general we believe that breaking these requirements into specific sub requirements focusing on specific sensitivities is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no list of sensitivities enumerated as subrequirements. Engineering judgment needs to be permitted. A specific proposal for R2.1.3 which addresses the above concerns is provided as follows:R2.1.3. For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) shall be run and documented that stress the System to reflect one or more conditions such as higher or lower Load than forecasted with variability of Load/demand and Load power factors due to season, weather, or time of day; modification of expected transfers; unavailability of long lead time Facilities; variability and outages of reactive resources; generation additions, retirements, or other dispatch scenarios; decreased effectiveness of controllable Loads and Demand Side Management; modification of planned Transmission outages. Document why each sensitivity was selected.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement you reference. In addition, Requirements R2.1.3 and R2.4.3 have been		

Organization	Question 10:	Question 10 Comments:
revised to make it clear that "~~s~~ensitivity 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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Brazos Electric Power Cooperative, Inc.	No	2.1.3 should have been left alone. We have a real problem with the addition of 'technical' and documenting why things were NOT selected. We would also like to see more leeway provided to the TP and PC by adding language similar to that mentioned above such as "as deemed necessary by the TP or PC".2.1.4 should be incorporated into 2.1.3 in a similar fashion as our suggested changes for 2.4.3.
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. In addition, Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~ensitivity 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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, Requirements R2.1.4 and R2.4.4 have been deleted. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
NERC and Regional Coordination	No	The standard as worded:? Implies all tests are run for a given sensitivity the standard should be revised to read applicable testing for the applicable sensitivity.? Requires proof of negative o Why a sensitivity was not selected? Requires that expansion plans identify the impact of sensitivity o Many sensitivities may have varying impacts on an expansion plan. Suggested changes:R2.1.3 - For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that reflect one or more of the following conditions shall be incorporated into the assessment. Documentation of the

Organization	Question 10:	Question 10 Comments:
		technical rationale for why each of the conditions was selected and the portion of the assessment that included each selected sensitivity shall be supplied. R2.1.4, R2.4.3, and R2.4.4 - need to be modified accordingly. Delete R2.1.4 as it is superfluous. If a PC runs a sensitivity study and includes that analysis in its Plan, then why would NERC mandate that the PC explain why the non-mandated sensitivity study was run. If a study is required then it should be mandated. If a study is not mandated then he PC should not be held accountable for explaining the un-mandated study.R2.4.3.1 ? Variation in load model. Specific numbers should be included. R2.4.3.2 - Modification of expected transfers ? Be more specific. Firm or non-firm transfer and amount of MWR2.4.3.3 - Unavailability of long lead time Facilities. How many years out we are looking at and for how long it must be out of service.R2.4.3.4 - Variability of Reactive Source ? need to be more specific (give me MVARS). We already test this under FAC 010 for lost of shunt capacitor.R2.4.3.5 - This should already been taken into account when we do studies. So be more specific.R2.7.2 - Include a description of how results of the sensitivities selected in accordance with Requirements R2.1.3, R2.1.4, R2.4.3, and R2.4.4 impacted the list of actions developed in accordance with R2.7.1.R2.1 - Revise wording - The annual assessment of the of the NT Planning Horizon shall include: then go into the sub-bullets. The SDT must clarify exactly explicitly how many studies (in terms of numbers) must be done each planning horizon for short term and long term and how much sensitivity study for term.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities".

Also, Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run.

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

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

The SDT agrees with the commenter and has deleted Requirements R2.1.4 and R2.4.4.

The SDT did not want to be more prescriptive and provide specific details and number for variances that the entity may select because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.

Requirement R2, along with its sub-requirements, requires the sensitivities run are to be documented. Requirement R2.6 requires that the Corrective Actions be listed. The entity can add the details and further explanation of how the sensitivities were incorporated into the Plans.

Organization	Question 10:	Question 10 Comments:
Since the basis of the standard is to allow the entity to support the Planning Assessment using current and past studies, the standard cannot dictate the specific number of studies to be made. The standard does specify the current cases that must be run in Requirements R2.1.1, R2.1.2, R2.2, R2.4.1 and R2.4.2.		
IESO	No	As we commented on R2.4.3, we continue to express our disagreement to include sensitivity testing in R2.1.3 and R2.1.4. We are disappointed that despite disagreements by the majority of the commenters and their suggestions to leave sensitivity testing to the TP's and PC's discretion, the SDT continues to stipulate detailed requirements for sensitivity testing. The SDT in its summary response to comments indicates that these testing are intended as "?providing some guidance on what could be included in the sensitivity studies without being too prescriptive." If these are indeed intended as guidance rather than enforceable requirements, then they should be provided in a technical document or a reference document that supports the standard, not in the standard itself.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
North Carolina Electric Membership Corp	Yes and No	Sensitivities to base assumptions for studies are always good utility practice. But we agree with others that these may be overly prescriptive in requiring each and every one. Allow the TP and PC to select the appropriate sensitivities for the annual assessments with input from customers and affected stakeholders. We are concerned that the requirement for every sensitivity each and every year would result in excessive burden to existing PCs and TPs doing this analysis with no resulting improvement to reliability.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
E.ON U.S. Transmission Planning	Yes and No	2. R2.1.3.2 refers to modification of expected transfers as a sensitivity test. Does this include transfers across the system, such as a transfer from Cinergy to TVA?
Response: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies		

Organization	Question 10:	Question 10 Comments:
ERCOT System Planning		The sensitivity cases suggested are unnecessary and unfeasible. For example, generation additions to cases that can already meet the load under contingency conditions do not create a reliability problem as the new generator can always be turned off. On the other extreme, sensitivity analysis of possible, unknown and uncontrollable generation retirements along with the Table 1 requirements of P3 (Generator + 1) contingency analysis presents an overwhelming study and documentation burden that will not add a corresponding benefit to the study and the results would be meaningless.

Response: The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a system sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “~~s~~ensitivity 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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”.

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

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:

Organization	Question 10:	Question 10 Comments:
American Transmission Company	No	For R2.1.3, we would like further explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used. In the subrequirements, we are unsure of what is exactly meant by "variability of load demand and load power factors", "modification of expected transfers", "long lead time Facilities", and "modification of planned outages". For R2.1.4, it is unclear what specific performance requirements must be met for these other sensitivities. We would also like some explanation of what technical rationale is expected and how it should be provided as to why each condition sensitivity was or was not used.

Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances.

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

R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the~~

Organization	Question 10:	Question 10 Comments:
~~conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies. Also, Requirements R2.1.4 and R2.4.4 have been deleted.		
Duke Energy	No	Although we agree with the perceived intent of R2.1.3, we believe the wording should be revised to make it very clear that it is not necessary to perform studies to substantiate your technical rationale for choosing not to perform any particular sensitivity study. Documented engineering judgment to support the decision not to perform the particular sensitivity studies should be sufficient. Recommend renumbering R2.1.4 to R2.1.3.8 and reword as follows: Any other sensitivity, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems.
Florida Reliability Coordinating Council, inc	No	R2.1.3 and R2.1.4 as written can create issues during the compliance assessment. These requirements place the burden of justifying the inclusion / exclusion of the sensitivities on the TP or PC. Thus, only a sensitivity deem appropriate by the TP or PC and not performed can be found non-compliant. R2.1.4 can be eliminated by modifying the wording in R2.1.3 as follows:? For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, at least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the Transmission Planer and Planning Coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year.?
Response: Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
Central Maine Power Company	No	a. With respect to R2.1.3 delete "that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.

Organization	Question 10:	Question 10 Comments:
		c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ISO New England Inc.	No	a. With respect to R2.1.3 delete " that Stress the System with sensitivities". b. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required. c. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
ColumbiaGrid	Yes	We generally agree with the concept of the sensitivity analysis since this is standard practice in understanding system performance risks and the effectiveness of improvements. R2.1.4 requires explanation of performing additional sensitivities that are not listed in the R2.1.3. This would discourage entities from performing additional sensitivities. In addition, in the above example, the Transmission Planners should not have to explain why they feel that this higher level (1 in 10 year adverse weather) of load is the ?base case? condition.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The SDT agrees and has deleted R2.1.4.		
NSTAR Electric	No	1. With respect to R2.1.3 delete "that Stress the System with sensitivities".2. R2.1.3 should be revised to clarify that if a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, then additional studies of a less-stressed system are not required.3. The intention of Paragraph R2.1.4 is unclear and appears to be unnecessary; therefore, it should be removed.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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”. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with		

Organization	Question 10:	Question 10 Comments:
~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted.		
New York Independent System Operator	No	If a TP/PC conducts the studies specified in R2.1.1 and R2.1.2 with one or more of the sensitivities which stress the system in the normal course of study, we assume that fulfills the requirements of R2.1 completely, without additional studies of a less-stressed system. Is that correct?
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The standard expects that at least one more of those variances listed in Requirement R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written the standard is requiring at a minimum one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the System responds to the variances.		
Oncor Electric Delivery	Yes	Generally agree with modifications although would again stress that detailed load modeling for stability analysis may be as revealing as some of the sensitivity studies recommended in R2.1.3 if they were only run with steady state analysis.
Response: As with all planning models, assumptions must be made that the entity feels are representative of how the System will respond and perform. Models can only attempt to simulate the System based on expected conditions. The standard has been modified to explain that "an aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable". **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic		

Organization	Question 10:	Question 10 Comments:
behavior of the Load is acceptable.		
FirstEnergy Corp.	No	The requirements related to sensitivity cases as written in draft 2 are an improvement over draft 1 as they now allow flexibility in choosing sensitivities, compared to what use to be a fixed list of options. However, we do not agree with the need to document the technical rationale for why each listed condition was or was not selected. This seems to create a needless paper trail from an auditing viewpoint. If any documentation is needed, it should be limited to why the sensitivity was selected and it should not be required to indicate why others were not selected. Therefore, we suggest rewording 2.3.1 as follows: "For each of the studies described in Requirement R2.1.1 and Requirement R2.1.2, sensitivity case(s) that stress the System with sensitivities that reflect one or more of the following conditions shall be run and documentation of the technical rationale for why each of the conditions was selected shall be supplied:"R2.1.4 - This is an optional requirement and should be worked into the list of options within 2.1.3. As a stand alone requirement, what type of measure or VSL would be applicable for this requirement? We suggest re-numbering this requirement as a new 2.1.3.8 and reword it as follows: "Any other sensitivities, as deemed appropriate by the Transmission Planner or Planning Coordinator for their individual systems".R2.1.3.3 ? This requirement indicates sensitivity is needed for "Unavailability of long lead time facilities." Why is this required in a near-term planning horizon? How long is long? Doesn't the N-1-1 (Planning Event P6) test already account for this related to the outage of existing equipment which may present long lead times? Same comments apply for R2.4.3 and R2.4.4 in the stability study section.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The STD agrees. Requirements R2.1.4 and R2.4.4 have been deleted. The near-term horizon extends from one to five years. Equipment scheduled for installation in five years requires ordering today. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “~~s~~ensitivity 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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”.		
Orlando Utilities	Yes and No	I generally agree with the intent of requiring studies beyond just one load level and system condition; however I have some

Organization	Question 10:	Question 10 Comments:
Commission		specific suggestions, questions and comments. R2.1.3: As worded I have several concerns: 1. This would make any study performed that did not include sensitivities useless for performing the assessment. I recommend identify sensitivities and studies separately, with sensitivities just being smaller versions of studies. (Our usual definition is that a study demonstrates specific solutions to problems identified, whereas a sensitivity merely comments on the presence or lack of problems and how they relate to what is seen in the more formal studies. Obviously a problem found in a sensitivity not seen in a regular study receives additional focus.) 2. This would force the study to look only at the sensitivities listed rather then allow one or more of the conditions, plus additional conditions all in one run. This would force an entity to run additional studies if they wished to exceed the requirements rather then a single study that meets and exceeds the requirements. I suggest the following wording instead to still require the sensitivities, but allow flexibility in how they are performed. "R 2.1.3: At least one sensitivity shall be performed that stress the system based on one or more of the following conditions, plus any additional conditions determined by the transmission planner and planning coordinator. The Planning Assessment will also include the technical rationale for why each of the conditions was or was not selected for study that year. R.2.1.3.1- Suggest adding system growth, for example "season, weather, unpredicted system growth, or time of day". As written it does not seem to allow a study based on the long range load growth prediction being off, but instead only on a change in season, weather or time of day. R2.1.4: What was intended by using the phrase "Documentation of the technical rationale" instead of simply saying "shall include technical rationale"? I suggest dropping the "documentation of the" as this could cause confusion on an audit as to what is the difference between the "technical rationale" and "documentation of the technical rationale" unless the drafting team plans to define what "documentation of technical rationale is" other then the rationale itself.

Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "~~s~~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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances.

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

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

The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which

Organization	Question 10:	Question 10 Comments:
and how much of a variance is appropriate for its studies. Requirements R2.1.3 and R2.4.4 have been revised to remove the requirement to explain why a sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. Since these are sensitivities, any and all variances provide some level of information as to how the system responds to such variances. Requirements R2.1.4 and R2.4.4 have been deleted		
Entergy Services, Inc.	No	R2.1.3.2 - Modification of expected transfers: Modification of expected transfers infers that non-firm transmission use would be estimated based on historical data or perhaps an economic outlook. To plan the system for such non-firm use is an imprudent burden on rate payers. Economic tools are available to ascertain the benefits of system upgrades and prudently allocate the costs of such upgrades. Generation assets and the future plans of those assets is market sensitive information that could easily be extracted from such sensitivity analyses. Results of these sensitivity studies should be used to aid in reliably operating the system. They should not be a basis for constructing transmission facilities for reliability. These types of studies are aligned with the operating horizon. See also comments made above regarding 2.1.3.4 and 2.1.3.7.In general, we believe that breaking these requirements into specific sub requirements, focusing on specific sensitivities, is too prescriptive and inappropriate. It will lead to over focus on these particular issues to the detriment of system reliability. There should be no enumerated list of required sensitivities. Engineering judgment needs to be permitted. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning.
Response: Requirements R2.1.3 and R2.4.3 have been revised to make it clear that "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". The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as "sensitivities". In addition, as written, the standard is requiring at a minimum, one case run for each required current year for steady state and Stability. This translates into three cases for steady state. The entity may run as many additional cases as it deems appropriate to understand how the system responds to the variances. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		

Organization	Question 10:	Question 10 Comments:
The SDT believes that planners must consider these possible variances and reinforce the System so that when it comes to Real-time operation, the TOP will have a System sufficiently robust to operate around any of the conditions. Commenters generally agree that these are the responsibility of planning. The SDT did not want to be more prescriptive because of the huge number of possible variances that can occur. It is up to the planning entity to determine which and how much of a variance is appropriate for its studies.		
BPA Transmission Reliability Program	No	For those conditions that are "not" studied, it makes sense to explain why that particular condition was not selected. However, we do not agree with R2.1.3 that a rationale needs to be provided for why a particular sensitivity "is" selected for study. Running additional sensitivities provides a better understanding of system performance and doesn't need further justification. Requirement R2.1.4 is not needed and should be removed. It should be up to the Transmission Provider's discretion whether they run additional sensitivity studies beyond what the standard requires in R2.1.3, and it should not be necessary to justify why they chose to run them. What a sensitivity study consists of, needs further clarification. For example, if a system assessment is performed using a case with transmission paths stressed near their limits, is this considered the baseline or a sensitivity? If it is considered the baseline, would a sensitivity be required at reduced stress levels and what purpose would this serve when the original case produced the more severe system impacts? This needs further clarification.
Response: Requirements R2.1.3 and R2.4.3 have been revised to remove the requirement to explain why sensitivity was not run since it would be necessary to run the study regardless to provide proof why it was not run. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: Requirements R2.1.4 and R2.4.4 have been deleted. Requirements R2.1.3 and R2.4.3 have been revised to make it clear that “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”. The standard expects that at least one more of those variances listed in Requirements R2.1.3 and R2.4.3 that have not been integrated into the required studies are at least considered as “sensitivities”.		
City Water, Light & Power - Springfield, Illinois	Yes	

Organization	Question 10:	Question 10 Comments:
Platte River Power Authority	Yes	
BCTC	Yes	
Manitoba Hydro	Yes	
Tenaska, Inc.	Yes	
Arkansas Electric Coop. Corp.	Yes	
AEP	Yes	
LCRA TSC	Yes	
Response: Thank you for your response.		

11. In response to industry comments, the SDT modified Table 1 requirements for Planning Event P6. Planning Event P6 involves independent overlapping single contingencies (n-1-1) involving two Transmission Facilities excluding generators. This Planning Event generally correlates to P5 of the first draft and now includes shunt devices. The P6 event was also revised to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV.

Do you concur with the modifications? If not, please state why and/or suggest specific changes.

Summary Consideration:

A substantial majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving systems above as well as below 300 kV, considering the low probability of such Events.

There are concerns that this change would make it difficult for scheduling maintenance outages because the existing TPL-003-0 allows shedding of Non-Consequential Load after the next outage . However, in the proposed standard, If a facility is scheduled out of service for maintenance, the next outage would be considered a single Contingency Event, and loss of Non-Consequential Load is not permitted.

There are concerns expressed by numerous respondents that after the first single Contingency and System adjustment, curtailment of Firm Transmission Services (or firm transfers) and shedding of firm Load would not be allowed in preparation for the second Contingency. The SDT added Footnote # 10 to the end of Table 1 to reflect that Curtailment or Interruption of Firm Transmission Service in preparation for the next Contingency will be allowed. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any firm Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (Requirement R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe.

Some respondents requested that System adjustment be defined. The SDT believes that Header note 'e' and the new Footnote # 10 provides the description of the System adjustments allowed after a first Contingency Event.

There were also requests for clarification between a P1 Event, which occurred after another Facility has been out of service, for example, for scheduled maintenance, and a P6 Event, since the former will not allow loss of Non-Consequential Load, while the latter would allow it. The SDT believes that the difference between these two Events is whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). Therefore, if the Prior outage is planned or anticipated, then the next N-1 is a single Contingency Event, otherwise, it would be a P6 Event.

Concerns were also expressed that the TP and PC should have discretion on the Contingencies (for example, shunt devices) to study and analyze. One response suggests that the P6 Event to be studied should have a common reason to occur. The SDT modified Requirement R3.3 (now R3.4) to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the area of study, and they can choose not to study loss of shunt devices, or those P6 Events that do not have a common reason to occur, if these are less severe than the Events studied.

Some responses suggest that there should be a specific limit to the amount of Load loss allowed. While the SDT does not disagree with having some specific limits below which Load loss would be allowed, arriving at such an amount may be too case-specific and too prescriptive for a Continent-wide Standard.

One response disagrees that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV. The SDT believes that an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than outage of two single lines.

As a result of industry comments, the following requirements were changed:

R3.3.3 (now R3.4) Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~includ~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Footnote #10 – 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 be considered.

Organization	Question 11:	Question 11 Comments:
Dominion - Electric Transmission Planning	No	For Bulk Electric System (BES) Elements out of Service above 300 kV, interruption of Firm Transmission Service and Non-Consequential Load Loss should not be allowed. We favor the language proposed in the previous draft.
ITC Holdings: ITC, METC, ITC Midwest	No	Allowing load loss for shutdown plus contingency might seriously jeopardize maintenance outages when you actually encounter this situation in real-time. It's easy to say these things in the ?planning horizon? but it might be politically unacceptable for "real-time". This is particularly true for higher voltage systems above 300kV. We understand that there could be "load-pocket" situations at lower voltages where this might be allowed but EHV systems are back-bone systems. This would set a bad precedent if allowed.
Lafayette Utilities	No	Lafayette does not agree that the loss of Non-Consequential Load should be permitted as a corrective action. See also

Organization	Question 11:	Question 11 Comments:
System		paragraph (b) in response to Question 15.
Arkansas Electric Coop. Corp.	No	Non-Consequential Load Loss should not be allowed. See comments to question 7.
Response: Thank you for your comments but the majority of the industry respondents agree with the revision to permit loss of Non-Consequential Load to meet performance requirements for P6 Events involving Systems above as well as below 300 kV considering the low probability of such Events.		
City Water, Light & Power - Springfield, Illinois	Yes and No	Shunt devices should only need to be included in contingency analysis at the discretion of the TP or PC.
CenterPoint Energy and CPS Energy	No	We believe P6 should be deleted. As noted earlier, we believe credible multiple contingencies should be studied as planning events, with incredible multiple contingencies possibly considered as extreme events. If P6 is retained, we believe loss of shunt devices should not be studied and believes the ability to systematically study the contingency loss of every individual switched shunt device is not supported by commercially available PTI software because up to this point it has not generally been recognized as a necessary or desirable analysis to perform. Also, if P6 is retained, we believe loss of Non-Consequential Load should be permitted at any voltage level for this type of extreme event.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingencies most suited to the study area, including whether to include shunt devices in the analyses. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
Progress Energy Carolinas	No	While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to ensure that this is clearly understood. One suggestion would be to include the following footnote to P6 in both the Steady State and Stability Tables.? Foot note: Interruption of firm transmission service and/or non-consequential load loss is allowed after the first event as a System adjustment to prepare

Organization	Question 11:	Question 11 Comments:
		for and meet the requirements of the second event. See also our related response to question 15.
Gainesville Regional Utilities	Yes and No	I believe some clarification is needed to specify that you can or can not curtail firm transmission service prior to the next event, because as written it could lead to compliance audit issues. I don't believe the intend of order 693 was to cause a need for utilities to be exposed to large cost increases for their customers while very little to no improvement in reliability is provided as it deals with very low probability conditions which would yield no increase in transfer capability.
JEA	Yes and No	JEA agrees with the changes on the surface, but still does not agree with the concept that it can not curtail Firm Transmission Service after the first N-1 event in preparation for the second N-1 event. JEA's existing Firm Transmission Service customers understand the need to maintain these existing transmission loading relief procedures in order to maintain security of the BES. The only JEA system element that causes this concern has a very high availability and would have a very costly infrastructure improvement to meet this requirement resulting in all of JEA's Firm Transmission Service Customers experiencing increased service cost or in the worst case having their service opportunities permanently curtailed.
Florida Power and Light	No	The P6 Planning Event is not clearly defined. It appears that the Initial System Condition is the Planning Event of P1, with the ?System Adjustments? allowed under P1 to keep facilities within the applicable ratings. R3.5.3. requires that a sustainable, stable, operating condition is maintained. This does not state prepared for the next contingency?. Given FERC's interpretation of TPL-002-0 Category B (see paragraphs below for excerpts from Order 693) that the system is not required to be able to withstand another N-1 contingency, the proposed new standard appears to require that this state be "sustained" indefinitely after a P1 event, or until the P6 Event, which is loss of the second element, with no mention of the time duration between the initial system condition and the event. The performance criteria for a P1 event can be met as long as it does not contemplate another event that would change the event to a P6 event. However, a P6 event is a TPL-003-0 Category C event which must contemplate a second contingency after the first. The existing TPL standards accomplished this with footnote b) in the Tables for all of the TPL standards, allowing system adjustments including curtailment of contracted firm transfers to prepare for the next contingency. Since FERC clearly states that this is not a requirement under TPL-002-0, but that it is addressed in TPL-003-0, they directed the ERO to modify the footnote for TPL-002-0. In TPL-003-0 the Category C3 event refers to a "Category B contingency, manual system adjustments, followed by another Category B contingency", however since the footnote for Category B contained the "To prepare for the next contingency?." language, and it is contained in the Table for TPL-003-0, that language must apply to the C3 event. Further, in Order 693, on TPL-003-0, FERC (1) did not direct the ERO to modify the same footnote which is contained in TPL-003-0, (2) recognizes that these are low probability events, and (3) stated that it "does not intend to recommend action on this issue [the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets] at

Organization	Question 11:	Question 11 Comments:
		this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.? The SDT has inappropriately applied the direction of FERC on TPL-002-0 to the P6 event (which is similar to TPL-003-0 C3) without regard to its implications on the industry, the ratepayers, or even its own standards, as the impact of the team's interpretation would require changes in the methods of determining TTC's, ATC's, and SOL's. The additional costs (both monetary and intangible) incurred by ratepayers for no gain in the ability to transfer firm electric power, far outweigh any gain in reliability benefits for these low probability events. Just to provide one example to illustrate this point, if the SDT's current interpretation for a P6 event is not modified, FPL would have to spend in excess of $ 1 Billion dollars, in order to meet this performance criteria for 500 kV facilities, for an event with a probability of less than 0.07 per hundred mile-years (based on FPL's 500 kV facilities), which would be passed on to its ratepayers. There are many other examples on the FPL system, as well as other systems. This interpretation is fatally flawed and makes no sense from a reliability or cost perspective, not to mention the intangible impacts of siting, right-of-way acquisition, EMF, NIMBY, etc. Further, assuming the SDT interpretation, how could one justify the need before state commissions, and exercise eminent domain in the courts to take someone's land for right-of-way, a process that could take as long as 8-10 years, for minimal increase in reliability, and no increase in transfer capability. In order to assist the SDT, these paragraphs are included with references to FERC Order 693, to show that it has misinterpreted Order 693. The following captions stated below should help clarify this point. Order 693 states: P.1788 ?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.? Therefore, the end state of P1 is not a ?secure? state, but a ?normal operating state?, as stated in P. 1796 ?The Commission, therefore, directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? These two determinations by FERC together show that their interpretation of normal operating state is not the secure, ready for the next contingency state, rather, it is the state in which the performance criteria have been met for that planning event. With regard to the FERC direction of Order 693 on TPL-003 and ?the appropriateness and value of including the ability of the system to withstand two simultaneous Category B contingencies for major load pockets?, FERC states in P. 1824, ?Many commenters indicated that this was a very low probability event and the costs for addressing such an event would be significant. As a result, EEI states that a dialogue must first be initiated within the industry and with state public utility commissions to identify such load pockets, to target the required potentially significant transmission investments and to develop plans for allocating the costs of such investments. In light of these comments, the Commission does not intend to recommend action on this issue at this time and, instead, directs the ERO to consider the comments in possible future revisions to the Reliability Standard.?FPL agrees with the increased performance requirement for the P3 multiple contingency event that assumes the loss of a generator as the first contingency. Firm transfers should not depend upon specific generators being on line, however firm transfers must depend upon transmission lines being in-service.
SERC Dynamics	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service

Organization	Question 11:	Question 11 Comments:
Review Subcommittee		and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as modification or as a footnote for the P6 portion of the table as follows:Foot note: Interruption of firm transmission service and non-consequential load loss should be allowed after the first event as a system adjustment to prepare for the second event and meet the requirements following the second event.See our related response to question 15.
Southern Company Transmission	Yes and No	The requirements are more practical now. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Duke Energy	Yes	The changes are more practical. If two or more 500kV lines are lost, it makes complete sense to allow loss of non-consequential load so long as cascading outages are not triggered.? While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (defined as initial system condition in the table), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event.? We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement above be included as a modification or as a footnote for the P6 portion of the Steady State and Stability tables as follows: "For P6 multiple contingency events, Transmission configuration changes and redispatch of generation are allowed provided that all Facilities shall be operating within their Facility Ratings and within their thermal and voltage limits. Permissible Transmission configuration changes include dropping of load and firm transfers needed to prepare for the second contingency. See our related response to question 15.
SERC Reliability Review Subcommittee and Planning Standards	Yes	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3. While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency, these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the

Organization	Question 11:	Question 11 Comments:
Subcommittee		first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event.
Orlando Utilities Commission	Yes and No	As written the standard does not seem to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an N-1-1, however that conflicts with the teams statements on the recent national call. If the intent is to forbid the adjustment of firm transfers and non-consequential load in preparation for the second part of an n-1-1 that needs to be made explicitly clear in the standard. This is especially important since one of the current understandings of the standards relating to Transmission Planning and System Operating Limits clearly allow such adjustments, and to not make it clear is building a compliance trap for the unwary. While I do not support the creation of this n-1-1 threshold if it is going to be established it needs to be abundantly clear.
Entergy Services, Inc.	Yes and No	Since Event P6 is essentially a sub-set of the existing Category C.3 Contingency events, we support these modifications which make the system performance requirements for P6 consistent with what exist today for Category C.3.While we agree interruption of firm transmission service and non-consequential load loss should not be allowed to meet the planning requirements for the first system contingency (to get loadings back within normal ratings), these system adjustments should be allowed to prepare for the second event so that the system will meet the requirements following the second event. We recommend that clarifying changes be made to incorporate this concept. We recommend that the statement below be included as modification or as a footnote for the P6 portion of the table as follows: Interruption of firm transmission service and non-consequential load loss are allowed after the first event as a system adjustment to prepare for the second event in order to meet the requirements following the second event. As the requirement is now implemented in the table, transmission service would need to be made available only if they can be accommodated for N-2 events. This would place these services on equal footing from a reliability perspective but would virtually eliminate the firm transmission market.
Response: Footnote #10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Nonetheless, the SDT has provided an exception (R2.6.4) to address those situations, which may arise that are beyond the control of the Transmission Planner or Planning Coordinator, and, which can prevent the implementation of the relevant Corrective Action Plan in the required timeframe. **Footnote #10** – 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 be considered.		
Transmission	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above

Organization	Question 11:	Question 11 Comments:
Agency of Northern California		300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Pacific Gas and Electric Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Public Service Company of New Mexico	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Puget Sound Energy, Inc.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power

Organization	Question 11:	Question 11 Comments:
		transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Idaho Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SMUD	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Sierra Pacific Power Company / Nevada Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1

Organization	Question 11:	Question 11 Comments:
		and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Black Hills Corporation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
SRP	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tucson Electric Power Company	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow

Organization	Question 11:	Question 11 Comments:
		the Non-consequential Load Loss, while the latter would prohibit it.
Modesto Irrigation District	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Tri-State G&T	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
ColumbiaGrid	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.

Organization	Question 11:	Question 11 Comments:
Southern California Edison	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
Alberta Electric System Operator	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the next N-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
US Bureau of Reclamation	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV. However, we are concerned that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers would not be allowed as part of system adjustment in preparation for the nextN-1. Allowing curtailment of transmission service or firm transfers for such system adjustments should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1, or transmission facilities, which would have otherwise been unnecessary, would have to be built. Either would adversely impact customers. We also have questions on Event P6 in both Performance Tables 1 and 2: We would like some clarification on the overlapping single contingencies as denoted in Event P6 (N-1-1), and one where a single contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (N-1). The former would allow the Non-consequential Load Loss, while the latter would prohibit it.
BPA Transmission	Yes and No	We agree with the revision to permit the loss of Non-Consequential Load to meet performance requirements for Systems above 300 kV. However, a better definition is needed for "system adjustments". For example, are curtailments permitted as

<table>
<tr><th>Organization</th><th>Question 11:</th><th>Question 11 Comments:</th></tr>
<tr><td>Reliability Program</td><td></td><td>part of "system adjustments"? Within category P6, there needs to be a common reason for the overlapping outage to occur, such as lines on a common tower, and the appropriate reasons need to be clearly identified in the requirements. In general, we believe that performance category P6 should be part of the Operating Standards rather than the Planning Standards. For these types of events, it is the responsibility of Operations to determine the necessary system adjustments to prepare for the next contingency within the operating horizon prior to year one as defined in the Planning Standards. Therefore, the performance requirements for this category of contingencies, do not belong in the Planning Standards.</td></tr>
<tr><td colspan="3">Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency.

Footnote #10 – 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 be considered.

Regarding the difference between overlapping single Contingencies as denoted in Event P6 (N-1-1), and one where a single Contingency, say Event P1 (N-1), follows a prior "planned" outage of a Facility (i.e., N-1), the difference would be whether the prior outage was planned (such as maintenance) or anticipated (such as extended outage). If the Prior outage is planned or anticipated, then the next N-1 is a P1 Event, otherwise, it is a P6 Event.</td></tr>
<tr><td>Progress Energy Florida, Inc.</td><td>No</td><td>PEF is pleased that between the 1st and 2nd drafts, the "no" was changed to "yes" concerning allowance of curtailment of Firm Transmission Service or curtailment of Non-Consequential Load for Event P6. PEF has significant concerns, however, regarding the issue of "System Adjustments" associated with P6 and P6's direct association with P1, and thus must check "no" on this Question despite the improvements that have been made. A major misstep has been made with regard to development of P6. Every P1 event is by default the first half of a P6 event. Given that fact, PEF sees several concerns with this issue. First, for P1 events, neither curtailment of Firm Transmission Service nor curtailment of Non-Consequential Load are allowed, regardless of voltage. Both are allowed, however, for a P6 event. In order for the two events to not contradict each other, the conclusion that must be reached is that curtailment of Firm Transmission Service and curtailment of Non-Consequential Load are not allowed as part of System Adjustments, i.e. they are not allowed in between the two steps of P6, only after the 2nd step of P6 (Note: this is not clear partly due to the fact that the term "System Adjustments" is not defined anywhere in the Standard, and PEF therefore requests that the SDT define the term, and that the term should include the allowance of curtailment of Firm Transmission Service and the loss of Non-Consequential Load). PEF has two very serious concerns with that conclusion:

a) FERC in its Order 693 stated that the BES is not required to have to withstand another N-1 contingency. Specifically, in Paragraph 1788 of Order 693 FERC states that ?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.? Thus FERC clearly made a distinction between N-1 events for which a 2nd N-1 event never happens and N-1-1 events. The SDT, however, has</td></tr>
</table>

Organization	Question 11:	Question 11 Comments:
		not written the draft TPL Standard in such a way that Transmission Owners can reasonably and fairly plan for the 2nd N-1 event as TPL-003-0 has done. b) PEF has several 1st N-1 events on their 500 kV system for which "System Adjustments" are necessarily going to have to include either the curtailment of Firm Transmission Service or the curtailment of Non-Consequential Load in order to prepare for the 2nd N-1 event. The draft TPL Standard, while far from definitive on this matter, appears to allow neither as part of System Adjustments. PEF will thus be forced to i) construct redundant 500 kV facilities, at a cost to our ratepayers that will doubtless run into the range of billions of dollars, or ii) significantly reduce the posted levels of ATC/TTC of the various transmission paths available. Option (ii) is not a better option than option (i), for two main reasons: reducing ATC/TTC essentially puts marketing entities out of business, and forces utilities to build more generation sites to compensate for the loss of energy brought in using the previously higher ATC values. Either option results in prohibitively high costs to be passed on to the ratepayers for no measurable increase in BES reliability. This discussion also brings up additional concerns that include the lack of consideration of State government jurisdiction, the lack of public involvement, and ultimately, the lack of sufficient reason to construct such redundancy. PEF has never had a 500 kV N-1-1 event on its system. For this draft Standard to require redundancy projects costing billions of dollars for events that to date have never occurred is preposterous (note: additional comments concerning public outreach, no State government involvement, etc., are contained in the response to Question 15).
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for a single Contingency Event. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. Header note 'e' provides the System adjustments allowed after a first Contingency Event. **Header note 'e'** -- <u>For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.</u> **Footnote #10** – <u>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 be considered.</u>		
Ameren	No	Please clarify that the shunt devices to be considered for outage are those that are directly connected to the transmission system. For the P6 events involving a transmission facility and a shunt device, local voltage instability issues may result in dropping of load in the vicinity of the outaged facilities, but the concern should be that the load dropped is not wide-spread. The words "Voltage instability" should be removed from Header Note 3 of Table 1 so that it becomes "Cascading outages and uncontrolled islanding shall not occur."

Organization	Question 11:	Question 11 Comments:

Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

However, “voltage instability” has not been removed from the Header Note 3 (now Note a) because voltage instability in a local area can spread to the rest of the System if not arrested in time, and a planning analysis is needed to ascertain if there is a voltage stability problem, and, if so, the corrective actions needed.

Organization	Question 11:	Question 11 Comments:
Exelon Transmission Planning	No	We do not agree that the requirement should be so much more severe for an internal breaker fault as opposed to two single line outages for elements over 300 kV.

Response: An internal breaker fault is a single event covered in FERC Order 693. In addition, an internal breaker fault would remove from service all Facilities connecting to the faulted breaker simultaneously, which would likely be more severe than the outage of two single lines.

Organization	Question 11:	Question 11 Comments:
MidAmerican Energy Company	No	MEC suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.
MRO NERC Standards Review Subcommittee	No	The MRO suggests that there be more explanation of what system adjustments are permitted. There should be some specific limit like 100MW below which load loss is allowed. Otherwise, very high cost solutions will be required for very low probability events.

Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. While the SDT does not disagree with having some specific limits below which load loss would be allowed, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard.

Footnote #10 – 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 be considered.

Organization	Question 11:	Question 11 Comments:
Austin Energy	No	It should be left to the Transmission Planner and/or Planning Coordinator (ISO or RTO) to select the credible multiple contingencies to be studied as planning events. Therefore P6 should be deleted.
Brazos Electric Power Cooperative, Inc.	No	P6 should be incorporated back into P5. Up to this point, studying all shunt devices has not been considered to have a significant impact on the BES. In addition these are picked up when studying other contingencies. Certain type devices should be reviewed individually, FACTS devices, etc? but this should be at the discretion of the TP or PC. Currently adding shunt devices as a category would require modification to case data or software to be able to automatically run through them all and we are not convinced this is worth the effort.
Response: Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the Events studied. Therefore, P6 is not deleted. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
AEP	Yes	Table 1 does not specify a maximum amount of allowable non-consequential load loss for those categories (including P6) that have a "Yes" listed under the "Non-Consequential Load Loss Allowed" (last) column. See load loss definition under Attachment D of PJM Manual 14B for an example of a maximum amount specification.
Response: While the SDT does not disagree with having some specific maximum amount of allowable Non-Consequential Load loss for these events, arriving at such an amount may be too case-specific and too descriptive for a Continent-wide Standard		
ERCOT System Planning	No	The former P5 of the first draft only required transmission circuits of 300 kV and above to be simulated out of service followed by loss of transmission circuit or transformer. P6 of the second draft requires all BES (100 kV and above) transmission circuits, transformers, dc lines, and shunt devices in combination of another BES circuit, transformer, dc line, and shunt device. The number of contingencies that have to be simulated increased dramatically to an impractical level and would require days of uninterrupted computer run time to complete. This, in combination with other contingencies and sensitivities required in this draft of the standard, is not feasible for large entities. ERCOT recommends that this planning event P6 retain the verbiage regarding transmission lines and transformer low side windings above 300kV.
Response: The previous draft P5 set requirements for N-1-1 300 kV and above; P8 sets requirements for N-1-1 below 300 kV. P6 in this draft combines both P5 and P8 from the previous draft. So, the work load for both drafts would be the same. In addition, Requirement R3.3.3 (now Requirement R3.4) was modified to allow the PC and TP to determine the single and multiple Contingencies to be included in the planning analyses. This would give the TP and the PC the discretion		

<table>
<tr><th>Organization</th><th>Question 11:</th><th>Question 11 Comments:</th></tr>
<tr><td colspan="3">to study the Contingency most suited to the study area, and can choose not to study P6 Events if they are less severe than the events studied.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance~~ ~~not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.</td></tr>
<tr><td>American Transmission Company</td><td>Yes</td><td>We suggest that there be more explanation of what system adjustments are permitted. We understand that the revised P6 allows loss of Non-Consequential Load for Systems below 300 kV as well.</td></tr>
<tr><td colspan="3">**Response:** Header note 'e' provides the System adjustments allowed after a first Contingency Event. In addition, Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of firm Transmission Service will be allowed in preparation for the next Contingency.

Header note 'e' -- For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Footnote #10 – 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 be considered.</td></tr>
<tr><td>Florida Reliability Coordinating Council, inc</td><td>No</td><td>For P6 events (and all other events that allow system adjustments after the loss of a transmission device), this draft does not clearly define when the requirements in the columns marked as ?Interruption of Firm Transmission Service? or ?Non-consequential Load Loss Allowed? apply. The SDT should clearly state that the requirements in these columns are only applicable after the Event occurs from the Initial System Condition. In addition, the SDT should make it clear whether Interruption of Firm Transmission Service and Non-consequential Load Loss is allowed in preparation for the 2nd Event. On the NERC conference call for the 2nd draft, the SDT chair indicated that Interruption of Firm Transmission Service and Non-consequential Load Loss is not acceptable in preparation for the next event. In Order 693, Para. 1788 - Para. 1796, FERC distinguished between ?preparing for the next contingency? and returning to a system normal state. The SDT removed the allowance that was made in footnote c of TPL-003-0 to ?To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? (emphasis added) for Category C3 events (now P6 for facilities greater than 300kV). This change in the standard is not directed by the FERC Order 693 and is not a reliability improvement that is cost justified. Forced outage rates for equipment greater than 300kV is very low and the impact on markets is very large. Many utilities have granted long term transmission service to entities with the expectation that the service can be curtailed if required in preparation for the next event. If this is not allowed, entities</td></tr>
</table>

Organization	Question 11:	Question 11 Comments:
		within FRCC will have to greatly reduce the long term firm imports into FRCC or construct additional EHV transmission lines from a location well into Georgia down to a point in the southeastern portion of FRCC. While an in-depth cost has not been completed for a project of this size in many years, it is reasonable to expect that a cost in excess of $1.5 - $2.0 Billion. This investment will only slightly increase the amount of firm imports into FRCC (and replace the imports allowed before this change) for an event that may only occur only once every 20+ years. If this event happens, the Transmission Owners will re-dispatch their own generation to curtail their transactions in addition to curtailing the firm transmission service of others, per their OATT. The SDT should clearly state for these Planning Events, all system adjustments including Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable in preparation for the second Event where system adjustments are allowed between events.
Response: The SDT believes that Table 1 is clear that the events occur from P0 as the starting condition. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – 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 be considered.		
FirstEnergy Corp.	Yes	We agree with the change that now permits the loss of Non-Consequential Load for N-1-1 to meet performance requirements regardless of the voltage level studied. It is well understood that following a single contingency (N-1) that no Non-Consequential Load loss or interruption of Firm Transmission service is permitted. The SDT needs to clarify for industry if interruption of Firm Transfers is permitted pre-contingency to prepare for the 2nd (over-lapping) contingency. This is presently permissible in the existing TPL standards as Table 1 footnote 'b' reads ?? To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.?
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. **Footnote #10** – 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		

Organization	Question 11:	Question 11 Comments:
in those regions must be considered.		
PPL EnergyPlus	Yes	
NPCC	Yes	
Northeast Utilities	Yes	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
TVA System Planning	Yes	
Platte River Power Authority	Yes	
BCTC	Yes	
National Grid	Yes	
Tenaska, Inc.	Yes	
OPUC	Yes	
PacifiCorp	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.
Hydro-Quebec TransEnergie (HQT)	Yes	
Arizona Public Service Co.	Yes	We agree with revising P6 to permit loss of Non-Consequential Load to meet performance requirements for Systems above 300kV.

Organization	Question 11:	Question 11 Comments:
Midwest ISO	Yes	
Tri-State Generation and Transmission Association, Inc.	Yes	
Lakeland Electric	Yes	
LCRA TSC	Yes	
NERC and Regional Coordination	Yes	
North Carolina Electric Membership Corp	Yes	
E.ON U.S. Transmission Planning	Yes	
Central Maine Power Company	Yes	
NSTAR Electric	Yes	

Organization	Question 11:	Question 11 Comments:
New York Independent System Operator	Yes	
Oncor Electric Delivery	Yes	NA
ISO New England Inc.	Yes	
Manitoba Hydro	Yes	Considering the very low probability of such an event (based on industry data), Manitoba Hydro agrees that Interruption of Firm Transmission Service and Non-consequential Load Loss is acceptable.
Los Angeles Department of Water and Power	Yes	yes, only because there is no discrimination among different and arbitrary voltage classes.
IESO	Yes	We concur with the need to test N-1-1 contingencies involving transmission facilities allowing interruptions to firm transmission services and non-consequential load loss to meet performance requirements, for any voltage levels as long as adverse reliability impacts on the BES are exhibited.
Response: Thank you for your response.		

12. Comments from some entities received from the posting of the 1st draft standard indicated that significant additional costs will be required to meet the proposed requirements and performance tables. Commenters also indicated that it would take several years to install the additional facilities needed to meet the change in requirements. The SDT has attempted to adjust and clarify the proposed requirements and performance in light of these initial comments; however, the SDT needs more specific information on these concerns so that it can put the proposed requirements in perspective and make more adjustments as appropriate. Questions 12, 13 & 14 address these concerns.

What do you estimate will be your additional approximate costs, if any, to support the proposed requirements and performance tables over and above what you are currently doing for the following: Analysis:

One time cost to supplement past study portfolio and analyze the supplemental studies (depending on the extent of supplemental work needed, this may be an accumulated cost over more than one year):

How many years do you estimate that it will take to complete supplemental studies and associated analysis?

On-going additional cost for expanded studies and analysis:

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Dominion - Electric Transmission Planning	It is extremely difficult, if not impossible, to accurately determine the costs required to perform supplemental studies in order to become compliant with these proposed standards. It will take time to just become familiar with the proposed changes as well as developing the necessary documentation to show compliance. What is obvious is that increased staffing levels will be required to perform the assessments. Furthermore, it will take significant time to become fully compliant. Therefore, a grace	As stated above, this is difficult to predict but a grace period of 2 to 3 years should be considered.	At this point we are estimating at least 2 to 3 additional resources may be required to perform the additional studies on an ongoing basis. For Dominion, three (3) additional engineers to perform this analysis is approximately $500,000 per year (including benefits and overheads).

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	period of 2 to 3 years should be granted in order to perform the required assessments and become compliant.		
NPCC	NPCC Participating Members believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables. However, the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time, and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in the standard, could have a drastic effect on the extent to which this additional analysis is conducted and the associated costs.		
TVA System Planning	One component of these costs is based on modification to the load flow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the proposed standards. Also, man-power to perform the extra analysis was considered. Additional man-power of 5 engineers (2 years) would	The majority of the time would be spent modifying the load flow database so that the new planning event simulations could be analyzed. ? Time duration estimate of 2 years would be required.	Additional man-power of 4 engineers at costs of $400,000 per year would be required.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	be required at cost of $1,000,000		
Progress Energy Carolinas	$150,000	3 Years	$50,000/year
BCTC	We estimate an initial one time cost of up to $50,000 for BCTC planners to become familiar with the new format and requirements of the standards and make changes to their assessment process. In addition, additional study costs for sensitivity studies (many stability studies) may cost an additional $50,000. Many segments of the BCTC system are stability limited and we have significant experience with the needs and timelines for doing stability studies. Stability studies identify the need for RAS for multiple contingencies, which is fairly short lead time. We are currently satisfied with the amount of stability studies we do for the near and long term planning horizons. We do not need to do sensitivity studies. We do not expect any significant additional costs for studying Extreme Events because most of the wide area events listed are not applicable to the BCTC system.	1 Year	The additional cost could be from $50,000 to $100,000 per year. We will incur additional study costs for sensitivity studies and expect additional planning administration costs for reconciling between reinforcements required to meet the CLL/NCLL definitions and P3 requirements vs. what we actually propose as doable projects.
Manitoba Hydro	$500,000	2 to 3 person years years	$300,000
Los Angeles Department of Water and Power	I do not object to added studies serving useful purposes; however, duplicative studies are a waste of resources. Mixing operating studies and requiring such studies in the planning of future system shows a confused perspective on the	Please be more specific as to what additional studies are being referred here.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	purpose of planning studies verses operating studies.		
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore costs can be speculated to be incrementally hundreds of thousands per year.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	If the new requirements are included in the normal study cycle and the costs are the incremental costs required by additional study requirements, then the annual costs will be less than the first year costs, but we still will need additional staffing, which will cost hundreds of thousands per year. In addition to cost, there is a significant concern over whether or not the labor market can provide enough qualified staff to complete the required work.
Pacific Gas and Electric Co.	We expect supplemental studies to be needed for the entire 500 kV system and most of the 230 kV system. We estimate the one time cost for supplemental studies to be around $100,000.	Assuming that the supplemental studies would be added to the on-going work, we estimate the time to complete the supplemental studies to be about 2 to 3 years.	We estimate that the additional cost for the expanded studies and analysis would be about $50,000/year.
Gainesville Regional Utilities	$50,000. I don't feel this is needed for smaller utilities.	3 years. Again, I don't feel this is needed for smaller utilities.	$60,000. Again, I don't feel this is needed for smaller utilities.
JEA	$80,000 per year.	3 years	$80,000 per year.
PacifiCorp	$500,000 (approx)	three years	$250,000
Puget Sound Energy, Inc.	$1,000,000 for the STD in its current form. The recovery of firm transmission following N-1 will be the largest cost for PSE	10 years.	$300,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	important.	important.	important.
Idaho Power Company	Appx $50k	2 to 3 years	Appx $50k
SMUD		Three study cycles would be my guess. Related matters: Since the definition for “Year One” allows for the start of each assessment to be up to 18 month from the “completion” of the previous Planning Assessment, using the term ?annual?, “annually” in the definition and in various sections of the standard is confusing. An alternate word or dropping the words annual/annually would make more sense. What is considered as “completion” of an assessment (in definition of Year One)?	
Hydro-Québec TransÉnergie (HQT)	HQT believe some additional cost for analysis and study may be required in order to meet the final requirements of the standard and the associated performance tables, however the ability to accurately estimate the costs of these studies, how long the analysis may take and how much additional effort may need to be made to compile the documentation is not possible at this time. Many believe posing this question is premature and cannot be quantified at this time and it may hold questionable value without a better understanding of the complete final requirements of the standard. Many believed that the sensitivity language, although currently being performed to some extent within NPCC, that now appears in		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	the standard, could have a drastic affect on the extent to which this additional analysis is conducted and the associated costs		
Progress Energy Florida, Inc.	Given that a) PEF has never performed analysis to the extent that the draft TPL Standard is requiring and b) the draft is going through an iterative process and is at present considered a "moving target", a reasonably accurate estimate, or even a wild guess, cannot be provided for this answer. Having said that, it can be reasonably said that any estimate that could safely claim a reasonable degree of accuracy would require analysis performed full-time by several individuals over a period of several months (or possibly a period greater than one year). Just the cost of the assessment analysis alone would present an O&M challenge to PEF's Transmission department.	PEF has assessed this question and determined that any period of time less than 10 years would be inadequate to assess the supplemental nature of the requirements of the draft TPL Standard, to say nothing of the time required to construct the required facilities.	PEF, again stating that this cannot be considered an accurate estimate for the reasons stated in 12a, would estimate the burdened labor cost to perform such supplemental analysis on an ongoing basis to be at least $1M annually.
Sierra Pacific Power Comapny / Nevada Power Company	$400,000	2 Man Years	$250,000/year
Lafayette Utilities System	Lafayette has not analyzed in any detail the resource requirements addressed in this question. Based on available information, we estimate that supplementing existing studies would require at least 1 FTE familiar with stability analysis to be able to complete this portion of TPL. The new steady-state analysis will require the addition of 1 FTE to be able to complete the additional P5-P7	See response to part 1 of Question 12.	See response to part 1 of Question 12.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	requirements. These will be ongoing expenses whether accomplished by hiring new staff or relying on external service providers.		
Arizona Public Service Co.	Two person-year.	2-years.	one person year.
Ameren	One component of cost is to model in more detail all straight busses and bus-tie breakers at all transmission voltage levels. Contingency scenarios would also need to be developed and/or modified to correspond with the new powerflow models. The sensitivities presently specified will greatly increase the cost and time needed for updating all plant stability studies.	One-time costs to provide additional modeling detail and modify and test the revised contingency lists would be approximately 1 man-month or about $8000. Updating all plant stability studies would take approximately 5 man-years, at an estimated cost of approximately $500,000 (including benefits). Given existing regional requirements to complete the annual assessment by July 1 of the calendar year, additional staffing would likely be needed to complete this work, unless compliance were phased in over a number of years, similar to the MOD-024 and MOD-025 standards with respect to generator testing.	A review of the studies required for R2.1 indicates that at least 6 powerflow modeling scenarios would need to be completed to cover the base cases and sensitivities, which would be a 50% increase in the amount of work presently performed to meet the existing TPL-001 through 004 requirements for the near-term assessment. A review of the studies required for R2.4 indicates that at least 4 stability scenario models would need to be completed, which would be a 100% increase in the amount of work presently performed. Our present compliance performance and analyses activities take approximately 30 man-months to complete. We would expect the additional study analyses to add an additional 20 man-months of work and require 4-5 additional engineers at an annual cost of $400,000 to $500,000 (including benefits), given the regional requirement to complete the annual assessment by July 1.
City of Tallahassee, FL	we estimate a cost of $100,000 minimum since the City would likely have to outsource some of this analysis in addition to the work done by in-house system	hard to give a good estimate since the full ramifications of the required studies is not clear in the current draft. I would estimate 2 years at least.	similar costs to what was estimated above for the supplemental study cost, since staffing level is such that much of this ongoing work will likely be outsourced.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	planning staff.		
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its analysis requirements. Analysis of existing studies will undoubtedly uncover substantial additional study that would need to be performed, but the costs of such analysis and studies could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work that would only determine if we were in compliance, not including any work necessary to determine what would be necessary to bring deficiencies in to compliance.	It would not be unreasonable to find that it takes one full planning horizon (10 years) to complete supplemental studies and analysis for the draft standard, because it is so prescriptive. Requirements such as R2.2.1 that requires that the planning assessment be extended for longer lead time projects (such as the multiple new nuclear projects being considered across the U.S.) and R2.4.1 that specifies "...including the behavior of induction motor loads" will likely invalidate past studies that took considerable time to perform and would have to be reproduced with the newly required considerations. Requirements such as R2.6 (and subrequirenments) invalidate many existing studies, because of subjective terms such as "material changes" and "would impact the study area" without definitions of "material" or "impact". Re-analyzing all existing studies and re-writing the results and conclusions using the new terminology (P0, P1, P5 etc. instead of Category A, B or C2, C3, C5 etc.) used in the new performance tables will also add substantially to the effort needed to insure compliance and make the information auditable.	$ 5 million dollars annually is perhaps very conservative.
CenterPoint Energy and CPS Energy	We have no analysis to support an answer to this question, and we believe any such analysis would be speculative. We believe the reality of the situation is that the requirements are not practically achievable	3-4 years, assuming reasonably practical interpretation of the impractical requirements.	

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	at any cost, so the ultimate cost would depend on practical interpretations of impractical requirements. Even if the cost could be reasonably estimated, we oppose detracting valuable expertise away from necessary, value-added analyses to unnecessary, over-reaching theoretical analyses and documentation for audit purposes.		
SRP	The additional study work associated with this Standard could cost up to SRP $100k.	1 to 2 years to complete these additional studies.	Estimate addition on-going costs of $50k.
MidAmerican Energy Company	MEC estimates that the total cost for one-time software licenses would be about $100,000.	MEC estimates that the lead time to perform supplemental studies and analyses to meet the new requirements would be 2 years.	MEC estimates that the on-going additional cost of expanded studies and analyses to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees.
Tucson Electric Power Company	$200,000	6 month study performed by consultant	1 man-year
SERC Dynamics Review Subcommittee	The sensitivities will greatly increase the cost and time need for planning because the work is directly proportional to the number of sensitivities.		
MRO NERC Standards Review Subcommittee	The MRO estimates that the additional one-time costs of supplemental studies and analysis to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. The MRO estimates that the total cost over five years for additional staff, consulting services, or software fees would be about $200,000 to $300,000 per	The MRO estimates that the lead time to perform supplemental studies and analysis to meet the new requirements would be up to 5 years.	The MRO estimates that the on-going additional cost of expanded studies and analysis to meet the new requirements would be about $150,000 to $200,000 for additional staff and continuing software fees per responsible entity.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	responsible entity.		
Modesto Irrigation District	Unknown at this time.		
Midwest ISO	Some additional costs will be required to comply with all the requirements. This is difficult to quantify at this time.	This is difficult to quantify at this time, but any increased requirements should be clearly identified by the SDT and a transition period should be developed if the standards are intended to be more restrictive.	There will be an increase in ongoing cost for expanded studies and analysis. A transition period for staffing and process development will be required.
Tri-State Generation and Transmission Association, Inc.	Scenario assessments will significantly increase workload. Development of dynamic load models is ongoing, and will need a much longer implementation period than the steady state portions of the standard. As much as $500,000 may be required to address all of R2.1.3 scenario requirements.	It would take as much as two years for the initial supplemental studies with existing staff.	Ongoing additional sensitivity and dynamic studies would cost approximately $300,000 per year.
AEP	Additional one-time cost of 33 man-months	2 years	Additional ongoing cost of 12 man-months
Lakeland Electric	Unknown	Unknown	Unknown
Brazos Electric Power Cooperative, Inc.	We have no real way to estimate this or determine these costs.	Again, we have no real feel for making an estimate but it would be safe to say that the studies would take longer than the planning window. In other words, the results would not be completed before we would have to start them over again.	
NERC and Regional Coordination	Clarity about the exact number of supplemental studies required needs to be added to the standard before this question can bee addressed. The requirements		

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
	contained within the standard are nebulous. The requirements need to clearly state the depth of the studies required for each time horizon.		
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.		
IESO	Minimal, if any, since the IESO has been conducting and documenting planning studies that meet events and performance criteria that are very similar to those specified in the draft TPL-001 standard. However, this is speculative at this time since we are not sure what the eventual standard will be like. Another uncertain area is the extent to which additional studies are required if sensitivity testing is mandated. Please see our comments under Q2 and Q10 on sensitivity testing. If sensitivity testing should become a requirement, then the scope is very wide and we are unable to have a good handle on the incremental time and cost to supplement past study portfolio.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
North Carolina Electric Membership Corp	N/A	N/A	N/A
ERCOT System Planning		At least 4 years. It will take as long as the largest entity in our system which has estimated about 4 years. We are totally dependent on them for all data needed for these studies.	he workload to support the existing TPL-001 to TPL-004 has already consumed two full-time senior positions. Add to that the new requirements for steady state studies necessary in this standard would take at least another full time position. The new stability study requirements and short circuit requirement added would double the number of people necessary for a total of approximately six full time positions with moderate to high experience levels. (Four incremental FTEs with estimated annual cost of $650,000). Purchasing additional licenses for study software is an additional expense.
American Transmission Company	We estimate that the additional one-time costs of supplemental studies and analyses to meet the new requirements might be spread over five years because some analysis only has to be updated every five years. So, we estimate that the total cost over five years for additional staff or consulting services may about $200,000 to $300,000.	We estimate that the lead time to perform supplemental studies and analyses to meet the new requirements might be up to 5 years.	We estimate that the on-going additional cost of expanded studies and analyses to meet the new requirements might be about $150,000 to $200,000 for additional staff.
New York Independent System Operator	A very preliminary estimate would be potentially millions of dollars.	Again, a very preliminary estimate would be two years.	Preliminary estimate is on the order of hundreds of thousands of dollars In addition to cost, there is a significant concern over whether or not there will be

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
			enough staff to complete the required work.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	One component of these costs is based on modification to the loadflow database. A massive effort would need to be undertaken to model bus sections and breaker codes in order to simulate the planning events needed to stay current with the new standards. Also, man-power to perform the extra analysis was considered. Additional man-power: 5 engineers (2 years) Cost: $1,000,000	The majority of the time would be spent modifying the loadflow database so that the new planning event simulations could be analyzed. Time: 2 years	Additional man-power: 4 engineers Costs: $400,000 / year The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	Cost to supplement past study portfolio would be between $250,000 to 750,000.	3 to 5 years with added resources (staff)	$500,000 annually
ISO New England Inc.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have. Therefore cost can not be reasonably speculated.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the planning studies, but a very rough thought would be that any additional needs would be captured within the normal planning studies, which would likely occur within two study cycles of the effective date of the standard.	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on study effort and the associated cost. In addition to cost, there is a significant concern over whether or not there will be enough staff to complete the required work.

Organization	1 - Question 12 Comments:	2 - Question 12 Comments:	3 - Question 12 Comments:
Orlando Utilities Commission	$75,000 to supplement past study portfolio. (We have a fairly small system, only 1400 MW)	Two years, one year to recruit additional planner, the second to perform the baseline studies. This assumes there are sufficient trained personnel in the industry and they can be recruited.	$75,000 each year.
Entergy Services, Inc.	Cost will be covered by the on-going study costs as indicated below.	18 to 24 months	$1,200,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.			

13. **Documentation: One time cost to prepare reporting documentation associated with studies needed to supplement past study portfolio (depending on the time required to complete the supplemental work, this may be an accumulated cost over more than one year) – and on-going additional cost for documentation of expanded studies and analysis:**

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
Dominion - Electric Transmission Planning	The initial process development and documentation will be the most difficult and time consuming portion. Dominion - Electric Transmission recommends a period of 3 to 5 years be given for this initial period of becoming compliant and preparing the documentation. As noted above, it is difficult to provide cost estimates, but we expect at least 2 to 3 additional resources will be required, at a minimum.	See response above.
NPCC	See above	
TVA System Planning	Additional man-power of 1 engineer (1 year) would be required at cost of $100,000	Additional man-power of 1 engineer at costs of $100,000 / year
Progress Energy Carolinas	$60,000	$20,000/year
BCTC	Included in the above. We do not do analysis without documentation.	Included in the above. We do not do studies without documenting them
Manitoba Hydro	$200,000	$100,000
Los Angeles Department of Water and Power	This assumes that past studies are inadequate and supplemental studies are needed. The standard does add a lot of duplicative and unnecessary operating scenarios that are already required	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	under TOP and MOD; but they should be deleted because they serve no useful purpose under TPL, why even spend an extra penny if it is for naught.	
National Grid	See response to question 12.	See response to question 12.
Pacific Gas and Electric Co.	This cost would be included in the cost of performing the supplemental studies.	This cost would be included in the cost of performing the expanded studies and analysis
Gainesville Regional Utilities	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.	Probably would be covered in the previously provided annual cost. Again, I don't feel this is needed for smaller utilities.
JEA	Included in Question 12 estimates.	Included in Question 12 estimates.
PacifiCorp	$250,000 over two years	$125,00
Puget Sound Energy, Inc.	$150,000 for the STD in its current form.	$50,000
ITC Holdings: ITC, METC, ITC Midwest	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.	While we recognize that the standards might require us to garner a little more manpower and will take a little more time, we believe that running these studies is important.
Idaho Power Company	Appx $50k	Appx $50k
Hydro-Quebec TransEnergie (HQT)	See Q12	
Progress Energy Florida, Inc.	Again, these costs cannot be reasonably estimated given the difficulties stated in the answer to Question 12a. It would reasonable to expect that the number of individuals in PEF's Transmission Planning group would have to dramatically increase, at least doubling in size or possibly significantly more	Documentation cannot be separated from the actual analysis itself, and thus would be included as part of the $1M estimate stated in the answer to Question 12b above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	than doubling.	
Sierra Pacific Power Comapny / Nevada Power Company	$100,000	$50,000
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	$200,000.00	$100,000.00
Ameren	Documentation preparation to include the short-circuit assessment, the amount of consequential load dropped for single contingencies, the expanded requirements of the Corrective Action Plan, and how the sensitivities affect the Corrective Action Plan would take a man-week or two at most (no significant cost increase or manpower increase).	Our present documentation activities to develop the assessment and the corrective action plan take approximately 2 man-months to complete. We would expect the documentation to cover the additional study analyses to add an additional 2 man-months of work. The additional documentation for the Consequential Load Loss, short-circuit analysis, expanded requirements of the Corrective Action Plan, and documentation of how the sensitivities studied affect the corrective plan are estimated to double the existing reporting requirements, resulting in an increase of 3.5 man-months and require 2 additional engineers at an annual cost of $200,000 (including benefits), given the regional requirement to complete the assessment by July 1.
City of Tallahassee, FL	documentation cost was included in the cost estimates for #12, since development of the documentation is part of the study work scope.	
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its documentation requirements. Analysis of existing studies will undoubtedly uncover substantial additional documentation that would need to be produced, but the costs of such document production could not be reasonably estimated beyond stating that the costs would be significant resulting from 1000's of man-hours spent on supplemental work	This would be included in the $5 million dollar estimate provided above.

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
	that would only serve to meet audit requirements.	
CenterPoint Energy and CPS Energy	As with our response to question 12, we believe the answer depends upon the ultimate practical interpretation of the impractical requirements.	
SRP	Estimate $30k to prepare documentation.	Estimate $15k each additional year documentation.
MidAmerican Energy Company	Included in amounts for 12.	Included in amounts in 12.
Tucson Electric Power Company	included in previous question	included in previous question
MRO NERC Standards Review Subcommittee	Included in amounts for 12.	Included in amounts for 12.
Midwest ISO	We agree some additional costs will be incurred for expanded documentation.	ore requirements and more studies will increase documentation costs.
Tri-State Generatino and Transmission Association, Inc.	An additional $100,000 would be required to document studies for compliance purposes.	Perhaps $50,000/year - half of the initial amount required.
AEP	Additional one-time cost of 15 man-months	Additional ongoing cost of 7 man-months
Lakeland Electric	Unknown	Unknown
NERC and Regional Coordination	Clarity about the required documentation and coordination needs to be added to the standard before this question can bee addressed. As written, our interpretation is the increase in documentation requirements is substantial.	

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	
IESO	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.	Minimal, if any, for the reasons indicated above, other than for meeting the sensitivity testing requirements (if mandated) which cannot be quantified.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	We estimate that the one time cost for expanded studies and analysis documentation to meet the new requirements might be about $20,000.	We estimate that the on-going cost for expanded studies and analysis documentation to meet the new requirements might be about $10,000.
New York Independent System Operator	included above	included above
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Additional man-power: 1 engineer (1 year)Costs: $100,000	Additional man-power: 1 engineer Costs: $100,000 / year. The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere

Organization	1 - Question 13 Comments:	2 - Question 13 Comments:
		near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric Delivery	$250,000	$100,000
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$25,000	$25,000
Entergy Services, Inc.	$150,000	$100,000 / year
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

14. **System Reinforcement: One time cost, capital investment, to expand your system reinforcement program (due to lead times associated with different types of facilities, this will probably be an accumulated cost over several years). How many years do you estimate that it will take to complete this initial expanded system reinforcement program:**

Summary Consideration:

The SDT has reviewed the responses and will use the data as background information in making any further decisions with regard to this standard. No direct changes were made to any of the requirements at this time based on this information.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Dominion - Electric Transmission Planning	Difficult to estimate the investment required, but it will be in the millions if not hundreds of millions of dollars.	Siting new transmission in Virginia can take a minimum of 5 to 7 years if new right-of-way acquisition is required. It is difficult to provide an estimate of time, but it will be quite extensive.
NPCC	NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also NPCC participating members expressed concern that a validly conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	See above

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
TVA System Planning	Costs would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Estimated cost of $1 billion	Time duration of 10 years would be required
Progress Energy Carolinas	$100,000,000	10 years
BCTC	We do not believe that this cost is not relevant for determining the applicable standards and have not estimated it. The reinforcement costs are orders of magnitude greater that the costs of alternatives the changes in this standard propose to prohibit (e.g. use of RAS, curtailment in anticipation of the next contingency). We believe it is very unlikely that we would get approval for the projects that would be required to meet the proposed changes.	It is highly unlikely that we would be able to get funding approval for the system reinforcements required to meet the proposed changes in these standards.
Manitoba Hydro	An estimate of the cost to Manitoba Hydro is $1.0 Billion.	The licensing and construction of facilities to achieve compliance will require at least 10 years.
Los Angeles Department of Water and Power	If this question is referring to discriminatory treatment between different voltage classes that is arbitrary; the effort should be directed to either treat all the voltage classes equally or do come up with a scientific or historical basis to support the requirement. This is an engineering standard, all the criteria should have some scientific/engineering rationale that can be supported either by physics or historical data.	
National Grid	The comment period was not long enough to develop a thoughtful response to the impact that the new standards might have on the construction requirements. Therefore cost can not be reasonably speculated.	At least 5 beyond the study period. Lines requiring new Rights-of-Way may require 10.
Pacific Gas and	The capital investments would be dependent on the system	Any transmission facilities that would require a certification of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Electric Co.	reinforcements needed due to the added requirements. For example, if after the first contingency, redispatch to curtail firm transfers is not allowed in anticipation of the next single contingency, the system reinforcements could easily include more 500 kV lines and related facilities. The costs of such reinforcements could be a few Billion dollars.	public convenience and necessity could take more that five years for permitting, engineering and construction. Transmission Planning could take a few more years depending on the transmission reinforcements to be constructed.
Gainesville Regional Utilities	$50 Million. Again, I don't feel this is needed for smaller utilities.	7 years. Again, I don't feel this is needed for smaller utilities.
Public Service Company of New Mexico	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, costs could run into the hundreds of millions of dollars.	This ultimately depends on the degree to which the local area issues addressed by footnote b of Table 1 of the existing TPL are maintained. Without the local area concepts of the existing TPL, permitting requirements would result in some projects exceeding 10-years.
JEA	Could be up to $1 Billion and would depend on the physical ability to terminate at existing 500 kV substations and the ability to acquire 500 kV ROW outside of JEA's and Florida's jurisdiction.	Minimum of 7 years if DOE declares a Corridor of National Interest. Otherwise it could be longer and more costly.
PacifiCorp	$100,000,000 + Will not be able to estimate the total cost until after the studies are complete.	10 years
Puget Sound Energy, Inc.	$800,000,000 to recover Firm Transmission capacity with no adjustment following N-1.	15 years
ITC Holdings: ITC, METC, ITC Midwest	Since we have been following the NERC Planning Standards, at this point we do not expect an additional one time system reinforcement cost.	Since we have been following the NERC Planning Standards, at this point we do not expect an additional time-frame for a system reinforcement program.
Idaho Power Company	Not sure	5 years
SMUD	A field test of the revised standard would be the appropriate way to arrive at the approximate costs to support the new/modified	A field test would be the time to get an educated estimate.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	requirements.	
Hydro-Quebec Transenergie (HQT)	HQT and NPCC participating members have expressed compliance concerns that this standard, and in particular this question, imply NERC has the ability to "force" transmission reinforcements and construction. It should be emphasized and clarified that the standard should require transmission studies only, and per the Energy Policy Act, NERC does not have this authority as the ERO as granted by FERC in the US and NO authority allowing this in Canada. Also HQT and NPCC participating members expressed concern that a validly-conducted assessment which shows that criteria are not met (in the 5 or 10 year horizon) could result in non-compliance with the Standard. If NERC believes that it can issue monetary penalties for 5 or 10 year assessments that show that performance criteria will not be met under future system conditions, there is a key question that requires explanation: What behavior is NERC attempting to incent through fining parties for conducting assessments which identify problems in a 5 to 10 year horizon? Also, NERC should further explain how it would view the relevance of a State or Provincial decision not to permit new facilities when issuing such a potential penalty such as preclusive siting issues with Generating Plants.	
Progress Energy Florida, Inc.	Again, due to the difficulties described in the answer to Question 12a, given that the amount of analysis cannot be reasonably estimated, neither can the one-time capital cost. PEF did state in the answer to Question 11 that the cost to our 500 kV system alone would easily run in to the range of costing billions of dollars. How many billions, we are not sure, but we have sufficient experience through presently planned 500 kV projects on our system to know that the cost for such expansion is in the range of billions of dollars. Given that PEF has not been able to comprehensively assess the costs to its 230 kV and 115 kV system, it is likely that the total cost of implementing the draft TPL Standard would be many, many billions of dollars. As stated earlier, this concern is reinforced in the answer to Question 15, but	PEF does not believe the undertaking required in the present draft of the TPL Standard, questionably described here as an "initial" program, could reasonably be implemented in our lifetime. As stated in our answers to Questions 12 and 13, the planning time would run at least 10 years, or one complete long-term planning cycle. Implementation, particularly given the scope of 500 kV projects and challenges with operating the existing system while constructing such large projects, will take an additional 10 years. An estimate of 20 years, however, assumes that the industry is in place to make such projects feasible continent-wide. Just a cursory assessment of the limited resources of the Transmission Construction industry, combined with the global demand for concrete and steel, leads us to conclude that implementation of

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
	we are extremely concerned that our ratepayers will potentially be burdened with such exorbitant cost for so little benefit, and are certain that our PSC and our ratepayers will agree.	the draft Standard's requirements is not feasible short of a World War II-scale re-tooling of our entire economy. Given the significant challenges the U.S. economy is already facing, the prudency of such a colossal undertaking with minimal benefit becomes even more questionable.
Sierra Pacific Power Company / Nevada Power Company	$800 Million	10 years
Lafayette Utilities System	See response to part 1 of Question 12.	See response to part 1 of Question 12.
Arizona Public Service Co.	Hard to quantify without studying.	5 years
Ameren	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system. The modification to remove the requirement that bus-tie circuit breakers must have the same performance requirements as non-bus-tie breakers significantly reduces our issues of non-compliance, and particularly for circuit breakers 300 kV and above.	Our present interpretation is that the proposed revised standard would have a minimum impact on the reinforcement of the Ameren system.
City of Tallahassee, FL	depending on the interpretation of the standard as currently drafted, this cost could be substantial (at least $20M) over a 5-year capital budget period (consistent with the City's current practice). It's doubtful this level of funding could be achieved/maintained given other financial pressures for local governments.	Unable to develop an answer to this question, since it depends on the ability to successfully site and permit generation and transmission facilities (which is becoming increasingly harder to complete), and the requirements of any successful siting effort may make the costs prohibitive (ie, underground transmission facilities and/or stringent controls on generating facilities).
Florida Power and Light	These costs cannot be determined without having experience with the new standard and its performance requirements. The costs of such investment could be in the 10's of billions of dollars for FPL because of the increased level of performance contemplated by the draft standard.	If we knew what was needed today, it could conceivably take up to 10 years to complete, if the projects are all feasible. Without knowing what is necessary, a fair estimate would be 20 years. This does not take into consideration that the entire industry would be competing for the same limited resources of material and manpower to complete this reinforcement. Justification would be

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
		problematic and eminent domain may not be enforceable due to the remote low probability of an N-1-1 event, and lack of a true reliability need.
Exelon Transmission Planning		Analysis has not been completed at this time to determine the extent of the additional burden, but significant expenditures, in terms of personnel, tools and transmission upgrades, are anticipated if this draft were implemented.
CenterPoint Energy and CPS Energy	We believe the proposed requirements may not impose additional capital investment for system re-enforcements for our companies. We believe we are already achieving the reliability goals embodied in the proposed requirements but in a much more efficient and cost-effective way than the overly prescriptive approach proposed in these requirements.	
SRP	Unknown costs, there are numerous raise the bar Standards, hard to determine the additional cost to SRP until the complete studies are performed and evaluated.	Unknown until the reinforcements are determined.
MidAmerican Energy Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then MEC estimates that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, MEC estimates that it would take 5 to 7 years to complete the new projects.
Tucson Electric Power Company	unable to determine without actual studies	10+ years5 year budget and 10 year plans have been approved. Proposed projects in the 5-10 year time frame would need revised and accelerated and new projects would be proposed following the completion of these proposed projects.
SERC Dynamics Review Subcommittee		The lead time for new line construction is at least 7 years.

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
MRO NERC Standards Review Subcommittee	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we estimate that it would cost in the range of hundreds of millions of dollars per responsible entity.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it would take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
Midwest ISO	This is difficult to quantify at this time.	This is difficult to quantify at this time.
Tri-State Generatino and Transmission Association, Inc.	We do not anticipate additional investment beyond currently planned facilities.	Transmission projects generally take between 3 and 6 years to complete.
Tri-State G&T		10-Jun
Lakeland Electric	Unknown	Unknown
Southern Company Transmission	These costs cannot be determined without having experience with the new standard and its performance requirements.	
NERC and Regional Coordination	Clarity needs to be added throughout the requirements. Our interpretation of the standards as written will not result in substantial capitol investment. These standards will not have a substantial impact on improved system reliability, however; the requirements do significantly increase the manpower investment in study documentation and efforts associated with reporting study results.	
ColumbiaGrid	The new TPL Standard raises the bar of transmission system performance. This can be expected to require significant additional analysis, documentation and system reinforcements (or reduced firm transfers allowed on the system if system reinforcements are not made). We will defer to our members to provide quantification of those elements.	

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
IESO	None expected at this time.	None expected at this time.
Northeast Utilities	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.
North Carolina Electric Membership Corp	N/A	N/A
American Transmission Company	The additional one-time costs of system reinforcements to meet the new requirements would depend on the results of the new studies and be hard to forecast. However, if they involved just a few 345 kV substation modifications and 345 kV line additions, then we would estimate that it costs may be in the range of hundreds of millions of dollars.	The lead time to build new system projects would depend on the results of new studies and be hard to forecast. However, if they involved a 345 kV substation modification or a 345 kV line addition, we estimate that it might take 5 to 7 years to complete the substation project and 8 to 12 years (or more) to complete the new transmission line project.
New York Independent System Operator	Depending on facilities covered by the standard, it is estimated that the cost to bring facilities into compliance potentially could be on the order of billions of dollars.	A preliminary estimate is that it would take at least five but potentially up to ten years to bring facilities into compliance.
SERC Reliability Review Subcommittee and Planning Standards Subcommittee	Typical costs for a large utility in SERC would include the implementation of redundant protection schemes for the P5 planning event (fault + failure of protection scheme), additional 500-kV facilities for P2.2 (single contingency - bus section outage) and P4 (fault + stuck breaker) events, and additional 161-kV facilities for the P3 (Generator +1) events. Cost: $1 billion	Time: 10 years The following analysis was performed by one large integrated utility in SERC. The results are not representative of all utilities in the SERC region, but would be multiplied many times over to fully represent the SERC region as a whole. A comprehensive study of the impact of these proposed and incomplete standards is not feasible until they are finalized. Regarding manpower, aside from the estimated costs there is the very real situation that the number of qualified engineers available in the industry is nowhere near what would be necessary to carry out the studies (including sensitivities) called for by the proposed standard. This reality needs to be taken into consideration by the Standards Drafting Team when it makes its implementation plan recommendations.
Oncor Electric	Unknown, dependent on results of analysis and solutions	Unknown, dependent on results of analysis and solutions

Organization	1 - Question 14 Comments:	2 - Question 14 Comments:
Delivery	implemented	implemented
ISO New England Inc.	See response to question 12.	See response to question 12.
Orlando Utilities Commission	$0.00 if system adjustment in preparation for the second part of N-1-1 can include firm transfer and non-consequential load adjustments when necessary. $500 Million if n-1-1 conditions must be met without firm transfer and non-consequential load - adjustments before the second event, at 230 kV and above$1 Billion if n-1-1 conditions above are met on load serving systems below 230 kV.	10 Years to meet n-1-1 without curtailment/reduction prior to the second n-1. A significant portion of the work would be in either downtown, established residential or highly sensitive environmental areas, all of which may require extensive legal proceedings to build the projects. There would also be a large amount of simultaneous work going on nationwide that would result in a shortage in construction & design personnel as well a scarcity in needed materials.
Entergy Services, Inc.	Without performing the requisite analyses, Entergy does not know definitively how much it will cost to comply with these revised standards. However, Entergy expects the cost could be up to $1 billion to become fully compliant.	15 - 20 years The time required for construction will be elongated due to the need for significant numbers of new construction projects. This will require that projects be queued by the TPs because of constraints in available materials, labor and other resources.
BPA Transmission Reliability Program	This information is not available.	This information is not available.
Response: The SDT thanks all who responded to this survey question.		

15. (A) Do you generally support the revised standard? (B) Are you unsure whether you generally support the revised standard? or (C) Do you definitely not support the revised standard? Please check the appropriate box below. If your response is either (B) or (C), please explain your single biggest concern with the revised standard, including which specific requirement or set of requirements causes you the most concern and why.

A – Generally support the revised standard
B – Unsure about supporting the revised standard
C – Definitely do not support the revised standard

Summary Consideration: 50% of the commenters voted that they did NOT support the revised standard at this time. 35% are unsure. Some of the major issues that were raised by the industry for Question 15 include:

1. System Adjustment in event P6 - Many commenters believe that after the first N-1 in P6, curtailment of Firm Transmission Service or firm transfers should be allowed as part of System adjustment in preparation for the next N-1, citing that this is presently allowed in footnote b in existing Table 1. Otherwise, the Firm Transmission Service under normal System intact condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. Many believe this would in effect be imposing an N-2 criterion for offering Firm Transmission Service.

SDT response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Revision 3 of the Standard provides clarification.

2. Dropping local load - Many commenters opposed not being able to drop some local network Load for a single Contingency event as long as Bulk Electric System reliability was not impacted. This is presently allowed in footnote b of the existing TPL-002. However, there is no such allowance any longer for losing Non-Consequential Load for a single Contingency in the proposed draft. Many commenters suggested that orderly dropping of local network Load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. Some local network customer curtailments or local area Load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected System was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service.

SDT response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and 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. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. Raising the bar for 300 kV and above - Many commenters believe that the SDT has not yet justified raising the bar on Facilities above 300 kV. Some pointed out that the higher performance requirements for Facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. Some also pointed out that disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. Many believe that there should be no distinction in voltage classes for allowing or not allowing controlled Load shed for applicable events.

SDT response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

4. Load modeling for dynamics - Many commenters believe that Load modeling is a significant open issue, such as the models for dynamic studies have yet to be developed and the data is not yet in hand. Many find this conflicting with implementation of the TPL standards due to modeling details being a gating item to completing some System studies.

SDT response: The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

5. Sensitivity analysis - Another concern of commenters is the prescriptive nature of sensitivity scenarios, listed within Requirement R2.1.3 for steady-state and Requirement R2.4.3 for Stability, and the volume of associated study work. Some commenters feel that the Transmission Planner and Planning Coordinator can better select the most appropriate sensitivities for their System. Commenters also feel that examples of sensitivities are already inherent in the existing requirements, such that some sensitivity studies are in effect adding an additional level of Contingency (N-2 or N-3). Many commenters feel that the additional analyses proposed by the revised standard are not warranted and are already covered adequately in the existing studies and TPL standards.

SDT response: The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand the planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706.

As a result of industry comments, the following changes have been made to TPL-001-1:

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

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

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 ~~completion of the previous annual Planning Assessment~~ current calendar year.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R2 Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~.

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

- ~~Variability and outages of r~~Reactive resource~~s~~ capability

R2.1.4 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 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 due to the unavailability of the long lead time equipment.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

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

R2.6.1 (now R2.5.1) For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less.

R2.6.2 (now R2.5.2) For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

R2.7 (now R2.6) For Planning Events shown in Table 1~~ – Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 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 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:

Under Requirement R2.6.1:

- Installation or modification of Protection Systems or Special Protection Systems
- Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations.
- Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations.

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.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~C~~ontingencies in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.4.

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation

R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R4.3.2 ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~.

R4.4 ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~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 created~~,~~. ~~and t~~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.

R7. Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators 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.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Extreme Event 2b (steady state) - Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way.

Footnote 1.a.ii - For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.

Footnote 3 - 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 fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – 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 be considered.

Footnote #12 - Excludes circuits that share a common structure for 1 mile or less.

Organization	Question 15:	Question 15 Comments:
El Paso Electric Company	B — Unsure about supporting the revised standard	While this 2nd draft TPL standard has some positive changes, notably: The allowance to use RAS to trip generation for N-1 (see R3.5 Manual and automatic generation run-back/tripping is allowed as a response to a single or multiple Contingency ...) with some rather generic conditions. The allowance for Non-consequential Load Loss for loss of a transmission Facility, followed by system adjustment, followed by loss of a second transmission Facility (see P6 in draft performance Tables 1 and 2). This is the same as Category C3 in the existing TPL-003-0.On the down side, as proposed, Standard TPL-001-1:1. Will not allow curtailment of firm transfer (or firm transmission service) after the first N-1, in preparation for the next N-1 regardless of transmission voltage level. This is a major issue. Curtailment of firm transfer after the first N-1 has always been a part of system adjustment in preparation for the next N-1 as stated in foot note b of the existing TPL-002-0:"b. Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." Not allowing this could mean reduction of firm transfer capability pre-contingency unless new circuits are built.2. The existing standard (http://www.nerc.com/files/TPL-003-0.pdf) does not distinguish between voltage classes, curtailment of firm transfer and, planned and controlled load shedding are allowed regardless of voltage class for Category C events. The proposed standard will not allow curtailment of firm transmission service, or planned and controlled load shedding for loss of Facilities with operating voltage above 300 kV involving the following in the proposed Performance Tables 1 and 2:P2-2: Bus Section fault (Category C1) P2-3: Breaker fault (Category C2) P4: SLG Fault + stuck breaker (Categories C6 - C9) P5: SLG Fault + protection system failure (Categories C6 - C9)The number of Facilities lost would depend on the bus configuration for above 300 kV. If you have a ring-bus, breaker and a half or double breaker double bus, you would lose at the most 2 Facilities. But if you have Main-Aux or single breaker double bus, you will lose all Facilities connecting to the faulted Facility.
Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as System adjustment after		

Organization	Question 15:	Question 15 Comments:
an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote 10** – 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 be considered.		
Dominion - Electric Transmission Planning	B — Unsure about supporting the revised standard	(1) Unsure about cost/effort necessary to meet requirements (2) Uncertain that compliance with the proposed requirements in this standard would significantly improve reliability (3) R2.6.2: The entire sentence is confusing as it is modified. The original sentence in the previous draft made more sense. Please check and correct accordingly. (4) R 5.3: This requirement considers voltage ride-through capability of all generators. Nowhere in this TPL standard or in the MOD standards are Generator Owners specifically required to provide such data to Transmission Planners and Planning Coordinators. Stating the requirements for generator dynamics data and dynamic load characteristics in general terms, as listed below (from the MOD Standards), are vague. (a) shall provide appropriate equipment characteristics (b) shall provide dynamics system modeling and simulation data (c) Shall develop comprehensive dynamics data requirements .... to model and analyze the dynamic behavior... (5) In Table-2 Stability Performance, several places refer to "SLG or 3-phase Faults" . Since it states "or", does this mean we can get by with studying only SLG faults? We do not think that is the intent of this phrase; thus, a clarification is warranted. (6) One of our comments on the previous draft was with respect to a second-zone fault clearing due to protection system failure for a fault beyond zone 1 coverage of primary relies. The SDT's response was (Specific 1): "The SDT agrees with your concern and is working on a solution for a future draft." The question is repeated below, as a pending "to do" item, using the revised 'Table-2 Stability Performance' as reference: Category 5 in 'Table-2 Stability Performance' refers to a protection system failure event. We interpret this as, among other things, having a fault beyond the first-zone coverage of the primary protection scheme with the carrier equipment failure (or the carrier cut-off switch left in "OFF" position by a technician - a human error) resulting in a second-zone trip of the faulted line. The second-zone trip time is generally in the range of 30-35 cycles. This may be critical from the stability aspect for the terminal end at a generating plant even though only one element will be lost. Also, the second-zone trips may need to be studied for transmission lines out of next terminal from the generator end if the next terminal is connected to the generator terminal via a short line. We think that an

Organization	Question 15:	Question 15 Comments:
		additional single contingency Category should be added to this Table to cover the "Event" of second-zone trip scenario.

Response: 1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors and additional efforts involved and has taken them into consideration in its deliberations in the development of this draft.

2. The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT agrees and is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3. The SDT has revised the language of Requirement R2.6.2 (now R2.5.2).

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

4. The SDT understands that the Transmission Planner and the Planning Coordinator need data from the Generator Owners. However, revising the MOD standards is beyond the scope of this standard revision. Further, we note that one of the requirements of FERC Order 890 for long-term Transmission planning involves formal data exchange between stakeholders and the Transmission Planner and the Planning Coordinator. It is our understanding that these data exchange processes have been successful in providing better planning information about stakeholders such as independent Generator Owners. Also, we note that there is an ongoing standards development project, Generation Verification Project 2007-2009. You may wish to submit your comment to that SDT about the need for the Generator Owner providing this information to the Transmission Planner and the Planning Coordinator.

5. The SDT has combined the tables into a single table and clarified the "SLG or 3 phase" designations. In addition, the SDT has added footnote 3 to provide clarity.

Footnote 3 - 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 fault study indicating criteria are being met shall provide sufficient evidence that a SLG condition would also meet criteria.

6. The SDT has revised the language in the P5 category to clearly identify the required performance for an event with a Protection System failure. The current draft requires the planner to recognize the equipment that will be removed from service and the timing (including delays with back-up Protection Systems if the primary is out of service) during their Stability studies. The scenario you described is therefore covered by P5. The SDT does not see a need to have a separate event for that scenario.

NPCC	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall

Organization	Question 15:	Question 15 Comments:
		reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard. c. Put headings on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment.

Organization	Question 15:	Question 15 Comments:
		l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon.
New York Independent System Operator	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. This comment form did not allow for the following items to be addressed: a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. b. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. c. Put headings on each section to identify requirements of section. d. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load study" and replace "study" with "assessment." e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of

Organization	Question 15:	Question 15 Comments:
		Consequential Load loss. It's not considered anywhere else in the standard. j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizion.
Northeast Utilities	C — Definitely do not support the revised standard	Northeast Utilities has participated with ISO-NE and NPCC and supports the comments filed by those organizations.

Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and 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. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

Organization	Question 15:	Question 15 Comments:

B. Planning Coordinator has been defined in another project and as such has been deleted here.

C. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

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.

J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events.

K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1**.**

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~C~~ontingencies in Table 1 – Steady State Performance.~~ The studies shall be

Organization	Question 15:	Question 15 Comments:
		based on computer simulations using models utilizing data provided in Requirement R1. **R4** For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment.~~ ~~The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ L. Requirement R5.3. has been modified (now R4.3.2) to address simulation of how generators perform under conditions being studied to address these concerns. "Other equipment" is addressed in Requirement R5.4. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~ M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied.
TVA System Planning	C — Definitely do not support the revised standard	TVA's main concern is that no technical justification for "raising the bar" on facilities above 300-kV has yet been demonstrated such as required on P2, P4, and P5 for 300 kV and above. TVA is very concerned that "raising the bar" would be a financial burden on TVA's ratepayers. TVA would also like to provide the following additional comments to this second draft as follows: 1. In R2.4.1, load models that appropriately represent the dynamic behavior of motor loads are required. TVA believes that industry guidance is needed on how to properly model these loads. Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? It should be clearly stated whether the load model in R2.4.3.1 refers to system load or the dynamic load model at individual busses. 2. In R3.2.1 and R5.3, need industry guidance on how to actually determine the minimum steady state voltage limitations of generators. Is there a MOD or FAC requirement for generation owners to provide this information? 3. Which single contingency events should be included in calculations for Available Transfer Capacity? Should P2 events be included in addition to P1 events since P2 events are also defined as single contingency events in Tables? 4. Would like further clarification from the team on what does P5 exactly includes? For instance, does it include battery failures, CT failures, etc? 5. 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

Organization	Question 15:	Question 15 Comments:
		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. 6. Suggest rewording R2.2.1 from "To accommodate any known longer lead time projects" to "To identify any potential longer lead time projects". 7. Can operational guides be used indefinitely in R2.7.1 or does the team propose a limit on how long operational guides can be used until a capital fix is implemented? 8. In R3.3.2.1, what is the purpose for needing the expected duration of consequential load loss? There is a concern that this requirement will be very burdensome to keep track of the quantity of consequential load loss as well as expected duration. Who is requesting this info? It appears that this may be a local regulatory issue, not a reliability issue. 9. Suggest changing definition of "Planning Events" in the Definitions to say "Events that have a higher probability of occurrence and require Transmission system performance requirements to be met." 10. Should the proposed standard mention that utilities should run contingencies outside their system that could impact their own internal system? TVA believes that additional documentation be included in the new standard to address this. 11. Functional entity in 4.1.4 should be "LSE" instead of "DP" 12. In the Definitions for "Year One", suggest replacing "previous" with "most recent" to help clarify when the planning window should begin. 13. Should "peak" in R2.1.1 be replaced with "On Peak" as shown in the NERC glossary of terms? Also the requirements in this requirement are too prescriptive - should allow some flexibility to allow the TP which years to study as long as a minimum number of cases are studied. 14. Suggest replacing "Plant" in R2.6.2 with "Unit" to match terms used in Definitions. 15. In R2.7.1.1, what is meant by "project initiation date"? Is it when engineering starts, construction starts, etc? 16. Suggest rewording requirements R3.3.3 and R3.4 to be more clear - such as breaking each of these into several sentences each. Existing wording is very confusing. 17. There is a concern with R5.6.1 with the requirement to perform simulation on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations. Also in R5.6.2, should last word in sentence be "greater" or "lesser"? 18. In the Tables under Extreme Events, is 3.b. (loss of two TLs on different ROWs actually already covered under 1 (loss of two elements prior to system adjustments)? Also in the Tables under Extreme Events, it may be difficult for a TP to know enough about nuclear plant design to perform studies mentioned under 3.a.vi.

Organization	Question 15:	Question 15 Comments:
		19. In the notes under Extreme Events, we suggest that notes #2 and #3 be combined together since they are very similar in nature. 20. Should the P3 planning event descriptor (G+1) in the performance tables be (G+N-1) or (G-1, N-1)? The existing descriptor (G+1) tends to note that an element is being added to the system instead of being removed. 21. Should the new standard address specific voltage limit requirements that must be maintained during these planning events? Since different utilities have different voltage limits on their buses, should there be some consolidation to ensure the standard is applied equally at all utilities? 22. The note for Planning Event P1 states that “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.” The standard does not allow consideration for small units with a Zone 2 fault. It is not practical to add pilot relaying on all lines from a plant with a small unit that would be stable for close-in three phase faults, and could be adequately protected when a Zone-2 fault would cause a small generator to trip off with out-of-step (OOS) protection. The table for P1 should allow small units (<75 MW) to trip using SPS or OOS protection.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04 Modeling Data and 2010-05 Demand Data. Requirement R2.4.1 has been modified to include the following: "An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable."

2. The SDT believes that FAC-009-1, Requirements R1 and R2 require that generators provide these low voltage limitations as part of their Facility Ratings. Also, PRC-024, which is under development, will attempt to require generators to meet voltage ride-through criteria.

FERC Order 693, paragraph 1773 regarding FERC Commission directed changes to TPL-002 states "...requires all generators to ride through the same set of Category B and C contingencies as required by wind generators in Order No. 661, or to simulate those generators that cannot ride through as tripping".

The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. Based on the proposed TPL requirement, Requirement R5.3 (now R4.3.2), it is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator

Organization	Question 15:	Question 15 Comments:

terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers.

3. Questions related to ATC calculations are beyond the scope of this standard. Please see NERC Reliability Standard MOD 001-1, Requirement R7 & Measure M7 for additional information on ATC calculations.

4. The description of the P5 event has been clarified in this Revision of the Standard.

5. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and 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.

6. The SDT believes that the existing language is appropriate. An assessment of year 15 would be needed to accommodate a Transmission line if it takes 15 years to build a line.

7. The SDT has not established a limit as to how long Operating Procedures may be used to meet System performance requirements and has left that decision for the Transmission Planner/Planning Coordinator.

8. By definition, Consequential Load Loss is allowed. To meet industry concern, as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

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.

9. The definition of Extreme Events already states that these events have a lower probability of occurrence than Planning Events. The SDT did not make the change suggested by the commenter as there was no industry consensus to alter the definition.

10. The list of Contingencies is expected to cover the Transmission Planner's or Planning Coordinator's System for which they are responsible, including any tie-lines to adjacent Transmission Systems. The standard does not preclude the Transmission Planner or Planning Coordinator to expand the list of Contingencies to include some Contingencies of interest or known impact for adjacent System(s). It is expected that through peer reviews, the Transmission Planner or Planning Coordinator may initially learn of any new event within an adjacent System that impacts their own System.

11. Applicability 4.1.4 has been deleted due to the deletion of Requirements R9 – 14.

12. The SDT believes that it is not necessary to replace "previous" with "most recent" since Planning Assessments are required on an annual basis.

13. The SDT believes that the term "System peak Load" is appropriate. The SDT does not believe that Requirement R2.1.1 is too prescriptive, but is the minimum needed to gauge the timing for System reinforcements in the near-term horizon.

14. This draft of standard has been revised to remove word "plant" from Requirement R2.6.2 (now R2.5.2). Requirement R2.5.2 from the last draft of the

Organization	Question 15:	Question 15 Comments:
standard has been deleted. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: 15. The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and/or Planning Coordinator. 16. Most of the industry did not seem to find Requirements R3.3.3 and R3.4 unclear or confusing. Therefore, the SDT has decided to not undertake any rewording. Requirements R3.3.3 and R3.4 have been relabeled as Requirements R4.4 and R4.5 respectively. 17. The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2. Requirement R5.5.2 was deleted. 18. The SDT agrees and has removed the redundancy found with Extreme Event 3.b. Having multiple nuclear units out of service simultaneously is an Extreme Event, but it has occurred. The SDT recommends that the Transmission Planner consider sensitivities with different combinations of nuclear plants being out of service, including the possibility that they are all shut down simultaneously. To reinforce the more apparent combinations, the Transmission Planner may discuss the operational requirements and the equipment and design similarities of the nuclear plants with the appropriate Resource Planner or Generator Operator to determine credible scenarios which could commonly affect the nuclear plants. 19. The SDT discussed the combining of notes 2 & 3 but felt they wanted them separate for clarity. Note 2 is focusing on interruptions of Firm Transmission Service and Non-Consequential Load and Note 3 refers to transformer outage events. 20. The SDT has deleted the parenthetical to provide clarity. 21. The SDT has addressed this issue by the Header note 'b' for Steady State Only in Table 1 - Steady State & Stability Performance, where the Planning Coordinator sets the acceptable voltage deviations. The SDT believes that adjacent Planning Coordinators can adequately address this concern. 22. The SDT believes that any unit that is tripped by out of synchronism protection is actually in an "out of synchronism" condition and this should not occur for a P1 event regardless of generator size.		
City Water, Light & Power - Springfield, Illinois	A — Generally support the revised standard	
Response: Thank you for your response.		
Omaha Public	B — Unsure	Event 1 of Category P2 in Tables 1 and 2 addresses events consisting of "Breaker(s) opening without a Fault resulting in a

Organization	Question 15:	Question 15 Comments:
Power District	about supporting the revised standard	single ended line." Category P2 is labeled as a "single contingency" category, yet it seems like an event consisting of the opening of more than one breaker would actually be a multiple contingency. Please consider whether the "(s)" should be removed after the word "breaker" in the event description so that it addresses only a single breaker opening without a Fault. Table 1 does not address multiple contingencies consisting of loss of a transmission circuit, transformer, single pole of a DC line, or shunt device, followed by System adjustments, followed by the loss of a generator. It seems like Table 1 should be modified to address this type of multiple contingency. In the description of Event 1 of Category P2 in Table 1, remove the text "Loss of one of the following:". In the description of Event 2 of Category P2 in Table 1, replace "Bus section" by "Loss of a bus section". Assuming that this does not change the intent of the drafting team, in R3.3.2.2, R3.5.1, R5.4.3.1, change "shall be operating" to "are operating". In R3.3.2.2, consider removing the phrase "and within their thermal and voltage limits", because it seems like it may be redundant given the definition of the term "Facility Rating". In the event descriptions of Categories P1, P3, and P6 of Table 2, does the term "3-phase fault" apply to DC lines? If not, consider using a separate introductory phrase with the event descriptions of Categories P1, P3, and P6 of Table 2 that involve DC lines. Also consider removing the words "Loss of" in the description of Event 4 of Category P6 in Table 2. Since a definition was developed for "Bus-tie Breaker", capitalize the terms "bus-tie" and "bus tie" wherever they appear in the standard.

Response: The SDT believes that events which can result in a single line or line section being fed radially from one end must be analyzed to ensure that Load served from the line can be reliably served from either end regardless of station configuration.

The SDT expanded the existing Table 1 description to include the requirement to study the loss of any generator followed by the loss of a transmission element. The SDT made this decision based on the fact that generator outages are more probable and in many cases have longer outage durations than transmission element outages. The SDT considered a requirement to study any outage of a transmission element followed by a generator outage but decided that this would be very burdensome for a lower probability event and therefore, decided not to add it in Table 1 of the draft standard.

P2 - The tables have been combined and the words "Loss of" have been removed.

The SDT agrees. Event 2 in P2 has been modified for clarity.

Requirement R3.3.2.2 has been deleted in favor of Header note ‘e’ in the Table. Please note that the two tables in the second draft have been reduced to one table in the third draft. Requirements R3.5.1 and R5.4.3.1 have been deleted from the Standard.

Organization	Question 15:	Question 15 Comments:
The "3-phase faults" does not apply to DC lines. The SDT has revised the Table accordingly. P6 - The tables have been combined and the words "Loss of" have been removed. The final draft will have all defined terms capitalized.		
Progress Energy Carolinas	C — Definitely do not support the revised standard	While be believe that in many ways the proposed draft standard represents an improvement of the current standard, we have a number of significant concerns that preclude our endorsement for the proposed standard as currently drafted. These include those discussed in the comments to above questions and the below additional comments.1) In both the Steady State and Stability Tables, Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. 2) The proposed sensitivities create significant amount of additional work for the sole purpose of demonstrating compliance to this standard without any demonstratable benefit towards improving system reliability. While sensitivities should be appropriately considered in studies, this standard should not be overly prescriptive with respect to specific sensitivities or study methodologies.
Response: 1. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in Draft 3 of the Standard provides this clarification. **Footnote #10** – 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 be considered. 2. The SDT agrees with the respondent that the sensitivities evaluated should be based on the individual situations and therefore, the SDT has not required specific sensitivities, but rather, required that at least one sensitivity should be evaluated for an Assessment to be complete.		
Platte River Power	A — Generally	In Tables 1 and 2, Categories P1 and P3, under the column heading "Interruption of Firm Transmission Service Allowed," change the note in the performance box to read "Yes, if transfer is dependent on the outaged Element." (Not just for a DC

Organization	Question 15:	Question 15 Comments:
Authority	support the revised standard	line Element.) This conditional statement applies to most Firm Point-To-Point Transmission Service (Firm PTP) applications where an outaged Element reduces the Transfer Capability of the PTP service if the Element cannot be restored to service after an allowable time frame (30 minutes or so) and the Transfer Capability is reduced to a Prior Outage System Conditions level. This "extended Contingency situation" could cause an interruption or curtailment to the firm service. The interruption and curtailment responses to a Contingency might be different between Firm PTP and Network Integration Transmission Service.
Response: The SDT has removed the "Yes if transfer is dependent on the outaged DC line" comments from the Table to ensure that AC and DC lines are treated equally. The draft standard does not allow interruption of Firm Transmission Service as a System response to Event P1. However, the SDT added Footnotes # 5 and 10 to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service in preparation for the next Contingency will be allowed provided there is no shedding of firm Load. **Footnote 5 -** When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – 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 be considered.		
BCTC	C — Definitely do not support the revised standard	BCTC appreciates the efforts of the SDT to explore ways to improve our planning standards. We understand that some of the proposed enhancements may assist Transmission Planners with justifying the need for system reinforcements. Many areas of our system already meet the proposed improvements, for example, most (but not all) of our 500 kV system already meets the proposed standards for systems above 300 kV. We have planned our system without support from a standard. The proposed changes do not really help us in any way and have a number of undesirable consequences. Consequently, BCTC does not support a number of the proposed additions and is uncertain about supporting some of the other changes. Our concerns are summarized below under headings of System Issues and Study Issues. System Issues:1. BCTC plans, manages and operates 18,000 km of transmission in British Columbia. This includes 5700 km of 500 kV transmission lines. For the BCTC system, the proposed definitions for Consequential Load Loss and Non-consequential Load Loss, specifically that load loss due to RAS/SPS is Non-Consequential Load Loss, will provide no reliability benefits for our 500 kV transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection relative to what we have today. No reinforcements of this 500 kV transmission will be required as a result of these more stringent definitions. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level, primarily in rural areas currently served by radial lines. The possible benefits would be small. There is a very low probability that we would get funding approval for these facilities. For most of our system including most of our backbone 500 kV and local networks in

Organization	Question 15:	Question 15 Comments:
		metropolitan and urban areas BCTC already meets the requirements for these definitions. As noted in our comments at item 3, a portion of the BCTC system above 300 kV cannot meet the proposed P1(A) > 300 kV. We require further clarification of these definitions such as allowing load shedding in local networks. Otherwise, we will not be planning a doable/plausible set of actions, but rather just generating a list of projects that will not be approved. Our resulting subsequent corrective plan will be to use load shedding RAS, which will conflict with the definitions. Order 693 does not require NERC to prohibit load shedding, only clarify the amount and duration of load shedding that is permitted (paragraphs 1795 and 1797). BCTC's concerns can be addressed by including the local network component of Footnote (b) - modify the definition of Consequential Load Loss to permit the use of RAS in local networks (including local networks interconnecting generation), by allowing Non-Consequential Load Loss for local networks in Tables 1 and 2, or by modifying the definition of BES to exempt local networks from the definition of BES. BCTC could also consider a limit on load shedding if the industry would develop one. BCTC raised these issues in our comments on the first draft. The SDT response (page 332) does not address our concerns. We also note FPL comment 7 (page 359) regarding removal of localized load reduction provided in Footnote (b). We do not believe that the SDT has addressed FPL's issue. Unless the local network component of Footnote (b) is included and we can get a clarification to address our concern with P1 (A), the proposed standard is not suitable for the BCTC system and we do not support the standard. 2. Contingency P1 needs to permit curtailment of firm service for flow through firm transmission service to prepare for the next contingency. If it does not, some flow through open access transmission customers may have less ATC available if RAS is not available to meet the new restrictions on the P6 contingency, while this ATC will be available for services sourcing or sinking within the transmission provider's system. P6 allows the use of RAS in response to the second contingency (Event). For firm service originating or sinking in our system, we can use RAS and have many RAS systems already in place. However, for flow throughs it may not be possible to implement RAS or there may be a time delay until RAS can be installed. If RAS cannot be implemented, it would be preferable to provide the firm service and curtail in preparation for the second contingency rather than deny the firm service (or require that the system be built for N-2 capability, which also may not be possible), which is what we will have to do to adhere to the new standard. The result is that flow through transactions will have to use non-firm service while non-flow-through may use exactly the same transmission for firm. Also keep in mind that while P4 and P5 are only those multiple contingencies initiated by a common mode failure, P6 is any two elements not necessarily common mode. Therefore, P6 can be more limiting than P4 or P5. For P4 and P5 contingencies the BCTC system has less dependence on RAS than does the second event of a P6. Consequently P6 will be more limiting on flow throughs than P4 and P5. Order 693 contains direction to NERC to address Footnote (b). Some commenters have taken issue with the SDT interpretation of Order 693 (e.g. FRCC item 2, page 365). Given the different interpretations and the potential for impacts on ATC, we suggest that the SDT review this issue with FERC and find out if what the SDT is proposing is what they really want. Without this change or clarification we do not support the standard. 3. Regarding Q30 in the Comments on First Draft, BCTC believes that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. This relates to our concern above

Organization	Question 15:	Question 15 Comments:
		regarding flow through transactions. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable step to prepare for the next contingency of an AC line. We would ask that the SDT provide further explanation of its response that "many of the transfers over DC lines are automatically curtailed when the DC line is outaged" (page 220). We can do the same with AC lines for transfers sinking or sourcing within our system. Is the SDT assuming that RAS/SPS is used? We agree with the comments of FPL, FRCC, Southern Transmission and Manitoba Hydro (pages 219 and 221) and FPL (page 360, item 11). We disagree with the SDT decision to allow different performance for DC than AC lines. We do not support this element of this standard. 4. Contingency P3 should have the same performance requirement as P6. In two recent CPCN approvals for reinforcements of the BCTC backbone system, approval was granted based on generator contingencies being treated the same as transmission contingencies. We believe it highly unlikely that we would have received funding to approval to meet contingency P3. In our local service areas relying on generation for firm supply and for our bulk system, we consider dependable generator capacity on a case by case basis. We do not arbitrary assume a generator N-1 as a preexisting planning condition. We consider firm generator capability as a sensitivity case, not a planning criteria. We disagree with requiring a generator initial system condition having a more stringent performance requirement than other initial conditions. Without this change we do not support this standard. 5. BCTC is concerned that including the generator runback/tripping requirement in this standard will encourage more use of generator runback and tripping and will make it more difficult to get regulatory approval for transmission reinforcements. If retained, there needs to be a tie into reserves requirements. While we agree with permitting generator runback/tripping, at this time we are unsure about supporting this standard with this permissive requirement included. Study Issues:6. R2.5 and R5.5 on Generating Unit Stability studies are adequately addressed by FAC-001 and 002. Triggering events such as increased output or new existers need to go through our generator interconnection process and be paid for by the customer. In fact, we would not be aware of any of these triggering events unless a request comes from a customer. Without clarification of which generator studies are addressed through FAC-001 first, we do not support this standard. 7. We request that the SDT provide an explanation of why it believes it is important to maintain a distinction between system and generating unit stability studies. 8. Table 1 Steady State Performance lists 6 items above the Planning Events title. Should these be listed below the Planning Events title?
Response: 1. The SDT has added footnote 10 and clarified that for a P1 event, Transmission service could be interrupted as long as all of the Non-Consequential Load continued to be served. This draft does not allow "local network" Load to be shed for a P1 event, however, the conditions that you describe could warrant a regional difference.		

Organization	Question 15:	Question 15 Comments:
Footnote #10 – 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 be considered. 2. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. 3. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally. See footnote #10. 4. The SDT believes that the loss of a generator unit is a much more likely to occur than the loss of other major BES elements and thus the P3 event warrants more stringent performance requirements than the P6 event. The performance requirements for P3 have been clarified by addition of footnote 10 in Revision 3 of the Standard. 5. By a nearly unanimous response the Industry favors manual and automatic generation run-back and tripping as a response to a single or multiple Contingency. The SDT has eliminated the conditions in Sub-requirements R3.5.1, R3.5.2, and R3.5.3 for Contingency events as well as similar conditions in Sub-requirements R5.4.3.1, R5.4.3.2, and R5.4.3.3 for Stability events in the third draft. Accordingly, the SDT has modified Sub-requirement R3.5 for Contingency events and relocated it under Requirement R2.6.1. Likewise, the SDT has modified Sub-requirement R5.4.3 for Stability events and relocated it to become a bullet under R2.6.1. The resource adequacy issues are not directly included in this standard. In addition, with the creation of P3, the SDT has addressed the issue of the reduction of generation resources by treating the loss of one generator unit, followed by System adjustment, as the initial condition for all other single Contingencies. Therefore, the SDT does not believe that generation tripping as a corrective action needs to be tied to resource adequacy issues. Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate Steady State performance violations. Installation or modification of automatic generation tripping as a response to a single or multiple Contingency to mitigate Stability performance violations 6. Both Requirement R2.5 and Requirement R5.5 have been deleted since, in response to industry comments, Generating Unit Stability is no longer separately addressed in the standard. 7. Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis. 8. The SDT has reformatted and combined the two Tables into a single Table for this draft to address these types of problems.		
Manitoba Hydro	C — Definitely do	Manitoba Hydro can not accept the standard due to the requirements imposed on Firm Transmission Service and on facilities >300 kV. The standard would have to allow Firm Transmission Service to be curtailed in situations where Non-

Organization	Question 15:	Question 15 Comments:
	not support the revised standard	consequential Load is not lost. The higher performance requirements for facilities >300 kV are tied to very low probability events, so the enhanced reliability is not worth the cost. TPL-001-1 Other Comment Action Plan: Schedule of Anticipated Actions needs to be revised. - Action 3 shows rev 3 out for ballot in 2Q09. TPL-00101 Purpose: Is the purpose to ?Establish Transmission System planning performance requirements? or to ?Establish planned Transmission System performance requirements? The term ?probable contingencies? is not defined or used in the standard ? use of the term may cause confusion. R7: The TP and PC are required to determine the responsibilities for performing the assessment. Are the responsibilities to be documented as part of the assessment? R8: This requirement should avoid reference to a FERC order as the order does not apply to all entities. The requirement should just require the planner to demonstrate that the assessment was distributed to potentially impacted stakeholders. The last sentence is incomplete.

Response: In response to your comment and those of others in the industry on allowing curtailment of Firm Transmission Service as a System adjustment after an N-1 Contingency, the SDT has added footnotes 5 and 10 to Table 1 - Steady State & Stability Performance.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – 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 be considered.

The schedule has been updated.

The SDT believes the Purpose is accurate as written because it defines planning practices and conditions to be studied. As per A.3, the purpose of Standard TPL-001-1 is to "Establish Transmission System planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies." In this definition, the word probable is left up to the Transmission Planner/Planning Coordinator to determine so that they can set System performance requirements locally based on experience.

R7 (now R6). There is no requirement to document the responsibilities as part of the Assessment but Measure M6 in the new draft clearly states that a document must be produced as evidence that Requirement R6 has been successfully completed. This could be a standalone document or part of the Assessment at the discretion of the responsible entity.

Organization	Question 15:	Question 15 Comments:
R8 (now R7): The SDT believes the addition of the reference to the FERC Order 890 adds clarity to the expectations of the requirement without making the requirements of the Order applicable to all NERC entities. The incomplete sentence has been deleted.		
Los Angeles Department of Water and Power	C — Definitely do not support the revised standard	I do not support the standard as currently written. There are too many requirements that are discriminatory, duplicative, and arbitrary/punitive. The unintended consequence of this standard would be forcing companies and planners to plan the system to take advantage of some requirements that will result in a future system that is less robust (a single line serving multiple radial loads instead of network, for example) if not to entiely discourage any further expansion of the transmission system above 300kV (the discriminatory treatment of two classes without any rational justification).
Response: The SDT believes that the appropriate justifications have been made. The SDT changes made after the first draft were due to industry consensus. The SDT believes that these changes are justified by the various comments received from industry.		
Transmission Agency of Northern California	B — Unsure about supporting the revised standard	- We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before we can give a full approval of this Standard. - There is no mention in the purpose of the Sta
Response: Measures, VSL's and the Implementation Plan have been addressed in the third draft of the standard.		
National Grid	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.

Organization	Question 15:	Question 15 Comments:
		b. This standard does not address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from Standard. g. Put headings on each section to identify requirements of section. h. With respect to R2.2 - Delete "current" from the phrase"current System Peak Load study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.

Organization	Question 15:	Question 15 Comments:
		o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. What is a "current" study?

Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that 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 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. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794, FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0.

Footnote #10 – 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,

Organization	Question 15:	Question 15 Comments:

Facility Ratings in those regions must be considered.

E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment.

F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

H. The SDT believes that the existing language is appropriate.

I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.4.

K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the Contingency.

L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

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.

Organization	Question 15:	Question 15 Comments:

N. The SDT has re-written Requirement R3.3 (now Requirement R3.4) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.4 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 (now R 4.3.2) has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability. These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised Requirement R4.3.3.

Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known."

R. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.

Organization	Question 15:	Question 15 Comments:
Tenaska, Inc.	A — Generally support the revised standard	A few issues that may need some thought include: Are reactive power devices a responsibility of Resource Planners in R13? On the Extreme Events description for local area, what is a load center? Does the loss of a large body of water as a cooling source result in the immediate loss of generation such that it is a contingency which affects steady state, stability, or short circuit studies?
Response: In response to industry comments, the SDT has removed Requirements R9-R14 and thus eliminated the responsibility of a Resource Planner. The SDT believes that a Load center is a location where energy is delivered by Transmission or sub-Transmission Systems to end-use customers. The loss of a large body of water as a cooling source could cause an immediate loss of generation or could only cause some generation reduction. The Transmission Planner or Planning Coordinator would need to analyze their System in order to determine the proper simulation(s).		
Pacific Gas and Electric Co.	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer

Organization	Question 15:	Question 15 Comments:
		curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Public Service Company of New Mexico	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss

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Puget Sound Energy, Inc.	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before PSE can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting

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		performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with "raising the bar". Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms "interruption of firm transmission service", there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what "Firm Transmission Service" means. Two points, 1) the NERC definition states "highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption." The Standard implies anticipation of "unplanned" interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the power flow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is out of service.
Idaho Power	B — Unsure	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures,

Organization	Question 15:	Question 15 Comments:
Company	about supporting the revised standard	VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of “unplanned” interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02)Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption

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SMUD	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before giving a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rata curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of trade offs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular

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Sierra Pacific Power Company / Nevada Power Company	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these

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		definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
Black Hills Corporation	B — Unsure about supporting the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before a full approval of this Standard can be given. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load

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Tucson Electric Power Company	C — Definitely do not support the revised standard	The Standard as presented is clearer, but there are numerous issues that still need resolution. There should be no distinction in voltage classes for allowing or not allowing controlled load shed for applicable events. We support the use of load shed for events at voltages greater than 300 kV where load shed is allowed for the same type of event for voltages below 300 kV. We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ?

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Tri-State G&T	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. ? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. ? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. ? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that

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ColumbiaGrid	A — Generally support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with "raising the bar". Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a

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Southern California Edison	B — Unsure about supporting the revised standard	Our Response is (B) and (C).We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions. We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with “raising the bar”. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level. As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a

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Alberta Electric System Operator	C — Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous identified issues that still need resolution, in addition to the Measures, VSLs, Implementation Plan, etc., before AESO could give a full approval of this Standard. – There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability. – We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.- We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar? for loss of Facilities with operating voltages 300 kV or higher (P2, P4, and P5 in the Performance Tables). We believe there should be no distinction between the voltage classes.-

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		Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what ?Firm Transmission Service? means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product, or firm transfers modeled for the conditions being studied? One way to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table.- In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.
US Bureau of Reclamation	C ? Definitely do not support the revised standard	We agree that the Standard as presented is clearer, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.? There is no mention in the purpose of the Standard about minimizing loss of load for more probable unplanned contingencies. Maybe there needs to be some definition around what is meant by reliability.? We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce. Or, to maintain the same firm power transfer under normal conditions, construction of transmission facilities will be required. Either way, this would impose a much stricter standard than exists today resulting in very costly unnecessary system improvements and invalidate terms of many transmission service contracts that allow for implementation of pro-rate curtailments of firm transmission rights during forced and planned outage conditions.? We disagree with the application of the proposed definitions of Consequential Load Loss and Non-Consequential Load Loss in conjunction with ?raising the bar?. Local Network load should be included in Consequential Load and the loss should be allowed for single contingencies. The TPL standard is to maintain reliability of the BES. Under certain conditions orderly dropping of local network load could limit the spread of the disturbance beyond the local area and allow BES reliability to be maintained. This would minimize the total amount of load loss and allow for quicker load restoration. The proposed definitions for Consequential Load Loss and Non-consequential Load Loss will provide no reliability benefits for

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		high voltage (>300 kV) transmission backbone system providing wholesale open access service and interconnecting to the rest of the western interconnection. Any potential reliability benefits of any additional facilities built to comply with these definitions would be at the local service level.? As mention in comments to Q3 above, some local network customer curtailments or local area load loss has been allowed by local regulatory authorities as long as the overall reliability of the interconnected system was not impacted. This is a result of tradeoffs between providing a higher level of reliability in a local area and the cost and environmental impacts of providing that service. Such tradeoffs are subject to local regulatory authority or contract negotiated between the transmission provider and its transmission customers. Regarding the terms ?interruption of firm transmission service?, there needs be clarification on what Interruption means. Since it is referring to firm transmission service, we would interpret this to mean curtailment needed after a particular contingency and adjustments. There also needs to be clarification on what “Firm Transmission Service” means. Two points, 1) the NERC definition states ?highest quality service offered to customers under a filed rate schedule that anticipates no planned interruption.? The Standard implies anticipation of ?unplanned? interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order 890, or firm transfers modeled for the conditions being studied? One way Comment Form for 2nd Draft of Standard TPL-001-1Assess Transmission Future Needs (Project 2006-02) Page 12 of 12to interpret the intent is the firm transfers being modeled for the conditions in the powerflow to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load if the transfer being modeled is interrupted, then interruption of firm transmission service should also be allowed for P1 through P5 contingencies in the table. In addition, we believe that DC and AC lines should have the same performance requirements with respect to interruption of firm transmission service. We do not understand why interruption of firm service would be an acceptable response to the loss of a single pole of a DC line (i.e. response to the contingency) but not an acceptable response to prepare for the next contingency of an AC line. The transfers over both AC and DC lines can automatically be curtailed when the line is outaged.

Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard.

The NERC standards are based on deterministic principles. Probability is considered in a high level perspective as a means of rationalizing the inclusion of various deterministic events; however it is difficult to discuss probability in this context without creating misunderstandings. The SDT recommends that you review the NERC definition of Adequate Level of Reliability (ALR), which is the reliability goal for all NERC standards. In response to your comment and those of others in the industry, the SDT has proposed differentiating between loss of firm Load and loss of Firm Transmission Service. This differentiation is provided in footnotes 5 and 10 to Table 1 - Steady State & Stability Performance. In the event that loss of Firm Transmission Service is inadequate, the SDT believes that there are alternatives to loss of Load or construction. For example, companies may contract with interruptible Load and shed customers voluntarily.

Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not

Organization	Question 15:	Question 15 Comments:
permitted for single Contingency events. This position was vetted in draft 1 of TPL-001-1 and most stakeholders and 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. Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT. **Footnote #10** – 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 be considered. The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Gainesville Regional Utilities	C — Definitely do not support the revised standard	First, a starting point for the study process (base case) needs to be better defined even if the intent was to allow the TP's & PC's to make the decision. The standard should describe the rules to properly conduct a base case study within each region. This should support any following analysis studies and their finding since you will be starting from the same set of system elements operating at a base condition. Secondly, this standard should focus on what is best for the customer considering 1) the probability of the contingency events, 2) the potential expense to the customer for practically NO improvement in BES reliability, and 3)the extraordinary added burden on the smaller utilities to run additional, no added value studies with documentation to meet an exhausted detailed audit with the potential for penalties probably not proportioned to the utilities revenue stream.
Response: The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a system will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. The SDT has retained the basis of the previous standard and raised the bar in some respects. While the performance requirements must be met, they do not necessarily mandate a solution. Considerable flexibility in Corrective Action Plans allows for economic considerations. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors (including ROW) involved here and is		

Organization	Question 15:	Question 15 Comments:
taking them into consideration in its deliberations.		
Lakeland electric	B — Unsure about supporting the revised standard	Suggested changes listed below to more directly address what I think is the intent of the item: Planning Events: Events that require Transmission system performance requirements to be met. Comment: I think that this suggested revision better defines a Planning Event and how they may be used in a study or assessment. Revision to: Planning Events Planning Events: Simulated events that are modeled to test the Transmission system's ability to meet performance requirements. R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that have occurred in the intervening period and would impact the study area. Comment: the requirement as stated leaves one guessing about the usability of a study that may have included the changes that occurred in the intervening period. Changes that were studied but not implemented could also invalidate a study they were included in. Revision to R2.6.2R2.6.2. For steady state, short circuit, Generating Plant Stability, or System Stability analysis: the study shall not include any material changes, such as, generation or Transmission additions/removals, or topology changes that were not included in the original study but have occurred in the intervening period and would impact the study area results.
Response: The SDT did not incorporate the commenter's suggested change and the Planning Event definition remains the same as in Draft 2. The SDT believes the stated definition more correctly indicates the intent that for Planning Events the performance requirements must be met, not simply that simulations need to be completed to indicate if the performance requirements are met or not. The SDT does not agree with your comment and believes that the cancellation of a planned Facility that was included in prior models would be a material change to the network model and therefore would not allow the past study to support the Planning Assessment. The key phrase within the requirement is "the study", therefore, the intent is model simulation changes and not limited only to real physical System changes. Therefore, the SDT believes the instance raised by the commenter is adequately covered.		
JEA	C — Definitely do not support the revised standard	The inability to curtail Firm Transmission Service under P6 assessments in preparation for the next N-1 event. Also, under P1 and lower probability contingency events, JEA recommends a standard requirement that allows for the loss of Non-Consequential load during short term periods (suggest allowing up to 3 year minimum) where the system load growth has caused post-contingency remedial action plans to not be completely affective in bringing the Facility(ies) within normal operating limits. As a specific theoretical example, lets say a 10 year assessment shows load growth causing this situation in year 5, but in year 7 generators are added to the area of concern and the issue is resolved, but in year 6, Non-consequential load is required to be shed, do we still need to propose a capital improvement project?
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

Organization	Question 15:	Question 15 Comments:
necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – 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 be considered. The proposed standard does not require capital improvements, but it does require the performance metrics to be achieved. Certainly there will be circumstances where the addition of Transmission or generation facilities may be the only practical solution. For the specific example that you described, if there were no acceptable Operating Procedures to bridge the time period before the generator comes on line, entering into interruptible Load contracts would be another option. The standard does not preclude such actions.		
PacifiCorp	A — Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard. We believe that with the loss of the first N-1 in P6, curtailment of firm transmission service or firm transfers should be allowed as part of system adjustment in preparation for the next N-1. This should be added to R3.3.2.2. Otherwise, the power transfer under normal condition (before the first N-1) will have to be significantly curtailed in anticipation for meeting performance requirements after N-1-1. This will unnecessarily impede commerce.
Response: Measures, VSL's, and the Implementation Plan will be addressed in the next draft of the standard. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the Table. **Footnote #10** – 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 be considered.		
ITC Holdings: ITC, METC, ITC Midwest	B — Unsure about supporting the revised standard	ITC and ITC Midwest biggest concerns are some missed opportunities to "raise the bar". We believe the draft standard is a significant improvement over existing standards which are largely fill-in-the-blank. However, we have some concerns regarding some of the language wherein CAPs are not required, even though a performance requirement has been violated. For example, providing for a bare minimum sensitivity study and not requiring a CAP based on a performance violation may increase operational awareness but does not ?raise the bar? or improve transmission performance. Allowing for non-consequential load loss following a shutdown and contingency might be an acceptable real time operating

Organization	Question 15:	Question 15 Comments:
		procedure but is not a significant advancement on a transmission planning basis. Frequently, operating procedures like this should lead to a planning solution, particularly above 300kV
Response: The SDT translated the existing TPL standards, added clarity, and "raised the bar" in areas where the SDT believes are merited. Even though the existing TPL standards do not address sensitivities, the SDT has added a requirement to complete at least one additional sensitivity. The SDT believes that it is important and valuable for the Transmission Planner and Planning Coordinator to run significant sensitivities and share the results with their neighbors. The SDT did not limit when Operating Procedures, other than Non-Consequential Load loss, could be utilized. The SDT believes that it is important for the Transmission Planner and Planning Coordinator to determine when an Operating Procedure can be utilized and when new Facilities need to be constructed. A Corrective Action Plan is required for all performance violations of all Planning Events in Table 1, except, as you have noted for sensitivity study performance violations. The SDT concurred with the FERC orders that sensitivity study results do not necessarily result in a Corrective Action Plan. From paragraph 1704 of Order 693: "The Commission notes that it is not the purpose of sensitivity studies to identify remedial actions, but, as stated in the NOPR, if different scenarios that lead to criteria violations are probable they require mitigation plans………. In any case, we are not requiring the construction of additional facilities." While the standard does not "require" a Corrective Action Plan, it does not preclude a Corrective Action Plan, particularly if it meets FERC requirements for a "mitigation" plan if the Planning Events are "probable". The majority of the SDT, based on industry comments, did not feel that Non-Consequential Load loss should be precluded from N-1-1 events. A Corrective Action Plan is not required if Non-Consequential Load loss is allowed under local criteria but the standard does not prevent local criteria from prohibiting Non-Consequential Load loss for N-1-1 events.		
Hydro-Quebec Transenergie (HQT)	C — Definitely do not support the revised standard	This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are:? Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.? Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems.? This comment form did not allow for the following items to be addressed:? a. Definition of the Long-Term Planning Horizon. The planning horizon, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement.? b. Definition of Planning Coordinator is part of the NERC Functional Model, For consistency it should be removed from the Standard.? c. We propose that the Standard be subdivided by subjects into 4 different Standards : ? TPL-001-1: Modeling and System Assessment (R1, R2, R9 to R14)? TPL-002-1: Short circuit and Steady State Performance (R3, R4)? TPL-003-1: Stability Performance (R5)? TPL-004-1: Coordination (R6, R7, R8)? If the previous proposition is not retained, at least the Standard

Organization	Question 15:	Question 15 Comments:
		Requirements should be organized by topics (Modeling, Assessment, Coordination, etc.) and headings put on each section to identify requirements of section. Add headings to the tops of the subsequent pages in the performance tables. Headings only appear on the first page at the beginning of the Table.? d. With respect to R2.2 - Delete "current" from the phrase" current System Peak Load study" and replace "study" with "assessment."? e. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment?? f. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R 3.3.3 and R3.4. It is unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.? g. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state.? h. Remove R3.2.2 - Relay loadability is addressed in PRC-023 standard.? i. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard.? j. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies.? k. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. ? l. The provisions of Section R.5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how these devices are treated in the simulation.? m. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. ? n. In both Table 1 and Table 2, note 3, "variable frequency transformers" should be removed from the last sentence. A new sentence should be added for reference voltage as it applies to "variable frequency transformers" and "back-to-back" facilities.

Organization	Question 15:	Question 15 Comments:

Response: Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that that interruption of Non-Consequential Load is not permitted for single Contingency events. This position was vetted in draft 1 of the TPL-001-1 and most stakeholders and 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.

A. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the planning event until the planned Facilities can be completed. This information needs to be included in the Assessment.

B. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

C. The SDT agrees with FERC Order 693 in aggregating all of the planning requirements into a single standard. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, this version combined Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed.

D. The SDT believes that the existing language is appropriate. No change made.

E The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

F. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT agrees with your interpretation that it does not require evaluation of all single Contingencies. Rather, the SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

G. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators will be able to operate or trip off following the Contingency.

H. The SDT believes that relay load limits or loadability needs to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level which may add to the existing Contingency and perhaps, result in an unbounded cascading event. No change made.

<table>
<tr><th>Organization</th><th>Question 15:</th><th>Question 15 Comments:</th></tr>
<tr><td colspan="3">I. By definition, Consequential Load Loss is allowed. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.~~-~~8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

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.

J. The SDT agrees that the rationale should be for all Planning Events but not for Extreme Events.

K. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~C~~ontingencies in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4 For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

L. Requirement R5.3 (now R4.3.2) has been modified to address simulation of how generators perform under conditions being studied. "Other equipment" is addressed in Requirement R5.4.

R4.3.2 ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~

M. While planned outages are addressed in the operating horizon, it is important that a Transmission Planner review the ability of its System to accommodate planned (maintenance) outages. Additionally, any specific known Facility outages need to be appropriately modeled for the planning horizon studied.

N. Tables 1 and 2 have been combined into one table for the next posting. The SDT believes that it has adequately addressed "variable frequency transformers" as well as "back-to-back" facilities by including it in the same note as other transformers (Note #3).</td></tr>
<tr><td>Progress Energy Florida, Inc.</td><td>C — Definitely do not support the revised</td><td>PEF considers the draft TPL Standard in its present state to be infeasible, unnecessary, burdensome and inferior to the existing Standards. The basic approach to equate reliability of the BES to whether or not Firm Transmission Service and/or Non-Consequential Load Loss can be sustained is an erroneous approach, is not justifiable, infringes upon</td></tr>
</table>

Organization	Question 15:	Question 15 Comments:
	standard	regulation already in place as part of dealings with the Florida Public Service Commission (PSC), and infringes upon requirements in the OATT. Given the numerous concerns PEF has with the revised draft Standard, expounding on those concerns requires extensive documentation. We therefore cannot reduce our concerns down to a single issue, nor can we single out a single requirement or set of requirements as the top concern, other than to say that the entire Standard development process either needs to be discontinued or the SDT should provide detail as to how much consideration would be given to transmission systems with historically excellent reliability via a variance process. The following is a list of PEF’s primary concerns with the revised draft Standard and explanation as to why the Standard development process should be discontinued: 1. PEF has planned to, and demonstrated compliance with, the existing TPL Standards for several years now. PEF is intimately familiar with the existing Standards, and has done an excellent job in planning the PEF system, in conjunction with the other Transmission Owner members of FRCC, non-FRCC adjacent Transmission Owners, and all requestors of Transmission or Generator Interconnection Service using the existing TPL Standards. PEF thus believes that history has shown, particularly within the realm of PEF’s Transmission Planning boundaries, that the existing four TPL Standards are not inadequate or inferior in any way. Statements in recent months alluding to the existing Standards? inferiority, confusing language or language subject to opposing interpretations, do not hold up when applied to the PEF and FRCC systems. PEF thus does not believe the Standards require modification. 2. PEF, through its aforementioned participation with FRCC and through its interaction and compliance with regulation by the Florida PSC, has historically demonstrated excellent Transmission Reliability, and can provide documentation to that effect through FRCC and Florida PSC channels. PEF therefore again asserts that modification or increased stringency in the TPL Standards is not merited. 3. The development of TPL-001-1 stems from a fundamental misinterpretation of the intent of FERC Order 693. NERC for the most part, rather than “clarify” or “consider” various matters raised by FERC, chose to accept all suggestions. Specifically, PEF notes the following misinterpretations regarding Order 693:a) In Paragraph 1692, the Commission agreed with one particular utility’s assertion that integrating the four existing TPL Standards into a single standard would be an improvement, and directed NERC to “consider” this. NERC, rather than considering this, formed the SDT, which appears to have spent little considering the issue but rather have deemed it a foregone conclusion that the four existing TPL standards must be abolished and a new standard must be written. b) In Paragraphs 1694 and 1706, the Commission recognizes the significant differences in the various transmission systems, and the impossibility of developing a standardized list of “sensitivities” of critical operating conditions that every Transmission Planner and Planning Coordinator must analyze, regardless of their applicability. The Commission therefore stated that it is reasonable for planning entities to have a means to identify an appropriate range of critical operating conditions, without having to anticipate ?every conceivable critical operating condition.? They furthermore state that their conclusion on the whole matter is that ?only those deemed to be significant need to be assessed?. PEF agrees, and thus is perplexed by the erroneous developments in Requirements R2.4, R2.5, R5.4, R5.5, R2.1.3 and R2.1.4. PEF has

Organization	Question 15:	Question 15 Comments:
		addressed the inadequacies of these Requirements in the answers to Questions 2 and 10. c) In Paragraph 1704, the Commission, amongst other statements, states that they ?are not requiring the construction of additional facilities?. This general statement made by the Commission is demonstrated to be untrue upon examining the realities of the Standard development process. FERC, by directing NERC to consider various clarifications and/or improvements to the TPL Standards, has set in motion a process which will prohibit either Interruption of Firm Transmission Service or the loss of Non-Consequential Load for various outage scenarios, effectively necessitating the construction of redundant facilities. FERC's statement conflicts with the ongoing process in a major way, and PEF respectfully requests that the SDT confer with appropriate FERC personnel to get clarification on this matter. d) In Paragraph 1725, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy. PEF does not disagree with the specifics of analyzing events with respect to spare equipment, except to the extent that the Commission appears to think that such analysis is not adequately covered in the existing TPL Standards. PEF believes that the existing TPL Standards adequately address this issue and all other issues pertaining to the planning of a transmission system. Furthermore, the process is to be followed ?consistent with the entity's spare equipment strategy?, thus deferring to the processes and judgment of the individual Transmission Owners, which calls into question the need to include it in the draft Standard. For additional discussion on this issue, see the answer to Question 5 with regard to Requirement R11. e) In Paragraph 1782, PG&E points out the contradiction that FERC creates in Paragraph 1796 by directing NERC to remove the 2nd sentence of footnote (b). The contradiction also involves key statements made by the Commission in Paragraph 1788. For a more detailed explanation of this contradiction, see the answer to Question 11. f) Paragraph 1794 is part of the Commission Determination section. The Commission states its belief that no TPL Standard should allow an entity to plan for the loss of non-consequential load in the event of a single contingency. The Commission then directs NERC to "clarify the Reliability Standard.", and furthermore state that any Transmission Planners or Planning Coordinators seeking to plan for the loss of non-consequential load in the event of a single contingency can make their comments known through a) filing comments in the standards development process, or b) filing for a regional difference for case-specific circumstances. PEF points out that the Commission merely stated their belief and directed NERC to clarify the Standard. They did not order NERC to change the Standard to reflect its beliefs. NERC, while having the leeway to question FERC's approach in this Paragraph, did not question the approach, but rather deferred to the suggestion in Paragraph 1794 (as well as nearly every other suggestion or request for clarification) that FERC made. PEF is concerned that NERC and the SDT appear to be limiting the extent to which they question or make suggestions to FERC. PEF at present will take the approach of stating the prudency and need to plan for the curtailment of Firm Transmission Service and loss of non-consequential load in the event of a single contingency through the comments process. PEF, however, reserves the right to consider the variance approach or legal approaches, depending on further iterations in the development of the Standard. g) In Paragraph 1795, "The Commission" suggests that the ERO consider developing a ceiling on the amount and duration

Organization	Question 15:	Question 15 Comments:
		of consequential load loss that will be acceptable. If the ERO determines that such a ceiling is appropriate, it should be developed through the ERO's Reliability Standards development process.? To this effect, the SDT drafted Requirement R.3.3.2.1, which at present states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? PEF asserts that this issue is under the jurisdiction of the State Public Service Commissions, who are already doing an excellent job in regulating Consequential Load Loss as part of SAIDI/CMI requirements. FERC and NERC are overstepping their bounds of jurisdiction by attempting to essentially ?double-regulate? an issue that is already adequately regulated via the States. PEF furthermore objects to Requirement R.3.3.2.1 on the grounds that duration of events cannot be estimated with any reasonable degree of accuracy. To handle the challenges of this issue by stating a long-duration worst-case scenario for each outage would be inaccurate, and would tend to foster needless scrutiny and concern on any and all outages associated with Consequential Load Loss. h) In Paragraph 1796, "The Commission" directs the ERO to modify the second sentence of footnote (b) to clarify that manual system adjustments other than shedding of firm load or curtailment of firm transfers are permitted to return the system to a normal operating state after the first contingency, provided these adjustment can be accomplished within the time period allowed by the short term or emergency ratings.? The Commission directed the ERO only to make modifications on the 2nd sentence of footnote (b). The SDT in the draft TPL Standard has eliminated footnote (b) altogether. PEF is surprised and disappointed at the response by FERC to PG&E's very correct assertion that eliminating the allowance of shedding of firm load or curtailment of firm transfers from footnote (b) contradicts the allowance made in footnote (c) regarding C.3 events. FERC's only response was to state that ?manual adjustments referred to in both cases [i.e. Category B and Category C.3 events] apply after the first N-1 contingency?. The fallacy of this statement is that shedding of firm load or curtailment of firm transfers is allowed by footnote (c) for C.3 events, and that every Category B event is by default the first part of a Category C.3 event. PEF asserts that FERC, and consequently the NERC SDT, has created a draft Standard that contradicts direction and suggestion in Order 693 regarding this issue. PEF furthermore asserts that curtailment of Firm Transmission Service or Non-Consequential Load are not valid benchmarks for assessing the reliability of the BES. For additional comments on this issue, see the answer to Question 11. i) Regarding Paragraph 1833, the paragraph in its entirety states: ?MidAmerican states that it supports the proposal to modify TPL-004-0 to require identification of options for reducing the probability or impacts of extreme events that cause cascading. Accordingly, for the reasons cited in the NOPR, the Commission directs the ERO to modify the Reliability Standard to make this modification to the Reliability Standard.? PEF does not understand what FERC has directed on this matter. Furthermore, PEF does not understand the meaning or requirements behind the entire ?Extreme Events? section in the draft Standard, which appears to have resulted from the direction in this particular Paragraph. FERC wants NERC to modify the Standard to ?require identification of options for reducing the probability or impacts of extreme events that cause cascading.? This statement is vague, confusing and does not appear to mandate anything. PEF therefore requests that language in TPL-001-1 to this effect be removed. Furthermore, in Paragraph 1834, the Commission, regarding its preference to expand TPL-004-0 to include analysis of more events such as hurricanes, ice storms, successful cyber

Organization	Question 15:	Question 15 Comments:
		attacks, etc., directs NERC to ?expand the list of events with examples of such events identified above.? This request, similar to Paragraph 1833, does not appear to direct NERC to make specific directions in a Standard. If it was FERC's intent that TPL-004 or its successor be modified to include some or all of FERC's suggested events, and to expand the list further, PEF has many concerns concerning this. The direction in Paragraph 1834 has resulted in the aforementioned Extreme Events section, which contains a note 1 referring to Requirement R3.4. PEF has multiple questions and concerns with the language in this Requirement. The Requirement as worded appears to mandate that Transmission Planners and Planning Coordinators must find the most severe Extreme Event scenarios that can be conceived. Such wording would define any reasonable limit as to which Extreme Events are likely and worthy of analysis, and which are not. Furthermore, many of the events suggested by FERC, such as loss of a large gas pipeline, wildfires, hurricanes, tornadoes, cyber attacks, etc., cannot reasonably be studied. To make any assessment of these events that even approached a level of thoroughness is infeasible, and furthermore has no significant benefit. PEF requests that the SDT point out to FERC that these events cannot be studied, and therefore need to be excluded from any TPL Standard. 4. The main approach of the draft TPL Standard consists of whether to allow or disallow load loss for certain outage scenarios (the most problematic Event categories being P1, P2.2, P2.3, P3, P4, P5 and P6), an approach to which PEF is opposed, and furthermore believes that level of service to retail load is not an issue that NERC/FERC should be regulating. The local utility commissions (the Florida PSC, etc.) have already set in place processes for reviewing/approving the level of transmission built to support the level of service to load, and thus FERC and NERC inappropriately attempt to regulate an issue which the States already adequately regulate. PEF can, and has demonstrated in its internal planning assessments and in assessments performed with FRCC that load curtailment and/or Firm Transmission Service curtailment do not adversely impact the reliability of the BES. In fact, certain post-contingency scenarios can be shown to demonstrate that such curtailments actually promote reliability and a speedier, safer, more efficient recovery of the BES after an event. 5. Several Event categories as presently defined in the draft TPL Standard present outage scenarios on the PEF system for which implementation of redundant transmission facilities would be required, at an exorbitant cost to ratepayers. The redundancy requirements at PEF's 500 kV, 230 kV and 115 kV Substations are numerous, and have not yet been comprehensively quantified, although this analysis is underway. One scenario for which PEF is already certain that redundancy of the 500 kV system would be required is the apparent disallowance of curtailment of Firm Transmission Service or Non-Consequential Load as part of ?System Adjustments? in between the two events of P6. PEF again would point out that no definition of ?System Adjustments? exists at present, and the SDT therefore must define it if compliance is expected. Be that as it may, PEF's 500 kV redundancy projects would clearly cost many billions of dollars, with extremely little benefit. PEF would furthermore point out that this is but one example requiring unnecessary Transmission upgrades, and that further analysis will potentially reveal several more Event categories in Tables 1 and 2 for which additional cost-prohibitive and unneeded projects would be mandated. 6. PEF is surprised and disappointed that neither FERC nor NERC have accepted any responsibility to alert the public or the State and local governments to this process. The public have not been involved in the development of the draft

Organization	Question 15:	Question 15 Comments:
		standard, nor have they been informed that they would bear the financial impact of the increased stringency. In fact, The SDT on p. 369 of the 1st draft Comments Document has stated that ?This is a performance based reliability standard and does not and should not consider economics.? PEF considers this statement to be reckless and irresponsible, and does not accept FERC's and NERC's apparent position that they have no responsibility in this matter. The fact that the draft Standard and FERC Order 693 can be downloaded by anyone from FERC's and NERC's websites does not constitute a sufficient good-faith notice of this process to the public. PEF requests that FERC and NERC specifically address this issue by explaining their failure to involve and inform the public. Assigning this responsibility to each Transmission Planner and Planning Coordinator is not acceptable. FERC and NERC have set this process in motion, and as creators of the process owe an explanation to those who would "foot the bill" for the process. 7. The low voltage threshold of jurisdiction of the draft Standard, previously defined in NERC's definition of the BES as 100 kV, is not specified in the draft Standard. This is a significant misstep by NERC in that a change to NERC's Glossary Definition of the BES, which would ostensibly be done outside the boundaries of this Standard, could profoundly change the requirement for complying with TPL-001-1 without changing a single word of the Standard. PEF is particularly concerned that this Standard must never have jurisdiction over local load-serving transmission systems, regardless of voltage. Any TPL Standard, existing or future, must focus on the reliability of the BES, i.e. the bulk grid, NOT the local load-serving portions of the transmission system. The draft Standard at present does not address this issue at all and leaves Transmission Planners and Planning Coordinators vulnerable to non-compliance with a mere change in the wording of a Definition outside of the Standard. 8. PEF strenuously objects to the allowance of interruption of Firm Transmission Service in Events P1 and P3 for DC lines, while disallowing the same for AC lines. PEF asserts that the determination should be "Yes" for both, and that disallowance for AC lines a) puts DC systems into an elite class of transmission for no explicable reason and b) encourages owners of AC Transmission Systems to replace them with DC, cost concerns notwithstanding. Furthermore, this differentiation fails to recognize or give consideration to the fact that AC systems support Firm Transmission Service; some areas of the AC transmission system carry significant amounts of Firm Transmission Service, and thus a "No" determination for P1 and P3 essentially mandates either implementing redundancy for those parts of the AC system carrying significant amounts of Firm Transmission Service, or severely curtailing Firm Transmission Service on the existing AC systems.

Response: The SAR for this standard recognized FERC orders which indicated a need to "raise the bar" for the industry. The SDT is attempting to do this in a reasonable fashion. There is significant flexibility in the Corrective Action Plans allowed for any additional performance requirements which must be met. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

1 & 2. Industry consensus, through approval of the SAR, is that revision of the existing TPL standards is appropriate.

3A. The SDT and industry consensus, at this point in the development process, is that consolidation in a single standard is the best course of action. The SDT did not start out with a preconceived idea that there should only be one TPL standard. The SDT started the drafting process by reviewing all of the available

Organization	Question 15:	Question 15 Comments:
		documents. This included the existing TPL standards, the SAR, FERC Order 693, and other NERC documents. After reviewing this material, the SDT determined that the majority of the language in the individual standards was in all four of the standards. After much discussion, the SDT determined that the industry would be better served with a single standard instead of staying with four individual standards. B. Please see the responses provided in questions 2 and 10. C. The revised TPL-001-1 standard itself does not require construction of additional Facilities although that may be a consequence of application of the standard. Additional operating guides or changes in dispatch are other possible consequences. Footnotes 5 and 10 have been added that provide further clarification regarding interruption of Firm Transmission Service. FERC staff has been available to the SDT for consultation throughout the process. **Footnote 5** - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed. **Footnote #10** – 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 be considered. D The SDT has removed Requirement R11 from the proposed standard and Requirement R2.1.4 has been included to help clarify the spare equipment strategy issue. **R2.1.4** 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 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 due to the unavailability of the long lead time equipment. E. Please see response to your comments on question 11. F. FERC direction provided in Order 693, SDT expertise, and industry input are all being considered in development of the standard. G. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **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. H. The SDT is being responsive to FERC direction in paragraph 1796 and agrees that clarification regarding Non-Consequential Load Loss and Firm Transmission Service requirements is necessary. Table 1 specifies the specific events when Loss of Non-Consequential Load is allowed. Footnotes #5 & 10 have been added to the end of Table 1 to explain Firm Transmission Service requirements. Also, please see response to your comments on question 11. I The SDT believes that the requirement to study Extreme Events in the existing TPL-004-0 must remain in this standard. The SDT has not expanded the number of Extreme Events that must be studied but rather gave examples of how the events may occur. The only significant change in the analysis of Extreme

Organization	Question 15:	Question 15 Comments:

Events is the new requirement for the Transmission Planner or Planning Coordinator to evaluate whether there are cost effective ways to reduce the likelihood or the impact of a particular event and document those findings. The SDT believes that this is a very reasonable approach to ensuring that these major events, even with a small probability, are reviewed and prudent decisions are made.

4. The issues raised on NERC/FERC regulations are beyond the scope of the SDT. However, changes have been made to the 3rd draft of the standard to further clarify the SDT's position on curtailments and service to Loads. Also, Load curtailments are allowed if those customers have signed an Interruptible Load contract arrangement.

Footnote 5 - the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – 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 be considered.

5. The SDT has made the following changes to address the concerns raised by you and others: 1) Added Header note 'e' to the table to show that System adjustments can be made following a single Contingency event, in preparation for the next event; 2) Added footnote 5 to address conditional firm issues, and 3) Added footnote 10 to address re-dispatching resources while continuing to serve firm Load.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

Footnote 5 - When the conditions and/or event(s) being studied form the basis for conditional Firm Transmission Service, curtailment of that conditional Firm Transmission Service is allowed.

Footnote #10 – 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 be considered.

6. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development work. This is an open, transparent process which has been approved by FERC. Any member of the public is free to participate and/or comment. State regulators are included in the process (Segment 9) and comments are welcome from them just as they are from any other segment of the public or industry. Comments are frequently received from state agencies during the lifetime of a project and two regulatory agencies did provide comments on the second posting. As for the comments on economics, it was not reckless but a statement of fact. However, costs are being considered as should be evident by the questions raised (Q12 thru Q14) in the second posting. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations.

Organization	Question 15:	Question 15 Comments:
7. Revisions to definitions in the NERC Glossary of Terms must be approved in accordance with the standards process and issues with application to existing standards would be considered. In addition, each Regional Entity has the ability to establish its own unique definition of the BES. 8 The SDT has removed this differentiation in the Table such that AC and DC lines will be treated equally.		
Lafayette Utilities System	C — Definitely do not support the revised standard	Lafayette's single biggest concern is that the second draft version of TPL-001 imposes performance requirements that are less stringent than those imposed in the previous draft. As the SDT stated in its response to comments on Draft 1: ?The SDT modified the performance requirements relative to Non-Consequential Loss of Load and revised Tables 1 & 2 to add greater detail and provide for more situations where it is acceptable to lose Non-Consequential Load.? This ?watering down? of the standard appears to result from complaints about the costs that certain commenting parties claimed would be necessary to achieve compliance with the performance requirements set forth in Draft 1. This is evident from the SDT's statement in the foreword to the comments form for Draft 2 that the SDT has ?attempted to adjust and clarify the proposed requirements and performance in light of these initial comments,? and that the SDT needs additional information about cost and other compliance issues so that it can ?make more adjustments as appropriate.? Lafayette questions whether it is appropriate for the SDT to shape the performance standards to alleviate certain commenters? cost concerns. The SDT should be focused on developing performance requirements that are judged to be optimal from the standpoint of protecting reliability consistent with sound engineering and planning. Striking a balance between reliability and cost is a policy determination for which responsibility lies elsewhere than in the SDT. Claims that the standards would impose excessive costs are more properly addressed to FERC when the revised TPL-001 is filed for approval because Congress assigned to FERC the responsibility to make judgments of this sort. The SDT should not be ?adjusting? (that is, watering down) the performance requirements in response to transmission owner arguments about the costs of compliance. The dilution of the performance requirements is manifest in a number of elements contained in the proposed draft, including (but not limited to) the following: a) Table 1 (Steady State Performance) would permit the interruption of Firm Transmission Service and the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. In Order 693 (at paragraph 1794), however, FERC emphasized that loss of Non-Consequential Load in single contingency situations is not permissible. b) Adopting less stringent performance requirements for loss of elements below 300kV may be discriminatory. Most wholesale customer loads are served from delivery facilities that operate at voltages lower than 300kV. The outage of facilities operating at less than 300kV therefore may encompass 100% of a wholesale customer's load, while it is likely to impact a much smaller portion of the total load served by the owner of the affected transmission facilities. Therefore, adopting less stringent performance requirements for facilities operating at less than 300kV would impose a disproportionate burden on affected wholesale customers, as compared to the transmission owner. c) In addition to its potentially discriminatory effect, the notion of imposing difference performance standards based on operating voltage would incent transmission owners to scrimp on needed improvements to lower voltage facilities. Presumably, the distinction originates from a belief that outages on 300kV and lower facilities will have less impact on the

Organization	Question 15:	Question 15 Comments:
		Bulk Electric System. As the August 2003 blackout demonstrated, however, disruptions on lower voltage circuits can cause real and reactive power flow fluctuations across, and eventual separation of, higher-voltage networks. d) Regarding the SDT's elimination of the requirement to re-test cases to ascertain the efficacy of additions included in a Corrective Action Plan (sub-requirement 2.7.2 in Draft 1), it is unclear why this requirement was deleted since very few commenters complained that it would be burdensome. It is hard to see how such a re-testing obligation would impose a significant burden, at least insofar as the steady state analysis is concerned. Eliminating the re-testing requirement seems likely to provide minimal savings, but could be important to verifying that appropriate Corrective Action Plan decisions are made.
Response: There are no intentions by the SDT to "water down" reliability. In fact the SDT has raised the bar in many places; e.g., above 300 kV requirements. Resources and expenditures versus adequate level of reliability are being given due consideration throughout the process and will ultimately be determined by the industry through the ballot process. a Table 1 does *not* permit the interruption of Firm Transmission Service or the loss of Non-Consequential Load in three P1 (Single Contingency) scenarios involving AC lines. b & c. The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. d. The retesting of the cases was deleted due to the SDT believing that this requirement was too burdensome; however, any utility may exceed the requirements listed and perform this retesting if they so desire.		
Arizona Public Service Co.	A —Generally support the revised standard	We generally agree with the Standard as presented so far, but there are numerous issues that still need resolution, Measures, VSLs, Implementation Plan, etc., before WECC can give a full approval of this Standard.
Compliance Elements Development Resource Pool (CEDRP)		With regard to Violation Severity Levels for this standard, the CEDRP doesn't believe the version that has be posted for comment can be commented on from a VSL perspective for two reasons 1) it does not have any measures listed and 2) there are so many "sub-requirements" the VSLs would be quite unmanageable, unless each sub-requirement is of equal importance to fulfilling the objective of the standard. Because there are no measures we can't achieve any insight into importance. The SDT may want to consider trimming the standard down to its most basic elements and providing the details (sub-requirements) in a reference document.

Organization	Question 15:	Question 15 Comments:
Response: Measures, VSL's, and the Implementation plan will be addressed in the next draft of the standard.		
Ameren	C — Definitely do not support the revised standard	From an engineering perspective, the biggest concerns are the additional requirements, including prescribed sensitivity studies, associated with R2 for both steady-state and stability scenarios. We believe that we already cover the needs of our system with the existing NERC standards and Ameren Transmission Planning Criteria & Guidelines. The additional analyses proposed by the revised standard are not warranted and any upgrades indentified by the additional analyses will not provide any significant increase in system reliability. For 2008 compliance, Ameren performed the following steady-state contingency analyses on each of four near-term models and one long-term model:617 Category B single contingencies involving lines and transformers.30 Category B single contingencies involving generators 50 MW and above.1699 Category B single branch outages.135 Category C-1 bus faults. 260 Category C-2 breaker failures.112,575 Category C-3 double contingencies involving lines and transformers.18,510 Category C3 contingencies involving 617 lines and transformers and 30 generating units.73 Category C-5 double-circuit tower outages. For 2008 compliance, Ameren performed 496 stability scenarios of four near-term models and one long-term model: Assuming that we can acquire the qualified manpower, which is presently not available, we estimate that proposed new requirements will increase our compliance activity time by approximately 24 man-months or 2 man-years in a six-month window (January-June) to produce the same quality studies that we produce now. Consequently, we view these proposed additional study efforts as excessively burdensome. Further, we do not see how the additional study work and documentation required by the proposed standard will lead to any significant improvements in reliability. Additional comments: The question of expected Consequential Load Loss magnitude and duration, as specified in R3.3.2.1, is not germane to the reliability of the Bulk Electric System, and is a matter for Distribution Planners and local regulatory authority and is not needed in this reliability standard.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. The SDT has reviewed the study work required to comply with the proposed standard as compared to the existing TPL standards. The SDT believes that we have added some additional study work and asked a question about the additional man-hours required to complete any new analysis. However, after this review, the SDT still believes that the requirements for sensitivity studies must remain to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704 of Order 693) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. **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.		

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<tr><th>Organization</th><th>Question 15:</th><th>Question 15 Comments:</th></tr>
<tr><td>City of Tallahassee, FL</td><td>C — Definitely do not support the revised standard</td><td>The requirement regarding non-interruption of firm transmission service in the steady state performance table for Category P1 events does not properly take into consideration the flexibility necessary for utilities with limited interconnections or interconnections with limited transfer capability. This flexibility, which currently exists in the TPL-001 standard (footnote b in the table), allows a utility to curtail firm transactions to prepare for the next contingency. As drafted, in the circumstance where the single element outage in Category P1 was a tie line, even if this line were critical to supporting the transaction (or were required to be in service by the terms of the power contract), interruption of firm service would be a violation of the proposed standard even though such interruption would be either required or appropriate to ensure the reliability of the bulk electric system. For utilities where tie line capacity is constrained or limited, this requirement for Category P1 will require substantial investment in duplicate facilities to ensure that firm transfers would not be interrupted, and the cost of that investment would likely not offer ratepayers a commensurate benefit (presuming such a duplicate facility could even be sited and permitted).For utilities with just a few large generating units (such as a small municipal utility), the requirements for Category P3 in Table 1 set a threshold for compliance that may not be achievable without substantial investment in additional/duplicate transmission facilities and possibly generating units. The concern relates to the restriction about limiting interruption of firm transmission service or non-consequential load following a G-1/N-1 event; the particular scenario is outlined in the bullets below:? Presume a utility with only two large units and some small gas turbines? Under P3, one of these large units is forced out of service? Reserves are called for and delivered along with replacement power using available import capability? Then presume that the N-1 outage in P3 is a major tie line that is critical to the support of the firm power imports? Under the proposed standard, the utility would be unable to curtail the firm purchase or shed any non-consequential load and remain compliant, even though there would be a significant generation/load imbalance & the appropriate response for the reliability of the grid in the region would be to interrupt the transaction and possibly shed load.The flexibility afforded in the existing TPL-001 standard would in fact allow the utility to respond to this event in a more appropriate way while avoiding a very expensive expansion/duplication of facilities (notwithstanding the considerable challenges that the utility would face for siting and permitting of the necessary facilities).</td></tr>
<tr><td colspan="3">Response: The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load in lieu of system upgrades in the scenario described.

Footnote #10 – 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 be considered.</td></tr>
<tr><td>Florida Power and Light</td><td>C — Definitely do not support the revised</td><td>The standard, as currently drafted, is unacceptable. Without the ability to curtail firm transfers to prepare for a next contingency, a “super-firm” priority of transmission service is created for non-native load customers. This goes contrary to the intent of the Open Access Transmission Tariff (OATT) that curtailments be comparable and non-discriminatory. – From</td></tr>
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Organization	Question 15:	Question 15 Comments:
	standard	the OATT: – Curtailment of Firm Transmission Service: In the event that a Curtailment on the Transmission Provider's Transmission System, or a portion thereof, is required to maintain reliable operation of such system, Curtailments will be made on a non-discriminatory basis to the transaction(s) that effectively relieve the constraint. If multiple transactions require Curtailment, to the extent practicable and consistent with Good Utility Practice, the Transmission Provider will curtail service to Network Customers and Transmission Customers taking Firm Point-To-Point Transmission Service on a basis comparable to the curtailment of service to the Transmission Provider's Native Load Customers. All Curtailments will be made on a non-discriminatory basis, however, Non-Firm Point-To-Point Transmission Service shall be subordinate to Firm Transmission Service. When the Transmission Provider determines that an electrical emergency exists on its Transmission System and implements emergency procedures to Curtail Firm Transmission Service, the Transmission Customer shall make the required reductions upon request of the Transmission Provider. However, the Transmission Provider reserves the right to Curtail, in whole or in part, any Firm Transmission Service provided under the Tariff when, in the Transmission Provider's sole discretion, an emergency or other unforeseen condition impairs or degrades the reliability of its Transmission System. The Transmission Provider will notify all affected Transmission Customers in a timely manner of any scheduled Curtailments. The SDT has drafted language contrary to FERC specific requirements on comparability. The FERC has consistently directed Transmission Providers to treat all firm transaction on a comparable basis, yet the SDT, in its latest draft is creating a "super-firm" category for only firm transmission service. By creating a higher priority ("super-firm", non-comparable service) for non-native load customers than for native load, native load customers bear a higher cost burden. This and the costs to the ratepayers for negligible increase in already high reliability due to the performance requirements of the standard makes this draft completely unacceptable for FPL to support. FPL will vote against acceptance of this draft standard unless significant changes are made to comport what FPL believes was the intent of FERC Order 693 with regard to the TPL standards.
Response: The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – <u>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 be considered.</u>		
Exelon Transmission Planning	C — Definitely do not support the revised standard	We appreciate the effort involved in improving this planning standard, and believe in this goal. We are not yet able to support this revised at this time due to the concerns expressed above.

Organization	Question 15:	Question 15 Comments:
Response: Thank you for your comments.		
CenterPoint Energy and CPS Energy	C — Definitely do not support the revised standard	Without re-iterating previous comments, we will summarize that we find this proposed standard to be an overly prescriptive and unrealistic paper chase that does not add value to the planning process. We also are concerned that this standard demonstrates an unhealthy, one sided approach to planning that does not balance reliability goals against other public policy goals, such as cost and landowner impact.
Austin Energy	C — Definitely do not support the revised standard	The proposed standard is overly burdensome and too prescriptive. It will only result in a marginal improvement in reliability and its primary effect will be to devolve into a paper-chase for auditors.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus.		
SRP	B — Unsure about supporting the revised standard	SRP is concerned about what actions will be allowed to meet the higher performance requirements in the transition period and how long will these transition periods last for the different Requirements?
Response: The SDT has developed the Implementation Plan which is included in the 3rd draft of the standard.		
MidAmerican Energy Company	C — Definitely do not support the revised standard	MEC commends the SDT for significantly improving the standard, MEC believes that the standard still must be improved significantly. Probably the most important improvement would be to completely reformat the standard to provide for more organization and clearer VSLs. MEC recognizes that this may result in some initial confusion during the standard writing process, but if such organization results in less confusion over the next decade of applying the standard, the reorganization is well worth it. If the SDT does nothing else, it should reorganize the standard. Here are some suggestions for improvement: R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-

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		distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. MEC recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. MEC believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. R3.3.2.2 - clarify that the single contingency events are the events in the tab le. R3.4 and R5.4.4 - MEC urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." MEC believes that the R5.5.1 should be expanded. Year One definition - MEC suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There is no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, lets assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why??? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner

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		would need to delay completing the study until July 2009. Why??? What is the reliability benefits for delay??? MidAmerican suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? R2.1 - We suggest that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.7.1 - We agree with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? Table 1? Planning Events ? Header: We suggest that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? Extreme Event Evaluation Requirements? 3 Extreme Event Descriptions? 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way."?

Organization	Question 15:	Question 15 Comments:
		Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 2 Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Other numbering and format changes suggested for Table 1 should also be considered for Table 2.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. 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. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. 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. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

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.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1 ~~– Steady State Performance.~~ based on the lists created in Requirement R3.4.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential and Non-Consequential Load Loss have been modified.

Consequential Load Loss: ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's~~

Organization	Question 15:	Question 15 Comments:
~~response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. I. The SDT has changed the definition for Year One to accommodate industry concerns. **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 ~~completion of the previous annual Planning Assessment~~ current calendar year. In response to industry comments, the SDT has removed Requirements R9-R14. R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems". Installation or modification of Protection Systems or Special Protection Systems R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and its efforts to provide and maintain a reliable BES. R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft. **Header note 'e' -** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1. Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To end, Tables 1 and 2 have been combined into one table with		

Organization	Question 15:	Question 15 Comments:
a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts. Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. Extreme Events - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1. **Extreme Event 2b -** Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation.		
SERC Dynamics Review Subcommittee	B — Unsure about supporting the revised standard	SERC is in category BA ? Generally support the revised standard ? B ? Unsure about supporting the revised standard ? See three specific concerns below C ? Definitely do not support the revised standard ? 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This is conflicting with implementation of the TPL standards because modeling details are a gating item to completing some system studies. 2) The proposed sensitivities create significant amount of additional work making the compliance aspect more burdensome and less clear. 3) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause many SERC members to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system.
Response: 1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of Loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Any comments received from the industry on MOD standards will be forwarded to NERC for inclusion into NERC Reliability Standards Development Projects 2010-04, Modeling Data and 2010-05, Demand Data. Requirement R2.4.1 has been modified		

Organization	Question 15:	Question 15 Comments:
to clarify expectations regarding load modeling for dynamics studies. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. **R2.4.1** System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable. 2. The intent of the SDT in requiring performance of sensitivity studies is to identify critical System conditions and to expand planners' portfolio of knowledge about vulnerabilities on their System. This is also an expectation from FERC Order 693 paragraphs 1704 - 1706. Requirement R2.1.3 has been reworded to account for sensitivity studies already performed by the planner. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: 3. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification. **Footnote #10** – 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 be considered.		
MRO NERC Standards Review Subcommittee	C — Definitely do not support the revised standard	While the MRO commends the SDT for significantly improving the standard, the MRO believes that the standard still must be improved significantly. Here are some suggestions for improvement: a. R1.1 is not clear. What does this mean? Surely the SDT does not expect that any time the data is modified a rationale is required. Shouldn't this data be updated as necessary? Wouldn't a requirement for providing a rationale each time such changes are made potentially discourage improvements to the models? This requirement should be clarified and limited to a few specific cases that were there are real reliability concerns. b. R2.5.2 - the SDT should revise the material transmission system changes. Addition of a new substation in one of the transmission lines connected to the plant should be revised to specifically refer to a switching station or to a non-distribution substation. A substation directly serving load is not a good example of a material transmission system change in the context of Generation Unit Stability studies. c. R2.6.2 - The SDT should revise the material transmission system changes because as presently defined, studies will

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		need to be conducted every year for every year in the assessment period. This is because apparently the SDT has defined any system change as a material change. Since it is rare for there to be a system that does not exhibit some system change from year to year, this will mean ten-year and more studies every year. The MRO recommends that the SDT revise this requirement to make clear that only significant system changes are material changes. d. R2.7.1 - The SDT has written this requirement to include a requirement that the responsible entity must indicate how long Operating Procedures apply. This implies that Operating Procedures should be interim measures. The MRO believes that reliability can be maintained with permanent Operating Procedures and recommends that the need to indicate "how long the Operating Procedures will be needed" be deleted from this requirement. e. R3.3.2.1 - The SDT should delete the need to provide the expected duration of the Consequential Load Loss in this requirement because this requirements a probabilistic calculation and probabilistic planning is not the state-of-the art of the industry. This is reflected in the standard which has been written to continue deterministic planning criteria. As a result, it is a contradiction to require this probabilistic quantity in the middle of this deterministic planning standard. f. R3.3.2.2 - clarify that the single contingency events are the events in the table. g. R3.4 and R5.4.4 - the MRO urges that the SDT delete or revise the words "why the remaining Contingencies would produce less severe System results." Given the expansive nature of the Extreme events it is virtually impossible to comply with this requirement. It is more likely that the responsible entity could show that the more likely and more severe Extreme events were studied. It would be better yet if the SDT would merely require that the responsible entity provide the rationale for the selection of Extreme Events that were studied. h. R5.5.1 provides an exclusion for changes in individual generating units that require study. Yet R2.6.2 has a broader definition of when Generating Plant Stability is required. These definitions need to be consistent. The definition in R5.5.1 seems to narrow to be a good definition for "material changes." The MRO believes that the R5.5.1 should be expanded. i. Year One definition - The MRO suggests that the Standards Drafting Team's (SDT's) Year One definition unnecessarily constrains the time between the completion of assessments as compared to the study period to begin no more or no less than 12 to 18 months. There are no reliability benefits derived by constraining the period between the completion of an assessment and the study period for the next study period. In fact, this may encourage a Transmission Planner to unnecessarily delay "completing" a study just to ensure that the 12 to 18 month requirement is met. For example, let's assume that a Transmission Planner's 2008 Assessment is complete as of May 2008. By the definition of Year One, then the study period for the 2009 Assessment will need to begin from May 2009 through November 2009. This means that the 2009 Assessment must include the 2009-2010 Winter Peak and cannot start with the 2010 Calendar Year. Why? If a Transmission Planner wants to have a study period that begins with the calendar year, then the Transmission Planner would need to delay completing the study until July 2009. Why? What are the reliability benefits for delay? The MRO suggests that the definition of Year One be changed to allow the study period to begin no later than 24 months after the completion of the previous year's study.? Definitions: The MRO agrees with the removal of the "Base Case" definition and

Organization	Question 15:	Question 15 Comments:
		the revisions to the other definitions, except as noted below or elsewhere.? Long Term Planning Horizon definition: The MRO suggests a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .".? Accountability: The MRO suggests that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be responsible for R10.? Requirements: The MRO agrees with the revisions to the Requirements, except as noted below or elsewhere.? R1.1 - The MRO agrees with the requirement, but would like more description of what to provide in the technical rationale.? R2.1 - The MRO suggests that this requirement involves too much study work and we ask that the SDT reduce the number of current studies needed for all subrequirements. ? R2.6.2 - The MRO agrees with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .".? R2.7 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R2.7.1 - The MRO agrees with the requirement, but suggest a slight text change replace "? or Special Protection Schemes,?" with " . . . or Special Protection Systems, . . ."? R2.7.1.1 - The MRO disagrees with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability.? R2.7.2 - The MRO agrees with the requirement, as long as it is really required by FERC Order 693 paragraph 1704.? R3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". ? R3.3.2.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning Assessment".? R3.3.2.2 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R5.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES".? R5.2 - This clarifying requirement should also be included in the steady state and short circuit analysis sections.? R5.3 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES."?

Organization	Question 15:	Question 15 Comments:
		R5.4.3.1 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.".? R6 - The MRO agrees with the requirement, but suggest a slight text change of: ". . . shall provide the rationale for and document . . .".? R8 - The MRO disagrees with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process."? Table 1? Planning Events ? Header: The MRO suggests that the header be repeated on every applicable page to be more reader-friendly.? Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer.? Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage.? P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) - This requirement is raising the bar above the existing standards. In the existing standards, this is a Category C event in which load shedding was allowed. A higher criteria for >300 kV may not be appropriate at this time. The new requirement may require the installation of facilities that are costly and have a very long implementation timeframe. We should consider what the cost of this higher requirement might be for ATC and other utilities. If the new >300 kV requirement is not reduced, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years).? P6 - Why isn't the generator listed as a one of the possible subsequent element outages?? P7 - The MRO disagrees with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be an exclusion in this standard similar to the TLP-503-MRO-1 standard (e.g. could be slightly more than 1 mile due to review?.? Extreme Event Evaluation Requirements? 2 - The MRO agrees with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection".?

Organization	Question 15:	Question 15 Comments:
		3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."? Extreme Event Descriptions? 2a - The MRO agrees with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.."? 2b & 3b - The MRO agrees with the descriptions, but suggest referring to the defined term: "Right-of-Way."? 2e, 3.a.i, & 3.a.ii - The MRO agrees with the descriptions, but how large is "large" and how major is "major"?? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? ? 3c - The MRO agrees with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" ? Note 4 - The MRO agrees with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS".? Table 2? 1 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings."? 3 - The MRO disagrees with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur."? Between 3 & 4 - The MRO disagrees with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown."? Planning Events? Same comments on Header, Superscripts, and Shunt Device as in Table 1.? Same comments about stricter requirements for P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV), P6 (>300 kV) as in Table 1.? Same comment about P7 as in Table 1.? Extreme Event Evaluation Requirements? Same comment about Requirement 2 and 3 as in Table 1.? 3 - The MRO agrees with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions."?

Organization	Question 15:	Question 15 Comments:
		Notes5 - The MRO disagrees with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: A. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

B Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to Requirement R2.6.2 (now R2.5.2). 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. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:

C The SDT does not agree that studies are required for every year of the Assessment period. However, please note that Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. 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. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of topology changes constitutes a change sufficient to warrant re-evaluation.

D The SDT has retained this requirement and believes that this information should be included in the Planning Assessment.

E To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

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.

F The SDT has deleted Requirement R3.3.2 and has replaced it with additional language in Requirement R3.1 while adding Header note 'e' and deleting the reference to single Contingencies which will hopefully clarify things.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~— Steady State Performance.~~ based on the lists created in Requirement R3.4.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

G. The SDT disagrees with your comment. The SDT believes that this language is needed to ensure that the worst possible situation is studied based on engineering judgment and knowledge of the System.

H. To address industry comments such as yours, Generating Unit Stability is no longer explicitly addressed in the standard and the definitions of Consequential

Organization	Question 15:	Question 15 Comments:

and Non-Consequential Load Loss have been modified.

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

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

I. The SDT has changed the definition for Year One to accommodate industry concerns.

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 ~~completion of the previous annual Planning Assessment~~ current calendar year.

Accountability - In response to industry comments, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R1.1 – The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 – The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705).

R2.6.2 – Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7.1 (now R2.6.1) – The SDT agrees and had replaced "schemes" with "systems".

Installation or modification of Protection Systems or Special Protection Systems

R2.7.1.1 (now 2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entities' planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – The old Requirement R2.7.2 has been deleted.

Organization	Question 15:	Question 15 Comments:
R3.2.2 – The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES. R3.3.2.1 - To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8. R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft. **Header note 'e' -** For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. R5.1 & R5.2 (now R4.1 and R4.2) – Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording. R5.3 (now R4.3) – The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact. R5.4.3.1 - The SDT has deleted Requirement R5.4.3.1. R6 – The SDT believes "define and document" as written are more appropriate than "rationale for and document". The SDT did not revise Requirement R6 (now R5) as proposed – but did make other modifications to this requirement based on other stakeholder comments.. R8 – The SDT has clarified this in a revised Requirement R7. **R7** Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among ~~neighboring systems~~ adjacent Planning Coordinators 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. Headers - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, Tables 1 and 2 have been combined into one table with a revised format. The headings are repeated on subsequent pages. Superscripts – As part of the change to a single table, the SDT has attempted to clean up various items such as superscripts. Shunt device - The SDT believes that shunt devices are commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. P2.2 – The majority of the SDT believed the 300 kV and higher Systems (EHV) generally represent the backbone of many Systems in the various Interconnections and that the more stringent requirements were appropriate when considering N-1-1 Contingencies of two EHV Facilities. Systems operated above 300 kV generally do not directly serve end-use Load customers but rather act as the medium for moving large amounts of power from production to various Load centers where the energy is then delivered by other Transmission or sub-Transmission Systems to end use customers. It is the desire of NERC		

Organization	Question 15:	Question 15 Comments:

and various stakeholders that the backbone of the electric power grid be robust and held to a higher degree of reliability. The Implementation Plan will address any need for transition and will be included in the next revision.

P6 – This is already covered in P3.

P7 – The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process.

Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that these "System Control" issues should be addressed by the NERC SPCTF drafting team.

Extreme Events 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events.

Extreme Events 2a – The SDT believes that the Extreme Events #2.a. is already sufficient.

Extreme Events 2b & 3b - The SDT agrees with your comments and has made the change. The SDT has removed item 3.b. from Extreme Events since this was already covered in Extreme Event 1.

Extreme Event 2b - Loss of all Transmission lines on a common ~~r~~Right-of-~~w~~Way.

Extreme Event 2e – The SDT suggests that the terms "large", "major", and "successful" be defined between the TP and PC.

Extreme Event 3a – A successful cyber attack would be any attack where an unauthorized person gained access to the systems described in the event.

Extreme Event 3c – The SDT believes that the wording of 3b (was 3c) is already sufficient.

Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation.

Tables 2 – As part of the 3rd draft of the revised standard, the 2 tables have been merged into a single table and a general clean-up of the text has been made.

Table 2, note 1 – The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating.

Table 2, note 3 – The SDT agrees with your comment on making general note 3, located at the beginning of Table 1, "Voltage instability, cascading outages, and uncontrolled islanding shall not occur" applicable to both Steady State and Stability and has made that change in the next version.

Note 4 – The SDT also agrees that the general note 4, at the beginning of Table 1, applicable to both Steady State and Stability and has made that change in the next version.

Organization	Question 15:	Question 15 Comments:
Note 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements under Extreme Events. Note 5 – The SDT also feels that the synchronism requirement should apply to more than just the P1 Category but under certain conditions. As stated in Note 1.a.ii, for planning events other than P1, no generating unit or units totaling more than the Contingency reserve of the Balancing Authority shall be allowed to pull out of synchronism. If less than the Contingency reserve, then the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities		
Modesto Irrigation District	B — Unsure about supporting the revised standard	Concerns about the following: attempt to introduce interconnection stability studies into TPL studies, and redefinition of Consequential and Non-Consequential Load Loss.
Response: The SDT believes that there is no significant distinction between generator and System Stability and has modified the definitions and Requirements R2, R2.6.1 (now R2.5.1), R2.6.2 (now R2.5.2), R5 (now R4), and R5.5 (now R4.4) in the third draft. **R2** Each Transmission Planner and Planning Coordinator shall ~~conduct and document the results of~~ prepare ~~its~~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 ~~including both System and Generating Unit Stability~~. **R2.5.1** For steady state, short circuit, or ~~System~~ Stability analysis: the study shall be five calendar years old or less. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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: **R4.** For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~ **R4.4** ~~At a minimum, t~~Those Planning Event Contingencies in Table ~~2~~1 – ~~Stability Performance~~ that ~~would~~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 created~~,~~. ~~and t~~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. In response to numerous concerns, the following changes were made to the draft standard regarding Consequential and Non-Consequential Load Loss		

Organization	Question 15:	Question 15 Comments:
definitions. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed, Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction. ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~.		
Arkansas Electric Coop. Corp.	B — Unsure about supporting the revised standard	I have a growing concern that the NERC Reliability Standards are not going far enough to ensure adequate and reliable service to customers and users of the BES. Each revision of the standards seem to be driven by the need to preserve the integrity of the grid and preventing cascading blackouts but stop short of ensuring that load continues to be served under contingency conditions and adequate grid capacity is available. For the customers and end users of the system if their load is allowed to be dropped or can not be served because of the lack of capacity then the BES is not reliable. The definitions of Consequential Load Loss and Non-Consequential Load Loss concern me the most. How these definitions are then applied in the tables is also a great concern. Hopefully my previous comments to the other questions in the comment form provide explanation. Another concern I have is the fact that I tried to provide comments last fall to draft 1 of the standards and they were not allowed. After following the instructions provided I provided my comments before the deadline. I later discovered they were not posted. After repeated attempts asking NERC to determine why my comments were not received and posted and showing evidence that they had been provided by the deadline, the only response I received was pretty much "sorry Charlie". Mistakes happen. NERC should be big enough to admit when they make a mistake instead of just blowing them off. I have no way of knowing if or how many times this may have happened before. I am not trying to say that anything malicious was intended, however it does leaves me with concern that fair treatment is being given to all comments and cast a shadow over confidence in the standards approval process.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT believes that your concerns are mostly addressed by the revised Table 1 - Steady State and Stability Performance, along with the revised definitions of Non-Consequential Load Loss and Consequential Load Loss in the updated draft of TPL-001 standard. **Consequential Load Loss:** ~~Load that is no longer connected to a source as a result of the event being studied or which is lost as a result of the load's response to the transient conditions of the event (other than through the action of UVLS or UFLS schemes). Although Load which is lost as a result of the Load's response to the transient conditions of the event is considered Consequential Load Loss and is permitted when Consequential Load Loss is allowed,~~		

Organization	Question 15:	Question 15 Comments:
~~Transmission planning entities are not allowed to rely upon the expectation of such Load loss to meet steady state performance requirements.~~ 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. **Non-Consequential Load Loss:** Non-Interruptible Load loss other than Consequential Load Loss, Supplemental Load Loss, and Load Reduction.~~.~~ ~~For example, non-Interruptible Load loss that occurs through manual (operator initiated) or automatic operations such as under-voltage Load shedding, under-frequency Load shedding, or Special Protection Systems would be considered Non-Consequential Load Loss~~. Comments from AECI were included in the responses to the comments from the first posting. Please go back and review the posted comment form.		
Midwest ISO	C — Definitely do not support the revised standard	We appreciate the hard work of the SDT and understand the difficulty of this task. We applaud the efforts to improve the standard. However, in its present state, in general the revised standard fails in one if its primary stated goals: create a "clear and concise standard". While some of the ideas are an improvement, overall the standard is very meandering and it makes it difficult to figure out what the requirements are for a particular analysis type without flipping back and forth between the scattered requirements. For example R2 addresses various aspects of both Near and long term studies, steady state, short circuit, stability, on peak, off peak and other topics. Then there are separate sections (R3, 4, 5) that speak to the various analysis types again. It probably makes sense to the SDT that has evolved with the drafts and discussions, but when you pick it up it is very confusing. One thing that would help greatly would be to label the major Requirements sections to convey the organization of the document. If the SDT made a topical outline of the standard by major Requirement this could help the team organize the standard better. Resulting topical headers may look something like the following for example, R1: ModelingR2: Study Types and Assessment RequirementsR3: Steady State Analysis MethodsR4: Short Circuit Analysis Methods?R5: Stability Analysis Methods Etc. If it has not been done (and it looks like it has not), the SDT should consider having the language reviewed by the NERC or other legal team. Language that seems clear to experienced engineers may not be precise as is critical for standards that carry monetary penalties. An independent review by a non-engineer lawyer would help greatly. Of course, the SDT would then have to undo some damage that would undoubtedly be done to context by the lawyers - but the pass through legal would be a good step.? ? Other concerns:? P5 requires testing for a single component failure within a Protection System. What is this referencing? How can a PC/TP be expected to be intricately aware of protection systems and effects of single component failures? Under 2.7.2, there is a generic requirement to expand a list of possible corrective actions under 2.7.1 for any sensitivities under R2.1.3, 2.1.4, 2.4.3 and 2.4.4. This is very open ended and subject to interpretation. How can an auditor review such requirements with consistency?
Response: The SDT has attempted to make the latest draft more clear and concise - such as condensing Table 1 and 2 into a single table. The SDT has considered having headers/labels in the document and these are strongly discouraged by NERC's legal staff. The overall format of the tables has been modified to make it more reader friendly. NERC is following the officially sanctioned standards development process with regard to this project just as it follows the process for all standards development		

Organization	Question 15:	Question 15 Comments:
		work. This is an open, transparent process which has been approved by FERC. Review and comment by any entity's legal staff is welcome, but not a required part of the process. The description of the P5 event has been clarified in draft 3 to address your concern. Requirement R2.7.2 has been removed. The SDT has modified Requirement R2.7 (now R2.6) to clarify that Correction 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. **R2.6** For Planning Events shown in Table 1~~ – Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Tables~~s~~ 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 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:
Tri-State Generation and Transmission Association, Inc.	A — Generally support the revised standard	We appreciate the efforts of the SDT, considering the difficulty of the task that was and is before them. Our biggest concern is potential confusion regarding sensitivity studies. Secondly, we absolutely must make the Performance Table completely clear and concise. Additional work now will pay big dividends later. Thirdly, there is some ambiguity of several terms used in the Standard that prevents exact interpretation of significant portions of the Standard. Here are a few additional comments we hope the SDT will find helpful: It may simplify considerations of assessments and modeling work to define ?assessment? as including written documentation. Then the Standard would not need to separately include "and shall include written documentation" in the body of the standard titles. Also, the SDT should make it clear that "assessment" is what is required; that annual re-study analysis may not necessarily be required. Thanks to the SDT for keeping this feature. It will greatly simplify our work, and should speed the audit process as well. There seems to be some ambiguity between either 1) requiring specific years to be studied and 2) leaving timeframe selection to the TP. Assessment for year One or Two (R2.1.1) may be performed by either the TOP or the TP. Studies of year One or year Two are generally considered to be operating studies and should probably not be required in TPL-001-1. Also in R2.1.1, year Five is specified as a required study year. No matter what the requirement says, the TP will need to assess performance for critical timeframes. This would lead to additional study if year four were the critical year for example. And for sensitivity studies of delayed facilities (R2.1.3.3) additional study years might be required. Perhaps a reasonable compromise would be to require something in the 2 to 5-year timeframe, and something in the 6 to 10-year timeframe. For coordination with regional study groups in our area, one would logically choose year 5 and year 10, but the specific choice should be up to the TP (and PC if any). Sole-Customers on radial service who are responsible for facility upgrades should be allowed to elect a lower reliability

Organization	Question 15:	Question 15 Comments:
		than the rest of the system. It seems that operating scenarios required to be studied by TOP should not need study in the planning horizon by the TP, and should be excluded from this standard. Specific comments concerning other sections of the draft standard: 1. In the definition of Generating Stability Study, we suggest "the lack of damping" be changed to "damping" 2. In R2.1 title, please move listed requirements in the second sentence to sub-requirements (they are already there). 3. In R2.1 title sentence, the term "annual current" presents two additional requirements. We suggest those words be deleted. 4. In R2.1, delete the end of the title sentence, ending the sentence with "the following studies" 5. In R2.1.3.2, the meaning of "transfer" is not clear. 6. In R2.1.3.4, the term "variability" is not clear. do you mean "Operating Capability"? 7. In R2.1, R2.2 and 2.4, the phrase "Near Term (or Long Term) Transmission Planning Horizon portion of the" could be omitted. "Near Term" and "Long Term" study horizons should just be specified as sub-requirements of Steady State, Stability, and Short Circuit 8. In R2.7.3, the term "identified System Facilities" is not clear. System Additions? 9. Heading R3.3 is not needed. Renumber section sub headings to 3.2.3, etc.

Response: In response to industry comments regarding sensitivity studies, the SDT has made changes to Requirements R2.1.3 and R2.4.3 and each of their sub-requirements to clarify expectations related to sensitivity studies.

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

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

The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

The SDT crafted the definition of Planning Assessment using the term "documented" instead of "written" such that an assessment can be either in written or

Organization	Question 15:	Question 15 Comments:
electronic format. Requirement R2 states that the assessment is to be performed annually. The SDT chose the Year One definition such that this would be out of the operational planning horizon and into the planning horizon. The SDT chose the years to be studied such that both the Near-Term and Long-Term Planning Horizons would be adequately studied and has not seen a sufficient number of comments to warrant changing the requirements. . Sole-customers who are responsible for facility upgrades are allowed to elect lower reliability than the rest of the system if those customers have signed an Interruptible Load contract arrangement. The SDT believes that all significant probable Contingencies over a wide range of operating conditions should be studied. 1. The definitions for both Generating Unit Stability Study and System Stability Study have both been removed and these Stability areas have been combined into just one Stability area. 2, 3, and 4. The SDT disagrees with the proposed changes and believes that compliance with Requirement R2.1 can be shown through the use of both current and past studies. 5. The SDT believes that "transfers" is generally understood to mean electric power that is transferred or moved from one area to another, and as such, has not added a definition of transfers. 6. The SDT has revised the language to replace "variability" with reactive resources "capability". ~~Variability and outages of r~~Reactive resource~~s~~ capability. 7. The SDT believes that the format and the language of these requirements are appropriate and no additional changes are needed. 8.,The SDT received only a single comment regarding use of the terms "identified System Facilities" and therefore believes the proposed language is clear and appropriate. "Identified System Facilities" are those new or modified facilities which were identified in previous Corrective Action Plans. 9. Requirement R3.3 has been removed and replaced with additional language in Requirement R3.1. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ — Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Lakeland Electric	B — Unsure about supporting the revised standard	Curtailing firm transmission should explicitly be a viable option when preparing for the next contingency if the previous contingency and a credible next contingency call for curtailing firm transactions for reliabilities sake. Not allowing for firm transmission curtailment in this case seems to be a market requirement driving a reliability requirement. Determining the duration of consequential load loss (R3.3.2.1) is impractical as the root cause of the event vice the defined event type (e.g. - loss of line) determines the duration of the outage. A line can be outaged by a temporary lock out of protection device or 15 spans of a line might be destroyed by fire. The difference between the two make determination of duration impractical.

Organization	Question 15:	Question 15 Comments:
		System peak Load (R2.1.1) needs to specify if it is the specific year, season or historical peak demand. Forecasting methodologies affect the system peak load that is projected. Differences between a 50/50 and 80/20 case will result in different forecast peak data.
Response: Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. **Footnote #10** – 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 be considered. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **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. The SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which Load forecasting methodology to use. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.		
Southern Company Transmission	C — Definitely do not support the revised standard	Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. If this is the interpretation, this will cause Southern Company to not support the revised standard. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. In addition, the standard should clarify the accommodation of Conditional Firm Service as defined by FERC Order 890.
Response: The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is		

Organization	Question 15:	Question 15 Comments:
necessary. Footnote 10 in draft 3 of the Standard provides clarification. **Footnote #10** – 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 be considered.		
Brazos Electric Power Cooperative, Inc.	C — Definitely do not support the revised standard	Our biggest concern is the apparent lack of experience or understanding in the repercussions of including so many required studies and detailed documentation. And to what end? The amount of data that would be required to be saved will be so voluminous no one could go through it all to make any meaningful determination in a timely fashion. It's one thing to study every possible combination of outage but you then have to do something with the results, not just record them somewhere because a standard requires it. On the other hand some progress is being made in removing some of the more ambiguous or useless items so we are getting there to some degree. Deleting 1.1.2, 1.1.3, 2.7.3, 2.7.4, and 5.4 are good starts. However it appears some things were added that are just confusing or are unnecessary. 5.5.2 seems to simply restate the obvious intent of the section, to meet the performance requirements so its not really needed. Phrases such as "document why categories were NOT selected" are intuitively obvious. Categories were not selected because, in the judgment of the TP or PC, they were not deemed useful to study so why document this each time. R6 is also a confusing addition to this Standard and we aren't sure what it's intended to require. Use of the word "proxies" is probably not the best substitute for what was intended. We suggest R6 be deleted as well.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). Neither FERC, nor the SDT, believes that every possible combination outage needs to be analyzed for every System condition, but FERC expects those that produce the most severe reliability impacts should be documented (paragraph 1706). In response to industry comments, Requirement R5.5 has been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. The SDT agrees and has deleted the phrase from Requirements R2.1.3 and R2.4.3. **R2.1.3** For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical~~		

Organization	Question 15:	Question 15 Comments:
~~rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~sensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: The industry did not seem to find usage of "proxies" in Requirement R6 (now R5) unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to the use of proxies.		
LCRA TSC	A — Generally support the revised standard	LCRA had a comment on the first posting stating that the loss of any two Transmission circuits on a common structure should be viewed as a single contingency as a single component failure (tower, shield wire, conductor, hardware) could in-fact lead to the loss of two circuits. In the second draft, this outage is still being viewed as a Multiple Contingency (P7). At the same time, the loss of a tower line with three or more circuits is being viewed as an Extreme Event, when the same single failure could lead to the loss of multiple circuits. So, even if a double circuit outage is viewed as a Multiple Contingency, shouldn't a multiple circuit outage be viewed the same. In the Definitions of Terms Used in Standard, Extreme Event is defined as Events which are more severe and have a lower probability of occurrence than Planning Events. What is a "lower probability of occurrence"? Is this to be determined by each TP or TO? How is this probability determined? Are we to assume from this definition that we can use probabilistic planning to determine which Events should be studies even at the N-1 level?
Response: The SDT does not believe that the loss of a tower line with three or more circuits is similar in probability to two circuits on a common structure. Therefore, it is appropriate to classify the events differently. The SDT views "lower probability of occurrence" events as those events that occur much less often than Planning Events. The SDT does not intend for this probability to be determined by each utility. The SDT desires that Extreme Events be studied - but do not necessarily have to have Corrective Action Plans.		
NERC and Regional Coordination	C — Definitely do not support the revised standard	Changes should be made to the sensitivity analysis. See question 10 above. R2.6 - The need to restudy previously studied years should be left to the transmission planner when in their judgment there is a material change. Based on the material change the TP should be responsible for determining what aspects of the performance requirements need to be proven
Response: Please see the response to question 10. The SDT believes that past studies must be five calendar years old or less to be relevant and the associated models should not have had material changes. Requirement R2.5 and its sub-requirements have been removed from the proposed standard. Guidelines for the use of past studies to support the Planning Assessment have been added to what is now Requirement R2.5.2. 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. It is up to the Transmission Planner and Planning Coordinator to provide specificity as to what type of		

Organization	Question 15:	Question 15 Comments:
topology changes constitutes changes sufficient to warrant re-evaluation. **R2.5.2** For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:		
IESO	A — Generally support the revised standard	(i) We generally support the direction and principle of the revised standard. It is a step in the right direction to more clearly stipulate the types of events and expected performance requirements with inclusion of multiple element contingencies and multiple single contingencies, and allowance for interruptions to firm transmission services and non-consequential load loss. (ii) More details and refinements are expected to be provided that address the issue of sensitivity testing, reduce the number of layers in the subrequirements (to facilitate ease of developing Measures and Violation Severity Levels), more clearly specify the responsible entities, etc. We look forward to seeing these improvements in the next revision, along with the first draft of Violation Risk Factors, Time Horizons, Measures, Data Retention Periods, and Violation Risk Factors when the requirements approach their near final draft form. (iii) We suggest the SDT review the development plan with the Standard Process Manager, especially the timing for posting the standard for balloting, responding to comments and conducting recalculating ballot. The timing between the initial ballot and recirculation ballot is usually short, and the balloted standard is not supposed to change. The proposed development plan appears to allow a long lead time between the two ballots, and for making changes to the standard between them.
Response: i. Thank you for your comments. ii. The SDT has streamlined the document and the tables to add clarity and has added the elements that were missing from the previous drafts. VRF, tec., have been added to the 3rd draft. iii. All development plans are reviewed with the Process Manager prior to finalization as per established procedure.		
North Carolina Electric Membership Corp	B — Unsure about supporting the revised standard	While we are satisfied that the changes are moving in the right direction, we share concerns that are being expressed by other SERC TPs and PCs that the standard may be overly prescriptive in some areas such as the sensitivities being required.
Response: The SDT agrees and has clarified the language to allow the Transmission Planner and Planning Coordinator to choose the sensitivities (Requirements R2.1.3 & R2.4.3).		

Organization	Question 15:	Question 15 Comments:
R2.1.3 For each of the studies described in Requirements R2.1.1 and ~~Requirement~~ R2.1.2, sensitivity case(s) that are intended to stress the System with ~~sensitivities~~ variations ~~that reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment: **R2.4.3** For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:		
E.ON U.S. Transmission Planning	C — Definitely do not support the revised standard	It is confusing that single Contingency and multiple Contingency are used throughout the document when the Categories in Tables 1 and 2 are Single Contingency and Multiple Contingency. Also System normal, normal conditions and Normal System are spread throughout the document. If they all mean the same, use the same wording. If not, explain the difference. R2.4.1. - Does this apply only to motors directly connected to the BES? Is there a size (hp/MW) limit? Who is responsible to provide this data to the Planning Coordinator? I would think it would both the Distribution Providers or the Generator Owners but R9 & R12 do not mention this. R2.4.1 refers to ?the dynamic behavior of Loads? and induction motor loads. How would this model data be developed, and by who? R2.5.2. - Define “Material”. Is an addition of a load tap point material? R2.6.2. ? Define ?study area?. Does a topology change over 300 miles away trigger a stability study for a generating plant? R2.7.1.1. ? Define ?project initiation date?. Would this include going to the PSC to get approval or just when construction begins? R3.2.1 states ?? and identify how the generators are treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.2.2 states ?? and identify how loadability is treated in the steady state simulation.? What is meant by ?treated?? I request the use of more descriptive wording. R3.3.1 “System normal” is a Planning Event included in Table 1. R3.3.2 capitalize ?Single? if you referring to P1 and P2 events. If not, this is confusing. R3.3.2.1 states ?Consequential Load loss (expected maximum demand and expected duration) following a single Contingency shall be identified in the Planning Assessment.? Quantification of expected duration requires a probability analysis of load cycles, repair time, and potentially of other factors that will be difficult, if not impossible, to develop with any confidence. The Planning Assessment is based on a deterministic evaluation. Requiring the expected duration is

Organization	Question 15:	Question 15 Comments:
		inconsistent and useless. R3.3.2.2 Is this the intent? ? Following Single Contingency events, Transmission configuration changes and redispatch of generation can be simulated to return the system to Normal Rating provided that all Facilities shall be operating within their Emergency Rating. R5.3 states ?? and identify how the generators are treated in the simulation.? What is meant by “treated”? I request the use of more descriptive wording. R5.5.1 and R5.5.2 should be moved to 2.5. These requirements outline the generators and the sensitivities to be analyzed. R5 appears to focus on Tables 1 and 2. R5.5.2 states ?Shall be performed for changes in the real power output?? What types of ?changes?, or ?changes? due to what? Is intention of the requirement, that Generating Unit Stability be assessed at two levels of real power output that differ by more than 10% of the existing capability or more than 20 MW, whichever is greater? R6 states ?? and document the proxies used in the simulation?.? What is meant by ?proxies?? I request the use of more descriptive wording. R8 ends with ?This distribution shall include:? Include what? Table 1 There used to be limits on multiple circuit towers and common ROW greater than 1 mile. Is this left to the Transmission Planner and Planning Coordinator ? Extreme Events ? Item 3b is the same as Item 1, this should be removed. Table 2 Note 5.a.ii How can this be applied when the largest unit in the Balancing Authority Area is larger than the contingency reserve of the Balancing Authority. This requirement is excessive. At some level, subsequent trips of generators and/or lines should be allowed as long as Cascading does not occur.

Response: The row headers are capitalized in the Table. Please note that the two Tables have been changed to just one Table in this draft.

R2.4.1 – The SDT does not believe the requirement applies only to motors directly connected to the BES, nor is there a specific hp/MW limit. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources, ~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 – Requirement R2.4.1 has been modified to clarify expectations regarding load modeling for dynamics studies.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic

Organization	Question 15:	Question 15 Comments:

behavior of the Load is acceptable.

R2.5.2 – Requirement R2.5 and its sub-requirements have been removed from the proposed standard.

R2.6.2 (now R2.5.2) –The SDT believes that it is up to the Planning Coordinator and Transmission Planner to define the study area and to determine which System changes could impact the study area

R2.7.1.1 (now R2.6.2)– The SDT has not defined a project initiation date and will leave that definition to be determined by the Transmission Planner and Planning Coordinator.

R3.2.1 – "Identify how generators are treated" means that you identify at what voltage you would believe that the generator would trip. Any time you run a dynamic simulation or a steady state simulation and you don't trip the generator, you are implicitly assuming that it will ride through the voltage excursion obtained in the simulation. The requirement is to identify what you are assuming for voltage ride-through criteria for the generators you have modeled.

R3.2.2 – The SDT has changed 'treated' to analyzed'. .

R3.3.2 For all generators, studies shall consider the minimum steady state voltage limitations ~~of all generators~~ and identify how the generators are ~~treated~~ analyzed in the steady state simulation.

Requirement R3.3.1 has been removed and replaced with additional language in Requirement R3.1.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

R3.3.2 – This requirement was deleted.

R3.3.2.1 **-** To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8.

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.

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5.3 - The SDT agrees that the word "treated" is vague and has revised Requirement R5.3 (now Requirement R4.3.2) and Requirement R3.2.2 (now R3.3.3) to clarify the requirement.

Organization	Question 15:	Question 15 Comments:
R3.3.3 For all Transmission lines, studies shall consider relay loadability and identify how loadability is ~~treated~~ analyzed in the steady state simulation. **R4.3.2** ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~. R5.5.1 & R5.5.2 - In response to industry comments, both Requirement R2.5 and Requirement R5.5 have been deleted since Generating Unit Stability is no longer explicitly addressed in the standard. R6 (now R5) - Most of the industry did not find usage of "proxies" in Requirement R6 unclear or confusing. Therefore, the SDT has determined that no change to Requirement R6 is needed with regard to proxies. R8 - The incomplete sentence was a typo and has been deleted from Requirement R8. Footnote 12 has been added to Table 1 to address your comment on the exclusion criterion for multiple circuit towers. **Footnote 12** - Excludes circuits that share a common structure for 1 mile or less. The SDT agrees with removing the redundancy found with Extreme Event 3.b. Please see footnote 1.a.ii for clarification. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
ERCOT System Planning	C — Definitely do not support the revised standard	The NERC reliability standard requirements should represent the minimum studies necessary to achieve reliability given the broad range of entities of various sizes and capabilities. Instead, the standards seem to represent the gold standard of the kind of studies that could be accomplished (steady-state, short circuit, and stability) given infinite time and resources with the number and variety of contingencies and sensitivities necessary. This level of steady state and stability studies can only be undertaken by the larger entities with a deep and experienced engineering staff. Why are most of the requirements applicable to a Transmission Planner and Planning Coordinator? Unless they are the same entity, this is an unnecessary duplication of effort. If a Planning Coordinator has a number of Transmission Planners in its region, then these requirements have to be fulfilled by each Transmission Planner for its individual area and the Planning Coordinator for the region made up of the individual areas? What is the Planning Coordinator coordinating if it is duplicating the work of the Transmission Planner?
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. This standard does not represent the gold standard, but rather the SDT is developing a standard based on consensus industry support.		

Organization	Question 15:	Question 15 Comments:
The SDT recognizes that the Transmission Planner and Planning Coordinator must work closely together as defined in the NERC functional model. The Transmission Planner and Planning Coordinator should closely coordinate all work to avoid any unnecessary duplication. Requirement R6 has been included in the standard to ensure that Planning Assessments are complete and coordinated in situations where the Transmission Planner and Planning Coordinator are not the same entity**.**		
American Transmission Company	B — Unsure about supporting the revised standard	We agree with most of the requirements of revised standard. However, the following list of suggestions and comments are given for consideration. Definitions: We agree with the removal of the "Base Case" definition and the revisions to the other definitions, except as noted above or below. Long Term Planning Horizon definition: We suggest a slight text change of: "Transmission planning period that covers years six through ten. Studies beyond ten years are required to accommodate . . .". Accountability: We suggest that Transmission Service Provider be added because we also suggest that the Transmission Service Provider be the responsible entity for R10. Requirements: We agree with the revisions to the Requirements, except as noted above or below. R1.1 - We agree with the requirement, but would like more description of what to provide in the technical rationale. R2.1 - We agree with the requirement, but suggest this text change, ". . . by the following annual studies . . .". R2.6.1 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.6.2 - We agree with the requirement, but suggest a slight text change of: " . . . short circuit, Generating Unit Stability or System Stability analysis . . .". R2.7 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R2.7.1 - We agree with the requirement, but suggest a slight text change of: " . . . or Special Protection Systems, . . ." R2.7.1.1 - We disagree with the "include project initiation date" portion of this requirement. The initiation date is often uncertain and subject to change, which may add considerable work to investigate, monitor and update the date. In addition, we do not know why this information is required to assure BES reliability. R2.7.2 - We agree with the requirement, as long as it is really required by FERC Order 693 paragraph 1704. R3.2.2 - We agree with the requirement, but suggest a slight text change of: "For all BES Transmission lines . . .". R3.3.2.1 - We agree with the requirement, but suggest a slight text change of: ". . . shall be allowed in the Planning

Organization	Question 15:	Question 15 Comments:
		Assessment". R3.3.2.2 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R5 - Is the text referring to "known planned outages" and "known long term outages"? What is the distinction that is meant to be made between the two specified types of outages? R5.1 - We agree with the requirement, but suggest a slight text change of: ". . . the response of the applicable portion of the BES". R5.2 - This clarifying requirement should also be included in the short circuit analysis section. R5.3 - We agree with the requirement, but suggest a slight text change of: ". . . capability of all generators that may have a significant adverse effect on the BES." R5.4.3.1 - We agree with the requirement, but suggest a slight text change of: ". . . within their Facility Ratings and within the time period allowed by the applicable time limited ratings.". R8 - We disagree with the requirement, but suggest a text change of: "Each Planning Coordinator shall establish a list of neighboring system and coordinate the distribution of Planning Assessment results among affected entities the listed neighboring systems, coordinating analysis of these results through an open and transparent peer review process." Table 1Planning Events Header: We suggest that the header be repeated on every applicable page to be more reader-friendly. Superscripts: The superscripts do not refer clearly to the respective notes (e.g. there are number notes in the beginning of the table, in the extreme events evaluation requirements section, in extreme event description section, and at the end of the table). Perhaps the notes at the end of the table should have unique numbering to make the superscript references clearer. Shunt device: To avoid the need for future interpretation or clarification, we suggest that the meaning of shunt device be explained or defined somewhere in the standard (e.g. cap bank, inductor bank, SVC, STATCOM, etc.). We need to find out how shunt device outages can (or could in the future) be automatically included in the ACCC routine. We interpret that if each stage of a capacitor bank has a circuit switcher, then the outage would be of the largest cap bank stage. P2.2 (>300 kV), P2.3(>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) - We recognize that the addition of this requirement is an attempt top raise the bar above the existing standards. However, the more stringent performance criteria should only be adopted if there is sufficient evidence to demonstrate the expected reliability risk (i.e. system impact x probability of occurrence) is high enough to warrant the cost of the system modifications that would be needed to meet the criteria. System modifications that involve the installation of line and substation facilities >300 kV will likely take years and cost tens to hundreds of millions to build. It would be helpful to have a reliability risk analysis that justifies the application of

Organization	Question 15:	Question 15 Comments:
		this performance criteria before it is adopted. If the proposed >300 kV performance requirement is retained, then we would want the implementation timeframe to be long enough to allow reasonable time to transition from a system built to the old requirement to a system built for the new requirement. The time needed for planning, design engineering, regulatory approvals, and construction of >300 kV facilities can be very long (e.g. up to 10 or more years). P7 - We disagree with this requirement. Wisconsin statues require giving preference to using existing ROW for new transmission circuits, but this requirement discourages building multiple circuits on common ROW. Should there be a waiver in this standard similar to the TLP-503-MRO-1 standard for lines slightly more than 1 mile based on a review? Extreme Event Evaluation Requirements2 - We agree with the requirement, but perhaps a definition be added for "System Controls", since one exists for "System Protection". 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Extreme Event Descriptions2a - We agree with the description, but suggest a slight text change of: "Loss of a structure or tower line with three or more circuits.." 2b & 3b - We agree with the descriptions, but suggest referring to the defined term: "Right-of-Way." 2e, 3.a.i, & 3.a.ii - We agree with the description a, but how large is "large" and how major is "major"? 3.a.v - What is meant by successful cyber attack? Is it a type of cyber attack that is documented to have been successful? 3c - We agree with the description, but suggest a slight text change of: "Other events based upon actual operating experience such as:" Note 4 - We agree with the description, but the acronym FACTS should be explained in the standard or a definition be added for "FACTS". Table 21 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "The System shall remain stable. In addition, Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." 3 - We disagree with this note. We suggest that it be expanded to include the applicable part as Table 1. "Dynamic voltage instability, Cascading outages, and uncontrolled islanding shall not occur." Between 3 & 4 - We disagree with omitting Note 4 of Table 1 from Table 2. We suggest including: "Consequential Load and consequential generation loss is allowed for all events shown." Planning Events Same comments on Header, Superscripts, and Shunt Device as in Table 1.Same comments about stricter requirements for P2.2 (>300 kV), P2.3 (>300 kV), P3 (>300 kV), P4 (>300 kV), P5 (>300 kV) as in Table 1.Same comment

Organization	Question 15:	Question 15 Comments:
		about P7 as in Table 1.Extreme Event Evaluation Requirements Same comment about Requirement 2 and 3 as in Table 1. 3 - We agree with the requirement, but suggest a slight text change of: "Simulate Normal Clearing unless otherwise specified in the Extreme Event Descriptions." Notes5 - We disagree with limiting this requirement to just Category P1 category. We suggest that the synchronism requirement be applied to more categories.

Response: The SDT believes that a review of system conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

In response to industry comments, the SDT has removed Requirements R9-R14 thus eliminating any need to add the Transmission Service Provider.

R1.1 - The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data.

R2.1 - The SDT believes that the existing language is appropriate and there needs to be a distinction between current and past studies that would allow both to support compliance with the requirement.

R2.6.1 & R2.6.2 - Based on comments from others, the SDT has removed the requirements for separate Generating Unit Stability analysis and System Stability analysis.

R2.7 (now R2.6) – The SDT believes that it is.

R2.7.1 (now R2.6.1) - The SDT agrees with the proposed change.

Installation or modification of Protection Systems or Special Protection Systems.

R2.7.1.1 (now R2.6.2) - The SDT believes that a project initiation date is an effective measure to track a functional entity's planning and engineering activities and their efforts to provide and maintain a reliable BES.

R2.7.2 – Requirement R2.7.2 has been deleted.

R3.2.2 - The Purpose section of the Standard states that this Standard is to develop requirements for the Bulk Electric System, BES. No change required.

R3.3.2.1 – Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.8 which includes the term 'Planning Assessment'.

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.

Organization	Question 15:	Question 15 Comments:

R3.3.2.2 - Based on your comment, the SDT has addressed the applicable time-limited rating in what was Header note 'a' for Steady State Only in Table 1 - Steady State & Stability Performance. Requirement R3.3.2.2 has been deleted in favor of Header note 'e' in the revised Table. Please note that the two tables in the second draft have been reduced to one table in the third draft.

Header note 'e' - For all Planning Events, planned System adjustments such as Transmission configuration changes and redispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings.

R5 - The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all Planning Assessments. Further, both Requirements R3 and R5 (now R4) have been revised to make reference to Requirement R1.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R4. For the Stability portion of the Planning Assessment, as described in Requirement R2.4~~ and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

R5.1 - Most of the industry did not have difficulty understanding that the analysis is limited to the Transmission Planner's or Planning Coordinator's portion of the BES. Therefore, the SDT is not persuaded by your comment to add extra wording.

R5.2 - The SDT has moved the short circuit analysis from Requirement R4 to Requirement R2.7 and R2 already references BES.

R5.3 - The SDT disagrees with the suggested change due to the additional studies that would be required to determine which generators would have an adverse impact.

The SDT has deleted R5.4.3.1.

The SDT has clarified this issue in Requirement R8 (now R7).

R7 Each Planning Coordinator shall coordinate the distribution of Planning Assessment results among~~ neighboring systems~~ adjacent Planning Coordinators 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.

Organization	Question 15:	Question 15 Comments:
Header - The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format. The Planning Events are shown on one page so repeating the headings will not be needed. Superscripts - All the notes from both tables have been combined and listed numerically. Shunt device - The SDT believes that shunt device is commonly used in the electric utility industry and does not require any further explanation. The SDT recommends contacting the software manufacturer for additional information about the ACCC routine. The SDT believes that the cap bank outage would be based on what elements would need to trip in order to clear the simulated fault condition. P2 - The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in Corrective Action Plans. The Implementation Plan will be addressed in the next posting of the standard. P7 - The SDT is cognizant of the concerns surrounding the construction of new Transmission lines, including the desire by many to fully utilize existing Right-of-Ways. In its consideration of Footnote 12 (exclusion for common structures less than 1 mile), the SDT considered the impact that this requirement could have on construction of new Facilities. However, after deliberations, the SDT believes that the 1 mile exclusion should be maintained for the reliability of the BES and that individual exceptions can be addressed within the NERC process. Extreme Events 2 - The SDT agrees that "Protection System" is defined in the Glossary of Terms Used In Reliability Standards. However, the SDT believes that this issue should be more properly addressed by the NERC SPCTF drafting team. 3 - The SDT has previously included "For all Extreme Events evaluated" at the beginning of the Evaluation Requirements for Extreme Events. No change required. 2a - The SDT believes that the Extreme Events #2.a. is already sufficient. 2b - The SDT will use the defined term of "Right-of-Way" as suggested (see 2b steady state and 2 g Stability). 2e et al - The SDT suggests that the terms "large", "major", and "successful" be defined between the Transmission Planner and Planning Coordinator. 3a - The SDT believes that the wording (was 3c) is already sufficient. No change required. Note 4 - The SDT believes that "FACTS" is commonly used in the electric utility industry and does not require any further explanation. Table 21 - The SDT has reviewed your comment and feels that your request to add "Facility Equipment Ratings shall not be exceeded. Planned System adjustments are allowed, unless precluded in the Requirements, to keep Facilities within the Facility Ratings, if such adjustments are executable within the time duration applicable to the Facility Ratings." apply to Stability is not appropriate. For the purposes of this standard, Facility Equipment Ratings refer to steady state calculated values and planned System adjustments refer to the time frame associated with returning the thermal flow within the applicable steady state Facility Rating. 3 - The SDT agrees with your comment and has made that change in Header note 'a' in the next version. Also, the next version will combine Tables 1 and 2		

Organization	Question 15:	Question 15 Comments:
into one table with a revised format. 3 & 4 - The SDT has reformatted and combined the two Tables into a single Table for the next draft. 3 – The SDT has already included "For all Extreme Events Evaluated" at the beginning of the Evaluation Requirements for Extreme Events. 5 - The SDT also feels that the synchronism requirement should apply to more than just P1 Category but under certain conditions and has adjusted the notes accordingly. **Footnote 1.a.ii -** For all other Planning Events: No generating unit or units totaling more than the Contingency ~~r~~Reserve of the Balancing Authority (or Reserve Sharing Group if applicable) shall be allowed to pull out of synchronism. Generators that pull out of synchronism must have out-of-step protection or some other means to trip the generator for this condition and the resulting apparent impedance swings must not pass through relay characteristics that would result in the tripping of any Transmission System elements other than the generating unit and its direct connection Facilities.		
Duke Energy	B — Unsure about supporting the revised standard	While we generally support the revised standard, we are unsure of the total cost impact, and whether the additional costs are justified by increased reliability. 1) Load Modeling is a significant open issue. The models for dynamic studies have yet to be developed and the data is not in hand. This standard should allow for the use of the best available information. 2) Category P6 is the loss of a system element, following system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service and non-consequential load loss is allowed. The table, however, is not clear whether the interruption of firm service and non-consequential load loss is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. Duke Energy does not believe this would be an acceptable situation for the users, owners and operators of the bulk power system. 3) The statement in R2.7 "Corrective Action Plans do not need to be developed solely to meet the performance requirements for sensitivities," implies that there are performance requirements for sensitivity studies. Recommend rewording to clarify that there are no performance requirements for sensitivity studies. 4) Recommend rewording R3.3.2.1 as follows: "The single highest consequential load loss and its expected duration following a single contingency shall be documented in the Planning Assessment." 5) In R5.3 the statement, ?and identify how the generators are treated in the simulation,? should be deleted. The word "treated" is vague and typically specific equipment modeling is not identified in studies. The implementation schedule should also take into account the Standard to develop and provide this data is not approved. Since this data is not yet available, please revise the statement as follows: ?Studies shall use the best available information to consider the voltage

Organization	Question 15:	Question 15 Comments:
		ride through capability of all generators." 6) In Table 1, Category P2 Event 1 needs to be revised to recognize the impact of this event on Bulk Electric System reliability for events on the system that are > 300 kV vs. events on the system that are <= 300 kV. P2.1 should not allow for interruption of firm transmission service or loss of non-consequential load for > 300kV; however, it should allow for interruption of firm transmission service or loss of non-consequential load for <= 300 kV. The requirement as currently written would require expenditures for the <= 300 KV system where such an event has minimal impact on Bulk Electric System reliability. In addition, the likelihood of events needs to be considered as requirements are developed. A review of Duke Energy Carolinas data shows that the likelihood of a P2.1 event on Duke's 100 kV system is an order of magnitude less than for a P1 event on the same 100 kV system. This is another indicator that the requirement as written would result in the need for expenditures that provide minimal value to enhancing the reliability of the Bulk Electric System.

Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and has taken them into consideration in its deliberations in the development of this draft.

1. The SDT agrees and believes that industry guidance is needed to capture the appropriate dynamic behavior of loads. In response to comments from you and others in the industry, the SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. Requirement R2.4.1 has been modified to clarify expectations regarding Load modeling for dynamics studies.

R1 Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations.

R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.

2. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification.

Footnote #10 – 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 be considered.

3. The SDT has modified the language dealing with the sensitivities in Requirement R2.7 (now R2.6) and added the phrase "run in accordance with Requirements R2.1.3 and R2.4.3." However, the performance requirements for sensitivity studies are the same as the performance requirements for the base study. The difference is that a Corrective Action Plan is required when performance requirements are not met in the base study. A Corrective Action Plan is not

<table>
<tr><th>Organization</th><th>Question 15:</th><th>Question 15 Comments:</th></tr>
<tr><td colspan="3">necessarily required when the performance requirements are not met for a sensitivity study.

R2.6 For Planning Events shown in Table 1~~ – Steady State Performance and Table 2 – Stability Performance~~, when the analysis indicates an inability of the System to meet the performance requirements in ~~the t~~Table~~s~~ 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 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:

4. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft.

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.

5. The SDT has revised Requirement R5.3 (now R4.3.2) to provide clarification in this area.

R4.3.2 ~~Studies shall consider~~ Simulate generator performance under anticipated conditions including how the voltage ride through capability ~~of all generators and identify how the generators are treated~~ is analyzed~~in the simulation~~

6. The SDT feels that for this event (explained in detail in footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping of Non-Consequential firm Load following any single Contingency.</td></tr>
<tr><td>Florida Reliability Coordinating Council, inc</td><td>C — Definitely do not support the revised standard</td><td>The SDT should consider and allow, for all planning events, , loss of Non-Consequential load as an interim measure for a period of up to 5 years in the situation where system load growth has caused post-contingency action plans to not effectively bring Facilities within normal operating limits due to unexpected or unforeseen regulatory requirements, equipment capability* and/or the installation of large industrial/commercial customers. *Equipment Capability is added to address unforeseen industry changes in the methodology used to calculating the rating of equipment.</td></tr>
<tr><td colspan="3">**Response:** Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that 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 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.</td></tr>
<tr><td>Central Maine Power</td><td>B —Unsure about supporting the</td><td>Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard.</td></tr>
</table>

Organization	Question 15:	Question 15 Comments:
Company	revised standard	Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the

Organization	Question 15:	Question 15 Comments:
		purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system. k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertent trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizon unless otherwise defined in the planning horizon. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?
ISO New England Inc.	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, there are several issues of concern that prevent us from supporting the present draft of the revised standard. We offer the following constructive comments in an effort to support the worthwhile effort that is being pursued so that we can reach a point of satisfaction that we could vote to support the revised standard. Our concerns are listed in a rough order of priority. a. This standard as drafted does not allow exceptions for small parts of the system as long as interconnected system reliability is maintained, which is allowed in the existing TPL standards in footnotes b) and c) in Table 1. Unless such exceptions are allowed significant transfer restrictions or large reinforcements must be made. The applicable TPL footnotes

Organization	Question 15:	Question 15 Comments:
		are: Existing TPL footnote b) Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. Existing TPL footnote c) Depending on system design and expected system impacts, the controlled interruption of electric supply to customers (load shedding), the planned removal from service of certain generators, and/or the curtailment of contracted Firm (nonrecallable reserved) electric power Transfers may be necessary to maintain the overall reliability of the interconnected transmission systems. b. This standard does no address base conditions. Without defining base conditions the initial status of generation dispatch and transfers across the system is ill defined. Therefore the contingency analysis doesn't have a predictable basis for a consistent and repeatable study. c. The reference to Special Protection Systems is completely permissive. Although there are good applications for Special Protection Systems, their use must be constrained to have a reliable system and to promote construction of needed infrastructure. d. This standard does not provide flexibility to shed load, which restricts the ability to control post contingency response for low impact events. This may result in advancing need for upgrades in response to low impact events. This may result in advancing need for upgrades in response to low impact events. This is in conflict with FERC's directive to have the Transmission Provider waiting for market response to transmission needs and having the Transmission Provider provide a role to back stop the market. e. Definition of the Long-Term Planning Horizion. The planning horizion, for assessment purposes should be limited to 10 years. Such an assessment should be sufficient to identify requirements that may take an extended time to implement. f. Definition of Planning Coordinator is part of the NERC Functional Model, Remove from the standard. g. Put headings on each section to identify the requirements of the section. h. With respect to R2.2 - Delete "current" from the phrase "current System Peak Load Study" and replace "study" with "assessment." i. Remove R2.2.1, the requirement to extend the assessment beyond 10 years. What does the length of the project have to do with the assessment? If it takes 15 years to build something, why does this require a review of year 15? What is the purpose of this assessment? j. R3.3.2 requires clarification - This standard needs to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is completely unnecessary to test all events. For example, contingencies may be limited to relevant disturbances that are contained within or directly impact the studied system.

Organization	Question 15:	Question 15 Comments:
		k. With respect to R3.2.1 - Clarify whether the intent of the standard is to address station service minimum voltage limitation, maximum leading VAR absorption capability or both at steady state. l. Remove R3.2.2 - Relay loadibility is addressed in the PRC-023 Standard. m. With respect to R3.3.2.1 - Recommend the removal of the requirement to assess the expected duration of Consequential Load loss. It's not considered anywhere else in the standard. n. With respect to R3.3.3 - The paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Rationale for inclusion of testing should not be required; should only need to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies. o. With respect to section R5 - The concept of planned and long-term outages should apply to the general Planning Assessment, or not at all. It should not be specific to the Stability Assessment. p. The provisions of Section R5.3 should have a corresponding MOD standard apply a requirement to provide information regarding all direct and indirect protective and control actions that could result in the inadvertant trip of the generator. Such a provision should include "other equipment (e.g. HVDC, SVC's, Statcoms)", and identify how those devices are treated in the simulation. q. Planned outages should be addressed in the operating horizion unless otherwise defined in the planning horizion. r. Recommend allowing the same non-consequential interruption for >300kV as for <300kV. Distinctions and acceptability should be based on consequence, not voltage class. s. What is a "current" study?

Response: A. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that 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 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.

B. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

C. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

Organization	Question 15:	Question 15 Comments:

D. The SDT has made clarifications regarding Firm Transmission Service and Non-Consequential Load Loss. Footnote # 10 has been added to the end of Table 1. The standard does not preclude the possibility of obtaining contractually interruptible load. It is the general opinion of the SDT that dropping of Non-Consequential Load should not be allowed for the Planning Events involving only one element as described in Table 1 of the proposed Standard, and to meet the intent of FERC Order 693. Further, this Standard is proposed to "raise the bar" to improve System reliability, which would require responses (Corrective Action Plans) to address those so-called low-impact events that may have been overlooked or ignored with the existing Standard TPL-002-0.

Footnote #10 – 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 be considered.

E. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned facilities can be completed. This information needs to be included in the Assessment.

F. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

G. The SDT also feels that the Tables need to be as clear and concise as possible. To that end, the next version will combine Tables 1 and 2 into one table with a revised format.

H. The SDT believes that the existing language is appropriate.

I. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted under some circumstances. For example, if it takes 15 years to build a Transmission line, then the need for that line would have to be determined 15 years ahead of the in-service date. Therefore, Requirement R2.2.1 requires you to perform an Assessment on year 15 if it takes you 15 years to build a line.

J. The SDT has removed Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in **R**equirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results.

R3.1 Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.

K. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 is to determine if generators could continue to operate or if they would trip off following the Contingency.

Organization	Question 15:	Question 15 Comments:

L. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability level, which may add to the existing Contingency and perhaps, result in an unbounded cascading event.

M. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R 2.9 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been deleted in favor of new Requirement R2.9.

R2.9 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.

N. The SDT has re-written Requirement R3.3 (now Requirement R3.5) to address your initial concern. Although the language and format of the proposed Standard have been revised from earlier versions, the SDT continues to believe that the Transmission Planners should evaluate the System performance for the events that are expected to produce the more severe System impacts, including both single and multi-Contingency events. The wording of new Requirement R3.5 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded.

R3.5 Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.

O. The SDT agrees and has moved this concept within Requirement R1 (see Requirement R1.1.1) so that it is applicable to all planning Assessments. Further, both Requirement R3 and Requirement R5 have been revised to make reference to Requirement R1.

R1.1.1 Planned outages of generation and Transmission Facilities, if specifically known.

R3. For the steady state portion of the Planning Assessment, each Transmission Planner and Planning Coordinator shall perform analysis for the Near-Term and Long-Term Transmission Planning Horizon studies in Requirement R2.1 and Requirement R2.2. ~~The studies shall be based on computer power flow simulations that analyze BES normal performance (n-0) and System response to c~~Contingencies ~~in Table 1 – Steady State Performance.~~ The studies shall be based on computer simulations using models utilizing data provided in Requirement R1.

R5 For the Stability portion of the Planning Assessment, as described in Requirement R2.4 ~~and Requirement R2.5~~, each Transmission Planner and Planning Coordinator shall perform the Contingency analyses listed in Table ~~2~~1 ~~– Stability Performance~~. The studies shall be based on computer simulations using models utilizing data provided in Requirement R1. ~~The studies shall be based on computer simulations using models utilizing data provided in Requirements R9 through R14, the MOD-010 and MOD-012 standards, and other data sources, to include known planned and long term outages of Transmission or generation equipment. The studies shall cover both System Stability and Generating Unit Stability. The following requirements apply to both System Stability and Generating Unit Stability studies unless otherwise noted.~~

P. Requirement R5.3 has been modified to address simulation of how generators perform under conditions being studied. The current MOD standards that address steady-state and dynamic simulation data requirements do not explicitly require the Generator Operators to provide voltage ride-through capability.

Organization	Question 15:	Question 15 Comments:
These standards are set to be addressed by Project 2010-04 within NERC's Standards Development Work Plan. It is expected that the Transmission Planner would contact Generator Operators applicable to their System to obtain such data. If the data is not provided, it would be expected that a Transmission Planner state its assumption on the Vmin used for a generator terminal voltage for assessing ride-through capability. It's likely such information could be obtained through generator manufacturers. The "Other equipment" is addressed in the revised R5.4. Q. The SDT agrees and therefore has changed R1.1.1 to state "if specifically known." R. FERC order 693 (see paragraphs 342, 1792, 1794) suggests that Non-Consequential Load loss for single Contingencies is unacceptable. Note from paragraph 1792 of order 693: "We view these arguments as based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The fact that the table allows Load loss for some "lower probability" N-1 events (some P2 events) for any Transmission voltage is recognition by the SDT that probability impacts both costs and practicality. S. The SDT believes that a current study is a study that has been completed for the latest Assessment, as opposed to a past study that may have been completed up to five years ago.		
NSTAR Electric	B — Unsure about supporting the revised standard	Aside from the comments to the prior questions, listed below are several others issues: 1. This standard does not address base conditions regarding generation dispatch and transfers across the system. Initial condition guidelines would be very important to establishing consistent application of the performance standards. 2. This standard should allow exceptions for loss of small parts of the system as long as reliability is maintained on the interconnected BES. There is such an allowance in the existing TPL standards in Table 1, footnotes b) and c). 3. The reference to Special Protection Systems is too permissive. The use of Special Protection Systems and their inherent complexity should be restricted to ensure a reliable system and to promote construction of needed infrastructure. 4. The Long-Term Planning Horizon should be limited to 10 years, a sufficient timeframe to identify requirements that may take an extended time to implement. 5. Definition of Planning Coordinator is part of the NERC Functional Model. It should be removed from the TPL standard. 6. Put headings on each section to identify the requirements of the section. 7. With respect to R2.2, delete "current" from the phrase "current System Peak Load Study" and replace "Study" with "Assessment." 8. R3.3.2 should be changed to permit discretion regarding the single contingencies that need to be tested, similar to R3.3.3 and R3.4. It is unnecessary to test all possible events. 9. R3.2.1 should be clarified as to whether the intent of the standard is to address station service minimum voltage

Organization	Question 15:	Question 15 Comments:
		limitation, maximum leading VAR absorption capability or both. 10. Remove R3.2.2. Relay loadibility is addressed in the PRC-023 Standard. 11. In R3.3.2.1, remove the requirement to assess the expected duration of Consequential Load loss. This requirement is unnecessary and not considered anywhere else in the standard. 12. With respect to R3.3.3, the paragraph refers to Table 1 Contingencies P3 through P7; this should be explicitly stated. Also, the rationale for inclusion of testing should not be required. It only makes sense to explain why certain Contingencies were not tested. This discretion should be applicable to all contingencies in all sections of the standard.

Response: 1. The SDT has modified Requirement R1 to include additional details on what should be modeled in the cases. However, the SDT intentionally provides flexibility for the Transmission Planner/Planning Coordinator to decide which "base case" to use since initial conditions for a System will vary from region to region and will need to be established on a local level, not via a national standard. The required studies and sensitivity analysis ensures that sufficient study is performed to cover an appropriate range of System conditions.

2. Some commenters expressed concern with the inability to shed Non-Consequential Load in response to a single Contingency event. It was indicated that some stakeholders rely on an SPS to drop local area network Load in response to some single Contingency events and that these System designs are permissible under the presently approved TPL-002-0 standard. FERC in Order 693 was clear in paragraph 1794 that 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 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. As an alternative, an entity could seek an Entity Variance for the situation described through their Regional Entity organization. In paragraph 1794 FERC clarified that "…an entity may seek a regional difference to the Reliability Standard from the ERO for case-specific circumstances". The process described by FERC as a regional difference is described in detail in the "NERC Standards Development Procedure" document under the subsection titled "Variances to NERC Reliability Standards".

3. The SDT does not believe that it would be appropriate to attempt to specify limitations to the use of Special Protection Systems in this standard. The proposed TPL-001-1 and existing standards provide adequate guidance to the industry on application of Special Protection Systems.

4. The SDT believes that a review of System conditions beyond the 10-year horizon is warranted. FERC Order 693 requires that the planning horizon take into account the lead times for siting and permitting of new long-distance Transmission lines and other long lead time solutions. The SDT has received industry comments regarding the need to exceed a 10-year horizon to account for longer lead time projects. Establishing planning horizons that are shorter than Transmission lead times may create gaps where the identification of a reliability need to which Transmission may be the best solution occurs too late to avert the identified reliability violation. Further, Operating Procedures or alternative short-term capital projects may be needed to limit the impact of the Planning Event until the planned Facilities can be completed. This information needs to be included in the Assessment.

5. The definition for Planning Coordinator was deleted because the term has already been defined and added to the NERC Glossary by another SDT.

6. The SDT has considered this action but NERC's legal staff advised against using headings in the body of standards.

Organization	Question 15:	Question 15 Comments:
7. The SDT believes that the existing language is appropriate. 8. The SDT has removed the Requirement R3.3.2 and replaced it with additional language in Requirement R3.1. The SDT does agree with your interpretation that it does not require evaluation of all single Contingencies. The SDT specifically states in Requirement R3.4 that those Contingencies that are expected to produce the more severe System impacts shall be identified, evaluated for System performance, and the rationale for the Contingencies selected for evaluation shall be available as supporting information and shall include an explanation of why the remaining Contingencies would produce less severe results. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.4. 9. The SDT has not limited the purpose of this requirement to either minimum acceptable station service voltages or maximum Mvar absorption. The SDT believes that the purpose of Requirement R3.2.1 (now R3.3.2) is to determine if generators could continue to operate or if they would trip off following the contingency. 10. The SDT believes that relay load limits or loadability need to be considered in the Contingency analyses. The studies should determine if Transmission line loadings could reach the relay loadability limits, which may add to the existing Contingency and perhaps, result in an unbounded cascading event. 11. To meet industry concern as well as FERC Order 693, the SDT has added Requirement R2.8 to identify the event causing the single largest Consequential Load Loss Demand and its value and eliminate the reporting of the expected duration. Requirement R3.3.2.1 has been removed from the draft. **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. 12. Although the implied assumption that the more severe impacts would be identified in the P3 through P7 Contingencies, there may be exceptions and the SDT does not believe it necessary to modify the language in this regard. The wording of new Requirement R3.~~5~~ 4 (the old Requirement R3.3.3) now requires a listing of the Contingencies to be evaluated, the rationale for their selection and why the remaining Contingencies would be expected to produce less severe results. This will provide a complete evaluation of the potential Contingencies to be studied – those selected and those excluded. **R3.4** Those Planning Event Contingencies in Table 1 ~~– Steady State Performance not covered in Requirement R3.3.2~~ 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 R3.1 created~~,~~. ~~and t~~The rationale for the Contingencies selected for evaluation shall be available as supporting information and shall ~~includ~~include~~e~~ an explanation of why the remaining Contingencies would produce less severe System results.		
SERC Reliability Review Subcommittee and Planning Standards Subcommittee		C. Definitely do not support the revised standard. A majority of SERC technical experts do not support the revised standard. The primary concern is that the need for additional requirements for planning 300kV systems and above has not been demonstrated. We do not believe that a sufficient case for ?raising the bar? has been provided and that this requirement can have a huge impact on utilities and ratepayers. R2.1.3 and R2.4.3 requirements are very prescriptive. Many examples of sensitivities are already inherent in the existing requirements. Some sensitivity studies are in effect adding an additional level of contingency (N-2 or N-3). Sensitivity studies of load variation are already inherent in the fact that several different study years and conditions are already being

Organization	Question 15:	Question 15 Comments:
		required. Outages of reactive sources and generation should already be included in studies of multiple contingencies. The process of planning new generation (system impact studies) will include studies of the future with and without the proposed new equipment. The TP and PC can better select the most appropriate sensitivities for their system. We recommend that engineering judgment continue to be recognized as a vital component of planning. Category P6 is the loss of a system element, followed by system adjustments, followed by the loss of another element. The table columns for this category say that interruption of firm transmission service is allowed. The table, however, is not clear whether the interruption of firm service is allowed as part of the system adjustment (between the outages) or whether it is only allowed after the second outage. It was stated in the NERC TPL SDT WebEx (August 26, 2008) that the interruption is not allowed as part of the system adjustment. This would be a dramatic change from the existing standard and would result in the unintended consequence of significantly reducing transmission system capability to accommodate firm transmission service including reduction of transfer capability of interfaces to a fraction of their currently reported capability. This would in effect be imposing an n-2 criteria for offering firm transmission service. This would not be an acceptable situation for the users, owners and operators of the bulk power system. Additional Comments: There is concern with load modeling requirements (use of word ?appropriately? in R2.4.1). Does this requirement mandate the use of specific load models for each bus, or would an aggregate load model which represents the system as a whole be sufficient? Does the use of the PSS/E CONL function satisfy the requirements for a load model? There is a concern that R3.3.2.1 is burdensome regarding the need to keep track of the quantity of consequential load loss and expected duration. Who is collecting this information and why is it needed? It appears that this is a local regulatory issue, not a reliability issue. There is a concern with R5.6.1 with the requirement to perform simulations on 20 MW generators (to be consistent with the Registration Criteria). We recommend a 75 MW generator cutoff for required simulations.

Response: The SDT is attempting to raise the bar by developing a standard that appropriately supports BES reliability and has industry consensus. The majority of the SDT believes that 300 kV is an appropriate cutoff and that Transmission Systems above this level represent backbone Systems and are part of regional "grids". The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations and has provided for flexibility in corrective action plans. FERC has noted in their orders that many of the concerns about raising the bar show more concern about economics than reliability (examples, Order 890, paragraph 423; Order 693, paragraph 1792, etc.).

The SDT agrees and have clarified the language to allow the Transmission Planner and Planning Coordinator to chose the sensitivities (Requirements R2.1.3 & R2.4.3)

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

<table>
<tr><th>Organization</th><th>Question 15:</th><th>Question 15 Comments:</th></tr>
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R2.4.3 For each of the studies described in Requirements R2.4.1 and ~~Requirement~~ R2.4.2, ~~s~~ensitivity case(s) that are intended to stress the System with variations ~~to reflect~~ in one or more of the following conditions not already included in the studies shall be ~~run and documentation of the technical rationale for why each of the conditions was or was not selected shall be supplied~~ included in the Assessment:
The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in the Revision 3 of the Standard provides clarification.
Footnote #10 – 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 be considered.
The SDT does not believe that specific Load models for each bus are necessary. An aggregate Load model which represents the System behavior as a whole may be used. Requirement R2.4.1 has been revised. The SDT does not believe that the use of PSS/E Activity CONL by itself provides the appropriate representation for dynamic Loads. For example, the SDT believes that using PSS/E Activity CONL is not sufficiently robust to appropriately model summer peak Loads with high concentrations of induction motors during for low voltage/motor stall conditions. A dynamic Load model such as CLOD, in conjunction with Activity CONL to model the non-induction motor load would be required to more accurately assess the system for FIDVR - Fault Induced Delayed Voltage Recovery.
R2.4.1 System peak Load for one of the five years. 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. An aggregate system Load model which represents the overall dynamic behavior of the Load is acceptable.
To meet industry concern as well as FERC Order 693, the SDT has deleted Requirement R3.3.2.1 and replaced it with Requirement R 2.8. The SDT believes that quantifying the single largest Consequential Load Loss and identifying the event causing it provides a useful metric for system performance and reliability.
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.
The requirement for study has been changed to 20 MW for a single generator or for an aggregate of generators. This language is now in Requirement R2.5.2.
R2.5.2 For steady state, short circuit, ~~Generating Plant Stability,~~ or ~~System~~ Stability analysis: the ~~study~~ 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:
</td></tr>
<tr><td>Oncor Electric Delivery</td><td>B — Unsure about supporting the revised</td><td>Initially performing outstanding tasks as well as annual maintenance of documentation and regular updates would require extreme significant resources both personal and financial. Transmission Planning to this level requires high level subject matter experts with both specific transmission system knowledge as well as overall industry experience. Considerable expense would also be required to train personal and track activities. The procurement documents necessary to interface</td></tr>
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Organization	Question 15:	Question 15 Comments:
	standard	with consultants in this area where "in house" expertise is not available would also be required. Time would also be spent on evaluating new software and analysis tools such as EPRI dynamic models. A phased in approach would be taken to complete the tasks while still performing essential Oncor and ERCOT related activities associated with System Planning.
Response: The SDT has received many comments regarding the increased planning requirements to meet the proposed standard. However, the SDT believes that the requirements for sensitivity studies must remain to satisfy FERC Order 693. FERC has stated that the sensitivity studies would be used to document the selection of critical System conditions and study years used in assessing System conditions (see paragraph 1704) and that System conditions are as important as Contingencies in evaluating the performance of present and future Systems (paragraph 1705). The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved and has considered them in its deliberations. The SDT is developing the Implementation Plan and will include it in the next draft of the standard		
FirstEnergy Corp.	A — Generally support the revised standard	1) For this standard, "Protection System" failure should be limited to only relay event failures. 2) R1 ? As stated in our response to Question 5, FE does not support the modeling requirements within the TPL standard and suggest that the SDT remove these requirements. This standard should be viewed on a premise that a valid and appropriate system model exist so that the fundamental focus of the standard is as stated in its purpose statement "Establish Transmission System planning performance requirements... to develop a Bulk Electric System that will operate reliably over a broad spectrum of System conditions." If R1 remains, the phrase "and other data sources" should be removed. 3) R1.1 ? this requirement requires the documentation of ANY data modification. Do you really mean ANY? How much detail is needed in the documentation? Is a line by line comparison of all data values before/after needed or is a general overview discussion sufficient? For instance, FE replaces its system model as shown in the MMWG representation with a more detailed system representation model when performing planning studies. This can included many differences from the MMWG system equivalent. How much documentation is needed in this situation? 4) R2.6 ? This is not a requirement and should be removed and shown as explanatory text (footnote). 5) R3 - Requirement R3.1 is redundant to statements in the text of R3 and R3.3 and R3.4. We suggest that R3.1 be removed. It is suggested that R3.4 be indented and become a R3.3 sub-requirement. R3.5 would be better placed ahead of R3.3 along with the existing R3.2.
Response: 1. The SDT believes that these protection issues will be further clarified by the NERC SPCTF drafting team. The spirit of the TPL standard will remain that Load loss must not be planned for any single failure. 2. The SDT has removed Requirements R9-R14 and enhanced Requirement R1 to more clearly specify the modeling information needed to support accurate Planning Assessments. **R1** Each Transmission Planner and Planning Coordinator shall maintain System models for performing the studies needed to complete their Planning		

Organization	Question 15:	Question 15 Comments:
Assessment. The models shall use data consistent with the data provided in accordance with ~~Requirements R9 through R14,~~ the MOD-010 and MOD-012 standards~~,~~ and other data sources,~~.~~ and shall simulate projected System conditions including requirements of regulatory authorities and other legal obligations. 3. The SDT agrees and has removed the need for documentation of the technical rationale for modification of any data. 4. The SDT disagrees and believes that the format and language of Requirement R2.6 (now R2.5) and its new sub-requirements are appropriate. 5. The SDT has modified the language of Requirement R3.1 and deleted Requirement R3.3 to eliminate the redundancy. **R3.1** Studies shall be performed to determine whether the BES meets the performance requirements in Table 1~~ – Steady State Performance.~~ based on the lists created in Requirement R3.5.		
Orlando Utilities Commission	C — Definitely do not support the revised standard	This standard is a definite improvement over the current set of standards. The majority of my comments are on details rather then the overall concept. My single biggest concern is the handling of n-1-1. This represents a significant expense to transmission customers and serious restriction on making firm transmission available, but due to the low probability of these events it would represent little if any practical improvement in customer reliability or grid security.
Response: Please see footnote #10 with regard to N-1-1. The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. **Footnote #10** – 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 be considered.		
Entergy Services, Inc.	C — Definitely do not support the revised standard	No cost-benefit studies have been completed to justify the significant investment and no detailed analysis of the expected reliability impact has been conducted for the Eastern Interconnection. Some research suggests that infrastructure expansion will reduce the number of large BES events, but that each event would impact larger areas with longer restoration times. http://eceserv0.ece.wisc.edu/~dobson/PAPERS/complexsystemsresearch.html Additionally, there is a fatal disconnect between the enhanced reliability standard and the FERC's current standard for selling firm transmission service. A utility cannot be required to build to an N-1-1 standard to satisfy reliability requirements and also be required to sell additional firm transmission service using a lower N-1 reliability standard. Such a situation would create an untenable situation where reliability standards force construction that the utility is then required to make available for sale pursuant to the provisions of the OATT and, once sold in accordance with the OATT, results in the utility being out of compliance with the reliability requirement. Requirement P2.1 in the table will have direct impact on local load reliability but not grid reliability. For example, a long line

Organization	Question 15:	Question 15 Comments:
		in a radial configuration due to a single contingency would only impact the reliability in a local area. Any implementation plan should consider all aspects of obstacles that Transmission owners will encounter including, ROW and land acquisition delays, inflationary impact on raw materials and other resources, capital funding constraints and associated regulatory lag, etc. Category P6 prescribes what is effectively an n-2 criteria for offering firm transmission service by not allowing the curtailment of firm transmission service as a system adjustment. Many areas are limited in how much local generation is available for re-dispatch as a system adjustment and thus compliance would be realized only by costly transmission construction by TPs.
Response: The SDT is striving to develop a standard that appropriately supports BES reliability and has industry consensus. The SDT is cognizant of the cost factors involved here and is taking them into consideration in its deliberations. The SDT agrees that clarification regarding Firm Transmission Service and Non-Consequential Load Loss is necessary. Footnote # 10 has been added to the end of Table 1: **Footnote #10** – 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 be considered. The SDT agrees that the Implementation Plan should consider matters you have listed. Nevertheless, the SDT feels that for this event (explained in detail in the footnote 8 of draft 3 of this Standard) interruption of neither firm nor Non-Consequential Load should be allowed for any BES voltage level, i.e., above or below 300 kV. This is consistent with FERC Order 693 that does not allow dropping Non-Consequential firm Load following any single Contingency. The SDT agrees that clarification regarding treatment of Firm Transmission Service and Non-Consequential Load Loss during adjustment is necessary. Footnote 10 in draft 3 of the Standard provides clarification.		
BPA Transmission Reliability Program	B — Unsure about supporting the revised standard	We are unsure about supporting the revised standard. A couple of additional concerns are described below. The purpose of the Standard is not clearly defined. There should be more clarity given to what reliability means in the context of these standards (e.g. minimize load loss for more probable contingencies, etc.). Regarding the terms "interruption of firm transmission service", there needs to be clarification of what "Interruption" means. Does it include curtailment needed after a particular contingency and adjustments? There also needs to be clarification on what "Firm Transmission Service" means. Two points: 1) the NERC definition states "highest quality of service offered to customers under a filed rate schedule that anticipates no planned interruption." The Standard implies anticipation of "unplanned' interruption for certain contingencies. 2) Is this referring to a transmission product as defined in FERC Order

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		890, or firm transfers modeled for the conditions being studied? One way to interpret the intent, is the firm transfers being modeled for the conditions in the powerflow, to meet demand that would result in load not being served if that firm transfer were curtailed. If there is other generation in the system that could increase to meet the load, if the transfer being modeled is interrupted, then interruption of firm transmission service should be allowed for P1 through P5 contingencies in the table.

Response: The SDT believes that the Purpose under A.3 adequately captures the main intent which is to develop a "Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies."

Footnote # 10 has been added to the end of Table 1 to reflect that curtailment or interruption of Firm Transmission Service will be allowed in preparation for the next Contingency. However, until the next Contingency occurs, System performance will need to meet the requirements for Event P1. As such, the proposed standard will not allow loss of any Non-Consequential Load, except for contracted Interruptible Loads, in preparation for the next Contingency. "Firm Transmission Service" is a NERC defined term and is also addressed by FERC in OATT.

Footnote #10 – 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 be considered.

Organization	Question 15:	Question 15 Comments:
PPL EnergyPlus	A — Generally support the revised standard	

Response: Thank you for your support.