NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Informal Comments on Assess Transmission Future Needs – Project 2006-02.

The TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02) Drafting Team thanks all commenters who submitted comments on the fifth draft overview. These standards were posted for a 30-day public comment period from August 3, 2010 through September 2, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 7 sets of comments, including comments from 77 different people from approximately 69 companies representing 6 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

The SDT has completed the review of the informal comments from industry for Project 2006-02: Assess Transmission Future Needs. Each and every comment was reviewed and considered by the SDT regardless of whether there is a formal written response shown. The majority of the cases where the SDT did not make a change or provide a written response was because the SDT had already responded to the issue or the SDT did not believe that the proposed revision added clarity or otherwise improved the quality of the proposed standard.

The SDT made a number of changes due to the comments received from industry and drafting team discussions arising from those comments as highlighted below:

- Year One definition – deleted 'must'
- Conforming changes to the language in the Effective Date – made language consistent with the Implementation Plan
- Requirement R1 and M1 – changed, ". . . the latest data consistent with . . ." to "data consistent with. . . " and established P0 as normal System condition in Table 1
- Requirement R2, part 2.1.4 – replaced 'performance' with 'System response' and changed last bullet from ". . . planned Transmission outages" to ". . . known Transmission outages"
- Requirement R2, part 2.6.2 – require documentation explaining material changes
- Requirement R2, part 2.7.1 – made it clear that statement is not all inclusive
- Requirement R2, part 2.8.2 – made language consistent with Requirement R2, part 2.7.4
- Requirement R4, part 4.3.1, bullet #1 – added qualifier for high speed reclosing
- Requirement R6 and M6 and data retention for R6 – changed 'any' to 'the'
- Table 1, header note 'i' – deleted 'including Load'
- Table 1, P0 – delete superscript in column 6
- Table 1, P2 – added 'Breaker' to description
- Table 1, P4 – added 'Breaker' to description
- Table 1, P5: added 'non-redundant'
- Table 1, extreme events – Stability: made language consistent with Table 1, P5
- Measure M8 – spelled out the functional entity involved
- Data retention for Requirement R7 – deleted 'all such'
- Changed, "Initial System Conditions" to "Initial Conditions" in column heading of Table 1 and Table 1 Note 9
- Deleted section, "Compliance Monitoring and Reset Timeframe as this is no longer included in the standard template.

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The SDT believes that with these changes, the industry concerns have been addressed except for Footnote 12 (content of existing footnote b). Until the issues with footnote 'b' in Project 2010-11: TPL Table 1 are resolved, the SDT will not request the Standards Committee to move the project to the ballot phase. This could mean that Project 2006-02 may sit in limbo for several months pending the outcome of the Project 2010-11 deliberations. So that industry can see what has transpired with regard to their comments on Project 2006-02, the SDT is requesting that the consideration of comments document, along with the redlined version of TPL-001-2 corresponding to those comment responses be posted immediately. In this way, the industry can see what the SDT has decided in response to comments while the content of the comments is still fresh in the minds of the commenters. The SDT encourages anyone reading the posted documents to reach out to members of the SDT for informal discussions of posted documents.

Once Project 2010-11 is resolved, the wording for footnote 'b' will be essentially copied to TPL-001-2. The SDT realizes that this cannot be a simple cut and paste due to format differences between the old standard and the revised TPL-001-2 and will take appropriate actions to make things fit correctly. Once this has been accomplished, the SDT expects to ask the Standards Committee to move Project 2006-02 to the ballot stage.

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, Herb Schrayshuen, at 609-452-8060 or at herb.schrayshuen@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

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
1.	Group	Mallory Huggins	NERC Staff										
2.	Group	Philip Kleckley	SERC Planning Standards Subcommittee	X		X		X					
3.	Group	Guy Zito	Northeast Power Coordinating Council										X
4.	Group	David Kiguel	Hydro One Networks Inc.	X		X							
5.	Group	Bob Cummings	Transmission Issues Subcommittee										
6.	Group	Robert Jones	SERC Dynamics Review Subcommittee	X									X
7.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee										X
8.	Group	Richard Kafka	Pepco Holdings, Inc - Affiliates	X		X		X	X				
9.	Group	Ben Li	IRC Standards Review Committee		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	**2**	**3**	**4**	**5**	**6**	**7**	**8**	**9**	**10**
10.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				
11.	Individual	Eric Mortenson	Exelon Transmission Planning	X									
12.	Individual	Andy Tillery	Southern Company	X		X							
13.	Individual	Steve Rueckert	Western Electricity Coordinating Council										X
14.	Individual	Jana Van Ness, Director Regulatory Compliance	Arizona Public Service Company	X		X		X					
15.	Individual	Brent.Ingebrigtson@eon-us.com	E.ON U.S.	X		X		X	X				
16.	Individual	Richard Becker	Florida Reliability Coordinating Council, Inc - Transmission Working Group	X	X	X	X						X
17.	Individual	Brandy A. Dunn	Western Area Power Administration	X					X				
18.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
19.	Individual	Ray Mason	ReliabilityFirst										X
20.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
21.	Individual	Catherine Mathews	NorthWestern Energy (NWMT)	X									
22.	Individual	Phuong Tran	Lakeland Electric	X		X		X					
23.	Individual	Tom Duane	PNM	X		X							

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
24.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				
25.	Individual	John Collins	Platte River Power Authority	X		X			X				
26.	Individual	Aaron Staley	Orlando Utilities Commission	X									
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Randi Woodward	Minnesota Power	X									
29.	Individual	Martin Bauer	US Bureau of Reclamation					X					
30.	Individual	Paul Rocha	CenterPoint Energy	X									
31.	Individual	Tim Ponseti, VP	TVA Transmission Planning & Compliance									X	
32.	Individual	Dan Rochester	Independent Electricity System Operator		X								
33.	Individual	Dilip Mahendra	SMUD	X		X	X	X					
34.	Individual	RoLynda Shumpert	South Carolina and Gas	X		X		X	X				
35.	Individual	Brian Keel	SRP	X									
36.	Individual	Darcy O'Connell	California ISO		X								
37.	Individual	Scott Inglebritson	Seattle City Light	X		X	X	X		X			
38.	Individual	Ean O'Neill	California Energy Commission									X	
39.	Individual	Kathleen Goodman	ISO New England Inc.		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
40.	Individual	Oscar Herrera	Los Angeles Department of Water and Power	X		X		X	X				
41.	Individual	Orlando A Ciniglio	Idaho Power Co	X		X							
42.	Individual	David Bradt	United Illuminating	X		X							
43.	Individual	John Sullivan	Ameren	X		X		X	X				
44.	Individual	Si Truc PHAN	Hydro-Quebec TransEnergie	X									
45.	Individual	Sergio Garza	LCRA TSC	X									
46.	Individual	Saurabh Saksena	National Grid	X		X							
47.	Individual	Charles Lawrence	American Transmission Company	X									
48.	Individual	Thad Ness	American Electric Power (AEP)	X		X		X	X				
49.	Individual	Bill Middaugh	Tri-State Generation & Transmission	X									
50.	Individual	David Miller	Lakeland Electric	X		X		X					
51.	Individual	Steve Stafford	GTC	X									
52.	Individual	Chifong Thomas	Pacific Gas and Electric Company	X		X		X					
53.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
54.	Individual	Christopher L. de	Consolidated Edison Co. of New York, Inc.	X									

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
		Graffenried											
55.	Individual	Spencer Tacke	Modesto Irrigation District			X	X						
56.	Individual	Alex Rost	NBSO		X								
57.	Individual	Curtis A. Beveridge	Central Maine Power Company	X									
58.	Individual	Darryl Curtis	Oncor Electric Delivery	X									
59.	Individual	Jeffrey McKinney	New York State Electric & Gas Corp	X									
60.	Individual	Bart White	Progress Energy	X		X		X	X				
61.	Group	L Zotter, M Morais, J Billo, J Conto, S Jue, JC Culberson, J Teixeira, G Gnanam, S Myers	ERCOT ISO		X								
62.	Individual	Gary Trent	Tucson Electric Power Company	X		X		X					
63.	Individual	Gregory Campoli	New York Independent System Operator		X								
64.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
65.	Individual	Terry Harbour	MidAmerican Energy	X									
66.	Individual	Catherine Koch	Puget Sound Energy	X									
67.	Individual	Joe Tarantino	Sacramento Municipal Utility District	X		X	X	X					

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
68.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
69.	Individual	John Mayhan	Omaha Public Power District	X		X		X	X				
70.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				

1. **The SDT has revised the Implementation Plan based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.**

Summary Consideration:

The majority of respondents agree with the changes to the Implementation Plan and no further changes to the Implementation Plan are deemed necessary.

The SDT fully realizes that Project 2010-11 (Table 1 - footnote "b") must reach resolution prior to finalizing TPL-001-2 and stated the same in the information attached with the fifth posting of Project 2006-02.

The SDT reviewed the comment on consistency of language in the Implementation Plan and the Roadmap and agrees with the comment. The paragraph under Effective Date in the standard has been changed accordingly.

> For 84 calendar months beginning the first day of the first calendar quarter following applicable regulatory approval, or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter 84 months after Board of Trustees adoption, Corrective Action Plans applying to the following categories of Contingencies and events identified in TPL-001-2, Table 1 are allowed to include Non-Consequential Load Loss and curtailment of Firm Transmission Service (in accordance with Requirement R2, Part 2.7.3.) that would not otherwise be permitted by the requirements of TPL-001-2:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments. In many of the cases relating to the comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

1.1.5 – "The SDT believes that the base cases should include any area interchange that is planned between utilities." In addition, non-firm transactions are not required to be modeled.

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account its spare equipment strategy for long lead time Equipment when assessing the performance of its System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

2.3/2.8 – "is intended for the Planning Coordinator and/or Transmission Planner to assess whether circuit breakers supporting the BES have interrupting capability for Faults that they will be expected to interrupt. Even though the effects of short circuit capability are localized and may be related to new planned Facilities, it is important to BES reliability."

3.4.1/4.4.1 – "The SDT has determined that it is necessary for the Planning Coordinator and Transmission Planner to coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list created." In addition, the SDT wants to make it clear that an entity is responsible for corrective actions on its own System.

4.3.1 – "does not require modeling of Protection System equipment. It just requires you to have simulations which include the effects of Protection System equipment operation. You don't have to specifically model a relay to simulate the effect of clearing a fault at 3 cycles. If you need to model a relay to capture its effect, then model that relay. And certainly engineering judgment should be used to determine which relay effects should be included in the simulations."

References to TPL-001-1 are a typo and will be cleaned up. The correct reference, as pointed out, is TPL-001-2.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc	No	Requirement R1 Part 1.1 and following states "System models shall represent:... 1.1.5. Known commitments for firm Transmission Service and Interchange. It was commented during a previous posting that 1.1.5 should be reworded to read: Known commitments for Firm Transmission Service, and, additionally, other types of transactions provided they have been demonstrated to not violate existing reliability constraints. The response was that "The SDT believes that the defined term 'Interchange' covers other transfers as described in your comment. No change made."It is agreed that known Interchanges should be modeled. However, it is imperative that existing reliability constraints not be violated in the process. That is, Interchange relating to economic transactions should not drive planning studies. Reliability related investments should not be driven by congestion related to economic transactions incorporated into planning models. Following is a preferred/revised wording: o 1.1.5. Known commitments for firm Transmission Service and Interchange. Interchange is meant to refer to energy transactions other than firm Transmission Service. While rigorous planning studies have been conducted to permit the uninterrupted implementation of firm Transmission Service without jeopardizing the reliable operation of the Interconnected System, other types of energy transaction only take place whenever system conditions permit them. They are usually of very short duration relative to planning assessment periods (usually spanning for a few hours to a few days) and deemed highly interruptible subject to reliability issues that may arise during operation of the system. In other words, the term Interchange refers to economic transactions that are permitted when the system is secure and there are reasonable reliability margins to effect dispatch changes to lower operating costs. As such, Interchange should not be reflected in system representation meant to assess system reliability in adherence to reliability criteria delineated in documents such as TPL-001.

Organization	Yes or No	Question 1 Comment
GDS Associates, Inc.	No	We disagree with the Implementation Plan and we suggest changes as follows:- The title should read “Implementation Plan for TPL-001-2”- With regards to the Prerequisite Approvals, NERC project #2010-11 still in progress (Table 1, Footnote ‘b’) must be implemented before this current TPL-001-2 standard gets implemented. However, while the 2010-11 NERC project does not define any of the new terms such as consequential / non-consequential load, the footnote ‘b’ cannot be just copied into the new standard (see TPL-001-2 standard Table 1, note 12). Note ‘b’ may further change to reflect the verbiage in the TPL-001-2 standard.- Not sure what is the intent of the last paragraph. While the proposed changes to Table 1, footnote ‘b’ are quite precise, are we still open a door to those entities that will continue to trip Non-Consequential Load and curtail Firm Transmission Service? If no penalties for such practices while the proposed standard allows a sufficient time frame to correct any deficiencies, then what is the point to all the effort behind the development of a new TPL standard?
SMUD		R2.7.1, last bullet: Please provide specifics on the types of acceptable ‘Corrective Actions’ covered by ‘rate applications and DSM’ and the planning horizon for which they are considered acceptable. As an alternative, NERC should develop a process by which what is considered acceptable is published and continuously updated. (With due apologies for not raising this point earlier).
Western Electricity Coordinating Council	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on various requirements not identified in the questions below; therefore, we have included our comments here: Requirement and 2.6 and 2.6.1: A study that is five years old is very likely to be out of date. The entity's BES may have not changed much in five years but the entity cannot be certain whether or not their neighbor’s system may have changed. Changes outside the immediate entity's system can impact results of studies within their system. Suggest that two years is a maximum that past studies should be allowed. Requirement 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means that a PC or TP must coordinate with others to identify contingencies on other Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or does it mean that the PC or TP must coordinate with others to identify contingencies on their System that the PC or TP must now include on their Contingency list to simulate and address any performance violations on other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to mitigate, if a contingency in one System causes a performance violation in another System. Requirement R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping

Organization	Yes or No	Question 1 Comment
		of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
Tucson Electric Power Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We have included additional comments here since we were not able to find a place to include comments on the following: Requirement R4; Requirement, Parts 2.1.5, 2.3, and 2.8; Requirement 3, Part 3.3.2; and Requirement 4, Parts 4.3.1and Part 4.3.2 Requirement 2, Part 2.1.5:The spare equipment strategy does not improve reliability performance. If an outage of a long lead time piece of equipment occurs, the system should still be able to operate in a reliable manner that meets the performance measures of Categories P3 and P6. If an entity cannot meet its performance requirements under this standard, a capital project is indicated. Spare equipment being available would not mitigate this need it only increases expenses until the item is needed. Requirement 2, Parts 2.3 and 2.8:Short circuit fault duty is a localized phenomena that is mainly impacted by the addition of new generation or transmission facilities. Due to proprietary concerns of generation and transmission interconnection requests, short circuit studies are performed in forums outside the annual Planning Assessment. Normally, these studies will be conducted before the projects can be included in regional base cases. As such, short circuit analysis should not be included in this Standard since it would provided limited benefit. Requirement 3, Part 3.3.2 and Requirement 4, Part 4.3.2Steady state response of dynamic control devices should also be included in the Part 3.3.2. and the list of possible devices included should be removed from Part 3.3.2 and 4.3.2. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring

Organization	Yes or No	Question 1 Comment
		the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
Western Area Power Administration	Yes	The whole bullet point section in the Effective Date section referring to Corrective Action Plans could be deleted and instead captured by Requirement R2.7.3. A seven year grace period is probably not favorable to FERC, and a better solution could be developed to meet industry needs. In R2.7.3, a possible example of "beyond the control of the Transmission Planner" could be that the physics of a significant percentage of induction motors in low inertia air-conditioning loads would tend to pull out for certain N-1 events. This may in significant part occur because such motors may have nearly no dynamic stability margin to withstand such N-1 events as close-in 3-phase faults with normal clearing during peak load conditions. So until the Transmission Planner has been able to institute changes in the industry to address the basic physics of such loads, this Requirement 2.7.3 would permit the use of such "Non-Consequential" Load Loss and curtailment of Firm Transmission Service. In this example, it may take longer than a seven year time period to fix the problem. On the other hand, some examples of Non-Consequential Load Loss could perhaps be mitigated in a shorter timeframe. Provided that an entity has a good technical justification and defined margin for “Non-Consequential” Load Loss or curtailment of Firm Transfers, then it may be acceptable. Requirement R2.7.3 seems to move in this direction. Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”.
NERC staff	Yes	NERC staff supports the change to allow Corrective Action Plans to include tripping of Non-Consequential Load and curtailment of Firm Transmission Service for 7 years. This seems long, but staff understands the stakeholder concern that it could take that long to plan, site, and construct facilities required for compliance with the standard.
SERC Dynamics Review	Yes	“The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Dynamics Review Subcommittee only and should not be construed as the

Organization	Yes or No	Question 1 Comment
Subcommittee		position of SERC Reliability Corporation, its board or its officers.”
Lakeland Electric	Yes	Shouldn’t the “Implementation Plan for TPL-001-1” document be for TPL-001-2? Also, “TPL-001-1” is referenced throughout the document.
FirstEnergy	Yes	We appreciate the effort of the standard drafting team and the changes reflected in the current draft of the TPL-001-1 standard. The changes are improvements that should move the standard towards greater industry consensus. The extended Implementation Plan aligns with suggestions in FE’s prior ballot comments. We support the Implementation Plan change made by the team.
US Bureau of Reclamation	Yes	With exception of the definitions.
TVA Transmission Planning & Compliance	Yes	TVA supports the change from five years to seven years for the implementation plan period.
Independent Electricity System Operator	Yes	We agree with this change. We further suggest that this change and the additional wording: “or in those jurisdictions where no regulatory approval is required on the first day of the first calendar quarter, 84 months after Board of Trustees adoption” be added to P. 3 of the standard that starts with “For 84 calendar months...” to be totally consistent.
Pacific Gas and Electric Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R3 or R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent “[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models”. As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: “Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response”. Section 3.4.1 and 4.4.1 require PCs and TPs to coordinate with adjacent PCs and TPs to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list. Please clarify whether this means 1) that a PC or TP must coordinate with others to identify contingencies on other

Organization	Yes or No	Question 1 Comment
		Systems that the PC or TP must now include on their Contingency list to simulate and address any performance violations on their own System, or 2) that the PC or TP must coordinate with others to identify contingencies on their System that this PC or TP must now include on their Contingency list to simulate and address any performance violations on the other Systems. In either case, the standard does not seem to clearly state what must be done, or whose responsibility it is to develop the corrective action plan, if a contingency in one System causes a performance violation in another System.
Puget Sound Energy Sacramento Municipal Utility District Modesto Irrigation District Los Angeles Department of Water and Power Idaho Power Co California Energy Commission SRP Platte River Power Authority PNM Arizona Public Service Company	Yes	We commend the SDT for its work to continue the improvement on the proposed TPL-001-1. We were not able to find a place to include comment on Requirement R4; therefore, we have included our comments here: Section R4.3.1, bullet point 3 requires the stability analyses to include the impact of subsequent "[t]ripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models". As written, this bullet could be interpreted as requiring the inclusion of these relay models in stability data bases. We do not have generic or actual relay models in our dynamics data bases for tripping line faults on lines and transformers represented. We represent actual relay response and tripping times of relays, communications, and breakers to faults in tripping transmission lines and transformers. Requiring the inclusion of generic or actual relay models for all relays that can trip lines and transformers would add a large burden to the development and maintenance of accurate dynamics model files that would add little or no benefit. Please change this bullet to read: "Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on known Protection System response".
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review	Yes	

Organization	Yes or No	Question 1 Comment
Committee		
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
United Illuminating	Yes	

Organization	Yes or No	Question 1 Comment
Ameren	Yes	
Xcel Energy	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Northeast Utilities	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Southern California Edison Company	Yes	

2. The SDT has revised the definition of Year One based on industry comments to the initial ballot. Do you support this change? If you do not support this change, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The majority of respondents agree with the changes to the Year One definition but there was one change made due to industry comments for consistency of terminology.

Year One: The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing. For the Planning Assessment started in a given calendar year, Year One ~~must~~ includes the forecasted peak Load period for one of the following two calendar years. For example, if a Planning Assessment was started in 2011, then Year One ~~must~~ includes the forecasted peak Load period for either 2012 or 2013.

The SDT acknowledges the concerns expressed by a minority of commenters on ambiguity of wording, embedding the definition in the requirements, and use of operating horizon studies. However, the SDT believes that the definition has been vetted through numerous industry comment periods and that it now represents a reasonable definition for a continent-wide standard while still providing a level of flexibility for the planner.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 2 Comment
Northeast Power Coordinating Council	No	The definition of Year One could be eliminated, and its wording used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated. Define Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment.
ISO New England Inc.	No	The definition of Year One could be deleted and used in place of Year One within the text of the requirement. The proposed definition has now added ambiguity with respect to “year two” and “year five” which are not defined. Year two could be deleted and R.2.1.1 modified as follows: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.

Organization	Yes or No	Question 2 Comment
Western Electricity Coordinating Council	No	We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season's operating study as its Year One planning study. For example, if the entity does its study in the fall of 2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
E.ON U.S.	No	Comments: 2.2.1. A current study assessing expected System peak Load conditions for one of the years in the Long-Term Transmission Planning Horizon and the rationale for why that year was selected. E.ON U.S. believes the scope of the 'current study' should be defined. It is not clear whether the scope is the same as outlined in section 2.1.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, because it is worded to be dependent upon when an assessment is started rather than when the assessment is completed and valid. Assessments don't typically include a "start date". An assessment completed on a calendar date should include (be valid for) the forecasted peak load for a timeframe that begins no more than 24 months from the date that the assessment was completed.
Lakeland Electric	No	"the latest" is not needed from the second sentence of R1, since the sentence already ended with "..shall represent projected System conditions". R1 Part 1.1.2 Suggest adding this clarification at the end "... six months during the period under study". This language addition helps clarify the point that if an outage occurs during the summer and the entity's system peak occurs in the winter, then the system peak Load study case (model) does not have to include this particular outage.
Seattle City Light	No	The definition of Year One is now too flexible and does not meet the intent of the standard. For example, our system peak is generally in January of the year. If I perform TPL studies in November 2011, studying the peak in January 2012 is acceptable according to the new definition. This is only two months from the date of the study. The intent of the TPL standard should be that entities must study and plan for inadequacies found in the studies. A one- or two-month lead time is not adequate to address any problems identified. Year One should be the year containing the first peak 12 months or more from the current date. Otherwise, TPL studies become merely seasonal operational studies, not planning studies. Alternative Language: "For the Planning Assessment started in a given year, Year One should contain the first system peak that occurs twelve months or more after the date

Organization	Yes or No	Question 2 Comment
		of the Planning Assessment."
US Bureau of Reclamation	No	The language implies a requirement. The language "Year One must include the forecasted peak Load period for one of the following two calendar years" is a requirement and not a statement of clarification. If the definition is that "Year One" can also be the period used for forecast peak load, then it should be stated so. It is suggested that either the language in the definition is modified or the language is deleted from the definition and moved to the body of the standard.
United Illuminating	No	Year One should be used within the text of the requirement. Do not have a definition for Year One.
National Grid	No	Year One should be used within the text of the requirement. Do not have a definition for Year One. Year two could be deleted and R.2.1.1 modified as follows: For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied.
Tri-State Generation & Transmission	No	Comments: The Year One definition is somewhat clearer now, but there is still some ambiguity. We recommend the removal of the term "Year One, year two, and year five" from R2.1.1. and deletion of the Year One definition (definitions are not required for year two and year five, for instance). The Year One concept can be integrated into the definition of Near-Term Transmission Planning Horizon, which we suggest changing to "The period beginning with the first year following the operating horizon, as determined by the Transmission Planner or Planning Coordinator, through the fifth year." Then, rather than say "Year One, year two, and year five", we can use the phrase "at least one of the first two years of the Near-Term Transmission Planning Horizon, and the fifth year".This will require corresponding changes in R2.1.1 and R2.1.2.
Lakeland Electric	No	While the definition of Year One addresses the time span this year occupies, it does not address when that time span begins. The example which was added to the definition suggests that Year One begins twelve months from the start of the Planning Assessment, but it does not appear to be specifically stated. The following language is recommended: "The first twelve month period that a Planning Coordinator or a Transmission Planner is responsible for assessing, beginning twelve months from the planned completion date of the Planning Assessment."
Northeast Utilities Consolidated Edison Co. of New York, Inc.	No	NU does not support the revised definition of Year One as we believe it leads to confusion. Our suggestion is that Year One should be the Peak Load Year after the study is initiated. The subsequent years should be counted from Year One (e.g., a study that is started in year 2010 with peak load in 2011 will have Year One as

Organization	Yes or No	Question 2 Comment
		2011 and Year Two as 2012, etc.).
Modesto Irrigation District	No	The definition as it is in the current standards is fine. The new proposed definition is unclear.
NBSO	No	To avoid confusion, the formal definition for Year One should be eliminated and wording used to describe Year One be placed within the appropriate requirement. For example, R2.1.1 could be re-written to state: System peak Load representing a point in time 12-24 months and another point in time 48-65 months into the future from the time the study is initiated.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	The added clarification to the definition of Year One serves to remove most ambiguity with respect to Year One. However, the revision has added further ambiguity to the terms “year two” and “year five” which are not defined. For the Planning Assessment started in a given calendar year, the first year that is studied must include the forecasted peak Load period for one of the following two calendar years. An additional Near-term study must be performed that is four calendar years beyond the first year that is studied. We recommend defining Year Five as the twelve month period 4 to 6 calendar years from the date of the Planning Assessment. We further recommend revising R2.1.1 as follows: “System peak Load for Year One and for Year Five.”Alternatively, the definition of Year One could be eliminated and described within the text of the requirements.
Tucson Electric Power Company	No	A seasonal reference should be included in the example. Alternative language beginning with the second sentence: For the Planning Assessment started in a given calendar year, Year One must include the forecasted peak load period for the forecasted peak load season that is between 12 and 24 months into the future from the current season. For example, if a Planning Assessment was started in 2011 prior to the forecasted peak season, then Year One must include the forecasted peak load for 2012. If the Planning Assessment was started in 2011 during or after the forecasted peak season, then Year One must include the forecasted peak load for 2013.
GDS Associates, Inc.	No	The definition it seem both incomplete and exhaustive:- If taken out of the planning assessment context, the definition is missing the matter that is supposed to identify. We suggest changing the first sentence such as “The first twelve month period to which the functional entity is responsible for the assessment of Transmission System Planning performance.”- While it will be a burdensome task to define each year that follows Year One, the definition of Year One may include a sentence that define the rule for the following years such as “All of the twelve months period following Year One shall commence immediately after the end of the preceding twelve months period.”- The definition should not include examples.
Pacific Gas and Electric Company		We recognize that the drafting team made changes to the definition of Year One based on industry comments. However, we believe that the revised language could allow for a situation where an entity could use its next season’s operating study as its Year One planning study. For example, if the entity does its study in the fall of

Organization	Yes or No	Question 2 Comment
		2011, the proposed definition would allow the entity to use its summer 2012 operating study as its Year One study. This is a very short period to address any issued identified. Suggest working into the requirement that Planning Studies must look out at least 12 months beyond when the study is performed. This would still allow for the provision in the current definition example ("if a Planning Assessment was started in 2011, then Year One must include the forecasted peak Load period for either 2012 or 2013) because the entity would be able to use their 2013 Load period, but it would prevent the entity from using the 2012 Load period if they started the assessment late in 2011.
NERC staff	Yes	NERC staff supports the revisions to the definition of Year One. However, we believe an associated change should be made where this term is used in part 2.1.1 of Requirement 2 which requires modeling of "System peak Load for either Year One or year two, and for year five." It seems the new definition of Year One would negate the need to refer to year two. NERC staff recommends that part 2.1.1 be changed to "System peak Load for Year One and for year five."
Western Area Power Administration	Yes	Yes, this clarification helps. The drafting team could also define "year five".
FirstEnergy	Yes	The change in the Year One definition provides greater flexibility for the industry and also addresses a prior FE comment during the 1st ballot. We appreciate the team's careful consideration of the industry feedback and support the change.
TVA Transmission Planning & Compliance	Yes	TVA supports the change in the Year One definition - but would suggest that the word "started" should be changed to "completed" since a Planning Assessment may be started in one calendar year and finished in the next calendar year.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 2 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 2 Comment
SRP	Yes	
California ISO	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 2 Comment
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.

The SDT has revised the Requirements language based on industry comments to the initial ballot. Do you support these changes? If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

Due to various industry comments, the SDT made the following clarifying change to Requirement R1:

R1. Each Transmission Planner and Planning Coordinator shall maintain System models within its respective area for performing the studies needed to complete its Planning Assessment. The models shall use ~~the latest~~ data consistent with that provided in accordance with the MOD-010 and MOD-012 standards, supplemented by other sources as needed, including items represented in the Corrective Action Plan, and shall represent projected System conditions. This establishes P0 as the normal ~~s~~System condition in Table 1.

The SDT believes that 6 months is the correct number in Requirement R1, Part 1.1.2 because the planner is evaluating longer term periods, and shorter duration outages, which have scheduling flexibility, are addressed by Operations Planning. Outages six months or longer will typically be over the study periods (peak and Off-Peak) addressed in Requirement R2, Part 2.1.3.

Requirement R1, Part 1.1.6 – An issue was raised that resources could be used for export to other areas. The SDT did not make a change to the requirement since exports to other areas are covered in Requirement R1, Part 1.1.5.

The majority of respondents agree with the posted changes to these requirements and no other changes have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 3 Comment
NERC staff	No	NERC staff suggests that the added sentence in R1 be deleted and “Normal System” in Table 1 be replaced with “No unplanned Element outages.” We have a problem with R1 establishing “normal system condition.” “Normal” is not defined, but the system condition that most people would define as “normal” is the System operating within its limits. There are no checks required on the projected system conditions to guarantee “operation within limits.” Staff realizes that if this were the case, the categories tested would all pass their respective tests. (In other words, the category tests may define operating limits that in turn define “normal” from a planning perspective.) Thus, the added sentence in R1 should be deleted. In Table 1, the use of the term “Normal System” in the column “Initial System Condition” really means “No unplanned Element outages.” All Elements that do not have a planned outage are assumed in-service (for transmission Elements) or available for dispatch (for generators).

Organization	Yes or No	Question 3 Comment
		Contrast the term “Normal System” with categories P3 and P6, which have the loss of an Element (which is unplanned) followed by the loss of a second Element (also unplanned). “Normal System” should be replaced with “No unplanned Element outages.”
SERC Planning Standards Subcommittee Southern Company Ameren	No	The definition does not adequately address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (perhaps as R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring.
Bonneville Power Administration	No	Please clarify R1.1.2 to state “Known outage(s) of generation or Transmission Facility(ies) during the Planning Horizon with a duration of of at least six months.”
E.ON U.S.	No	In the statement: “the Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their Systems are included in the Contingency list.”E.ON U.S. believes that the use of the pronoun “their” in the quoted section above is confusing. “Their” could be read as applying to the adjacent Planning Coordinators and not to the Planning Coordinator to whom the standard applies. E.ON U.S. recommends that the word “their” should be changed to “the Planning Coordinator’s and Transmission Planner’s” in order to make it clear.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Since “the latest” data may become available after the study is complete, a planner may not be able to ever complete a study. Please consider removing “the latest” from the second sentence.
Western Area Power Administration	No	It’s difficult to tell whether Requirement R1 is intended to require only one base case or whether it was intended to require creation of separate models for each possible N-0 condition (“normal system condition”) under a variety of stressing scenarios. The inserted language does not seem to provide additional clarity. Suggested language may be “This establishes the initial 'Normal System' condition corresponding to category P0 in Table 1.” Also, in Requirement R1.1.5, how are the Firm Transmission Service commitments supposed to be modeled in Power Flow Cases? Are they just to be modeled as loads, generation, and control area interchanges? Suppose a POR or POD is not at a generator or load bus. What selection of generation and load would represent the projected system conditions for this Firm Transmission Service commitment?
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comment regarding R1; therefore, CenterPoint Energy's concerns remain.

Organization	Yes or No	Question 3 Comment
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp	No	For R1 Ambiguity regarding base case assumptions, in combination with lack of clarity and clear direction of purpose regarding the sensitivity analysis, undermines the objectives of the standard; R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
ISO New England Inc.	No	R1.1 Part 1.1.2. With respect to known outages, there needs to be greater flexibility in the standards (e.g. more tolerance to non-consequential load shedding or limitations to the contingencies that need to be considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be approved. Duration of known outages should be increased from six months to one year; R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load.
American Transmission Company	No	We propose the following changes and questions: R1 - We offer the minor suggestion of replacing the wording of “maintain System models within their respective areas” with “maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC”. This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP’s geographic area, but expects its primary TP to maintain the BA’s model data for the remote generation or load. R1.1.2 - We request a SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Tri-State Generation & Transmission	No	We suggest changing the added sentence to “This establishes the Category P0, No Contingency, Initial System Conditions in Table 1.”
Lakeland Electric	No	Consider removing “...the latest...” from R1 and changing R1.1.2 to state “...six months during the period of

Organization	Yes or No	Question 3 Comment
		study."
Northeast Utilities	No	NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. More guidelines for developing base cases should be addressed in the requirements. What the statement in Requirement R1 lacks is the manner of creating generation dispatches and the level of interface flows (level of stress), which are central to any base case to be used to assess the reliability of the electric power network. Depending upon how the base case dispatches and the level of interface flows are created, a study may reveal reliability violations in the power system. This is a weakness of the existing TPL standards. NU, however, will support the idea of developing regional guidelines in regard to the nature of the base cases to be used for the NERC reliability studies. Comment on Requirement R1.1, Part 1.1.2: With respect to known outages NU requests that the six month duration listed by the requirement should be changed to one year duration. Requirement R1.1 Part 1.1.6: The phrase "required for Load" should be deleted as this confuses the issue [since resources may also be used for export to other areas and not just internal load].
NBSO	No	R1 should have some language to state that base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice.
Tucson Electric Power Company	No	Proposed changes1.1.1 Existing Facilities that will not be changed before the study year 1.1.3 New planned Facilities and planned changes to existing facilities
GDS Associates, Inc.	No	The Time Horizon should be for both Near-Term and Long-Term Planning.
MidAmerican Energy	No	There are concerns over the FERC outstanding March order on TPL and how FERC interprets "normal" or base case conditions and "assuming" an entities primary protection system is out of service and must rely on its backup protection system to operate. This concept combined with the new tables cannot be perpetuated.
Xcel Energy	No	Although we support the change conceptually, we believe the sentence added in R1 needs more specificity to ensure a better correlation to the relevant portions of Table 1. Please make it clear that the system model created as per R1 corresponds to Category P0 by explicitly referring to it. Suggested language is: 'This establishes the "Normal System" initial condition corresponding to category P0 in Table 1.' Further, consider omitting the word "System" in Table 1 Column 2 heading by calling it "Initial Condition" – the redundancy produced by its usage in both heading and entry does not appear to provide any

Organization	Yes or No	Question 3 Comment
		value. Alternative suggested language is: 'This establishes the "Normal" initial system condition corresponding to category P0 in Table 1." This alternative approach envisages changing the Column 2 entries to "Normal" since the word "System" is now retained in the heading.
MRO's NERC Standards Review Subcommittee	Yes	We propose the following changes and questions:R1 - We offer the minor suggestion of replacing the wording of "maintain System models within their respective areas" with "maintain System models of elements that are interconnected to any portion of the BES that is owned or operated by the TP or PC". This wording would avoid the ambiguity that can occur when a BA that is associated primarily with one TP declares ownership of a bus in another TP's geographic area, but expects its primary TP to maintain the BA's model data for the remote generation or load. R1.1.2 - We request the SDT opinion on how two individual outages should be modeled if they are both in excess of six months duration and they overlap by less than six months. Should the overlapping condition only be modeled if the condition is expected to last more than six months?
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
Transmission Issues Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	

Organization	Yes or No	Question 3 Comment
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
US Bureau of Reclamation	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	

Organization	Yes or No	Question 3 Comment
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
ERCOT ISO	Yes	
New York Independent System	Yes	

Organization	Yes or No	Question 3 Comment
Operator		
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.1 Requirement R2 and Part 2.1 – past studies

Summary Consideration:

The majority of respondents agree with the changes to these requirements and only the changes to these requirements noted below have been made.

The SDT believes that the supposed inconsistencies mentioned in the language are not inconsistencies at all but necessary qualifiers. No change made.

Based on comments received, the SDT has modified Requirement R2, part 2.6.2 as follows to provide additional clarity:

> **2.6.2** For steady state, short circuit, or Stability analysis: no material changes have occurred to the System represented in the study. ~~shall not include any material changes unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area.~~ Documentation to support the technical rationale for determining material changes shall be included.

The following change was made to clarify that the list following the statement is not all inclusive:

> **2.7.1** List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered them. In some of the cases relating to the above comments, the SDT has already responded to similar comments and those responses are quoted here for convenience:

2.1.5 – "When a piece of long lead-time Equipment is unavailable, System adjustments will need to be made. The System, after it is adjusted to accommodate that piece of Equipment out of service will be treated as the "normal" (P0) condition in Table 1 and the rest of Table 1 will be applied as stated. This requirement is intended for the Planning Coordinator and/or Transmission Planner to take into account their spare equipment strategy for long lead time Equipment when assessing the performance of their System. If the loss of a piece of major Equipment can be replaced within a reasonable period of time, planning studies for the following year can assume that that piece of Equipment will be replaced. If not, its impact of unavailability would need to be assessed. Actions such as out of merit dispatch, operational restrictions, System reconfiguration can be part of a Corrective Action Plan if the System cannot meet performance requirements without the Facility in service."

Organization	Yes or No	Question 4 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. This revision must be carried through to other sections (R2.2, 2.2.1). However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part 2.2 should be modified to similarly read as Requirement R2, Part 2.1. Regarding R2.2, the language should be consistent with 2.1. For example, use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than was originally drafted. This would require the PC & TP to study (meaning performing a technical analysis) of the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6). R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list, and also suggest revising to “Such actions may include but not be limited to:”.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	No, Please consider removing R.2.6.2. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive.
Western Area Power Administration	No	R 2.1.5: The issue in this Requirement is studied in the Operations next-day; next-week; next-month studies required under the TOP Standards; and are also covered by processes such as the Operational Transfer Capability Policy Committee (OTCPC) seasonal study process within the WECC. It would be quite onerous to run a complete power flow simulation on separate base cases for each transformer (or other equipment with long lead time) initially out of service. The revision in language from “Planning Assessment” to “studies” does not clarify that a power flow simulation is not necessarily required for each situation. A valid assessment could include other methods such as using sound technical reasoning to relate the initial out-of-service

Organization	Yes or No	Question 4 Comment
		condition to a condition that has already been studied. This condition may have taken place in previous operational studies. The language in the standard could be improved to make this clarification - perhaps reference R2.6. Additionally, this Requirement still needs further clarification. Currently the scope of equipment applicable to the requirement could be misinterpreted as larger than that contemplated by FERC. The standard as written seems to say that the responsible entity needs to study the spare equipment strategy for all "major transmission equipment" with long lead times. In the directive to include this requirement, FERC used the term "critical facilities". In the NOPR to Order No. 693 they stated, "Critical facilities are those facilities that impact IROLs and deliverability of generation to firm load" (P1081). In Order No. 693 FERC also said, "if an entity's spare equipment strategy for the permanent loss of a transformer is to use a 'hot spare' or to relocate a transformer from another location in a timely manner, the outage of the transformer need not be assessed under peak system conditions" (P1725).Finally, the drafting team could clarify if this requirement applies to radial branches (such as generator step-ups or step-down to load). Such branches may be construed as "critical facilities" but the impediment to deliverability of generation to firm load is consequential to the initial outage.
Lakeland Electric	No	Please consider removing R.2.6.2
Platte River Power Authority	No	I like that you have requirements for qualifying past studies, but Part 2.6.2 is confusing. Please change Part 2.6.2 to read something like: "For steady state, short circuit or Stability analysis: no material changes have occurred to the System represented in the study or, if material changes have occurred, a technical rationale can be provided to explain that the changes do not impact the performance results in the study area."
Orlando Utilities Commission	No	Allowing the use of past studies in lieu of new studies for part or all of an assessment when the underlying system hasn't changed in a signficant change if very prudent. However the wording in 2.6.2 of "unless a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area" is of concern. By this wording is it intended that the planner must demonstrate that every material change has no impact? In essence doing more work to prove that a study isn't required then the study would take? Or that the planner must essentially have a technical rationale (overarching) for determining when a material change is "material enough" to impact system perofrmance?
Minnesota Power	No	Requirement 2 - This requirement states that Stability analyses be performed as part of the annual Planning Assessments. Minnesota Power would like to see the term "Stability analysis" more clearly defined as there are several different types of stability related analysis that can be performed for power systems including: transient stability, voltage stability and small signal stability.
US Bureau of Reclamation	No	The question is misleading in that R2 also include current studies. The overall structure of the standard

Organization	Yes or No	Question 4 Comment
		could be greatly improved if the standard were segmented into Near Term and Long Term with sub segments for each specific type of analysis to be performed. Second, the standard does not use consistent terms. The Planning Assessment is to include Near Term and Long Term portions which must have steady state analysis, short circuit analysis, and stability analysis (ref. R2). Requirement R 2.1 introduces sensitivity analysis for the Near Term portion, and then refers to the Planning Analysis which is in reality both Near Term and Long Term portions. That implies that sensitivity analysis must be required for both? The standard repeats the requirement for annual stability studies in 2.4 which was already a requirement for Planning Assessments. The requirement 2.1.5 is one the most problematic requirements in this standard. This requirement implies that an entity must have spare equipment and a strategy to employ it. That is beyond the scope of the Energy Policy Act 2005. Spare equipment is not on-line and does not contribute to the reliability of the existing system. The Energy Policy Act of 2005 specifically prohibits the requirement to enhance or modify the system. The use, application, or requirement to have spare equipment violates that prohibition. This section should be removed. In addition, this requirement suffers from an ability to implement. In the first case, the requirement is invoked if the spare equipment strategy could result in unavailability of transmission equipment. How is that determined? There is no nexus to that determination. The unavailability may have already occurred once the transmission equipment has failed. The only way to avoid unavailability if the transmission equipment that fails has a hot stand-by with automatic fail-over. The presence or not of a suitable replacement will still result in unavailability by virtue of the failure o the first piece of transmission equipment. Next problem, who will second guess the owner of the replacement. Where is the requirement to make the replacement strategy available? The standard should focus on system performance with existing equipment to meet current and future loads.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
ISO New England Inc. United Illuminating National Grid	No	We can agree with R2.1 however with respect to R2.2 Language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study."
Northeast Utilities	No	The revisions made to Requirement R2 Part 2.1 appear to resolve the concern that past studies could not be used to comply with the short-term steady state study requirements. However, the language of Requirement R2 Part 2.2 still seems to suggest that current annual studies are always required for the long-term steady state assessment to be compliant. This may have been an oversight, for consistency Requirement R2 Part

Organization	Yes or No	Question 4 Comment
		2.2 should be modified to similarly read as Requirement R2, Part 2.1.
Hydro-Quebec TransEnergie	No	Requirement R2 Part 2.2 should be modified to read as 2.1 (not impose current annual studies as the only requirement for assessment)
American Transmission Company	No	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months.
Tri-State Generation & Transmission	No	2.1.5 - Change "shall be performed for" to "shall have been performed for."
Lakeland Electric	No	No, the phrase any material changes used in requirement R.2.6.2 will effectively cause all Planning Authorities to run all studies every year regardless of minor changes in the model. The overwhelming majority of PAs use a 10 year set of planning models developed annually by Regions or Subregions. These annual sets of planning models will always have some changes. The annual study requirement is especially problematic for Stability and Short circuit studies that require much more engineering time to complete and are much less likely to have results impacted by minor model changes such as different load forecasts. Uncertainty with audit review of technical rationale documentation will serve to focus Transmission Planning engineering resources on short term compliance to an extent that is counter productive. Please consider removing R.2.6.2
NBSO	No	NBSO agrees with the language for R2.1, but the language with R2.2 should be changed to be consistent with R2.1. NBSO disagrees with the revisions to R2.1.5. Requiring PAs to study instead of assess the possible unavailability of equipment with a lead time of a year or more will result in significant demand on resources with little impact on system reliability. NBSO also questions what additional value such studies will bring in addition to the N-1-1 requirements (P6).

Organization	Yes or No	Question 4 Comment
Central Maine Power Company New York State Electric & Gas Corp	No	We completely agree with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1) and R2.2 language should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study". Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).
Progress Energy	No	While PE does not disagree with the basic premise of 2.1, PE disagrees with the language to the extent that 2.1 is qualified by language in 2.6 and 2.6.2. The issue of managing modeling of case data is already adequately handled in MOD Standards. Furthermore, PE does not feel that the term “material” can be defined with any mutually agreed-upon boundaries, and could be construed to require any and all Transmission Planners and/or Planning Authorities to make multiple revisions of base cases each year. PE therefore appeals to the SDT to remove the language referring to R2 Part 2.6.2 and furthermore appeals for the deletion of R2.6.2. Furthermore, PE appeals to the SDT to modify R2.6.1 to say “For steady state, short circuit, or Stability analysis: the study shall be five calendar years old or less, unless a technical rationale can be provided to demonstrate the validity of the results of any studies older than five years or any studies using cases containing major modeling differences from other submitted studies.”
ERCOT ISO	No	Previous Comment unaddressed: Requirement 2.1.5: Including the spare equipment strategy will be difficult for a PC that doesn’t own or manage the transmission equipment or the strategies. This requirement should only be applicable to TP. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements.
New York Independent System Operator	No	NYISO completely agrees with the revision to R2.1, but this revision must be carried through to other sections (R2.2, 2.2.1). Revisions made to Requirement R2.1.5 have made it worse than as originally drafted. This would require the PC & TP to study, or in other words perform technical analysis of, the impact and probability of the possible unavailability of any piece of equipment with a lead time of one year or more. Such an evaluation of spare equipment strategies would require significant additional resources and data, but provide no benefit to system reliability, as it is redundant to the existing N-1-1 contingency requirement (P6).

Organization	Yes or No	Question 4 Comment
		R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list.
Xcel Energy	No	Specifically, the phrase "as follows" at the end of Part 2.1 does not appear to be an appropriate lead-in for the sub-parts under 2.1. Please consider re-wording Part 2.1 consistent with Part 2.4 to use the lead-in "The following studies are required:" Why is it essential to use the qualifier "annual" for "current studies" in Part 2.1? Can a study be considered current if it is conducted less frequently than once every year? Note that Parts 2.3, 2.4 and 2.5 do not use the "annual" qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both 2.1 and 2.2 to improve consistency. In Part 2.5, should "annually" be inserted after "shall be assessed" to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why. To improve semantics and consistency, please modify 2.2.1 as follows to make it consistent with 2.1.1 and 2.4.1 "System peak Load for one of the years in the…" We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording "… (steady state / stability) analysis shall be assessed annually…" can be interpreted to be much different than the semantics of the Part 2.3 wording "The short circuit analysis…. shall be conducted annually …". The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed –- is the usage of "conducted" instead of 'assessed" consistent with the intent? It is unclear why the stipulation to use "current or qualified past studies" needs to be repeated in each of the Parts 2.1, 2.2, 2.3, 2.4 and 2.5 when it is already specified in Requirement R2 at the highest hierarchy level. Suggest eliminating redundant usage by deleting from the parts under R2. In Part 2.6.2, the intent is awkwardly conveyed within the phrase "…the System represented in the study shall not include any material changes unless…". In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read "For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results." In Parts 2.6.1 and 2.6.2, the lead-in phrase "For steady state, short circuit or Stability analysis:" does not appear to be essential. Even in the absence of this phrase, wouldn't these two attributes of a qualified past study apply (by default) to all types of analysis? Suggest deleting this seemingly redundant phrase in both 2.6.1 and 2.6.2.

Organization	Yes or No	Question 4 Comment
		Perhaps this comment is more persuasive when considered together with the next comment. Recommend moving Part 2.6 to the first part under R2 (Part 2.1) because it defines the qualified past studies which are applicable to all types of analysis (steady state, stability and short circuit) that are detailed in the subsequent parts.
MRO's NERC Standards Review Subcommittee	Yes	R2.1.3 - We offer the minor suggestion of revising R2.1.3 to state, "Known outages of generation or Transmission Facilities with a duration of at least six months be simulated along with P1 events for the System peak or Off-Peak conditions when the outages are scheduled to occur." We interpret that the requirement should only call for the simulation of individual outages with duration of six months or more and not imply the simulation of sequential (back-to-back) outages where each individual outage is less than six months, but the composite duration of the back-to-back outages is more than six months. We also interpret that if two or more known outages with duration of at least six months are overlapping, then the overlapping outage condition would only be simulated for the conditions when the overlapping outages are scheduled to occur if the duration of the overlapping condition is at least six months. R2.1.5 - We offer a major suggestion regarding the phrase "could result in the unavailability of major transmission equipment" because this phrase is ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for defining unavailability of major transmission equipment" similar to R2.5.
NERC staff	Yes	NERC staff supports the use of qualified past studies for the Near Term horizon.
American Electric Power (AEP)	Yes	R2, Part 2.1 - idicates that 'qualified' past studies can be utilized. This is an ambiguous term and we suggest the SDT consider the implications.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	

Organization	Yes or No	Question 4 Comment
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 4 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
MidAmerican Energy	Yes	
Puget Sound Energy	Yes	

Organization	Yes or No	Question 4 Comment
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.2 Requirement R2, Parts 2.1.4 & 2.4.3 – sensitivity analysis:

Summary Consideration:

The SDT intent is that multiple condition sensitivities will be assessed since you are required to run the cases for peak and Off-peak conditions, multiple years, etc. If the problem exists in two or more of these cases, it would be an indication of 'multiple' problems. No change made.

The SDT understands that running sensitivities may require additional work for some entities. The sensitivities studied should be used to compare system response to different conditions to provide a broader perspective for the planner and the SDT believes that this is important enough to justify the additional work.

The SDT has made a clarifying change to the words in Requirement R2, part 2.1.4 based on comments received:

> **2.1.4** For each of the studies described in Requirement R2, Parts 2.1.1 and 2.1.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. To accomplish this, the sensitivity analysis in the Planning Assessment must vary one or more of the following conditions by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in System response~~performance~~:

The SDT has made the language in Requirement R2, part 2.7, bullet 7 consistent with the other parts of the standard as follows:

- List System deficiencies and the associated actions needed to achieve required System performance. Examples of ~~S~~such actions ~~may~~ include:

The majority of respondents agree with the changes to these requirements and only the changes to the requirements noted above have been made in response to stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 5 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions. If an entity does a case with a stressed set of assumptions, is it

Organization	Yes or No	Question 5 Comment
		necessary to do a non-stressed case? Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. If not, a suggested revision to Requirement 2.7.2 as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. In general, the scope of this requirement is too broad and non-specific, and only results in undue study burden. Is it necessary for sensitivity analysis to be included in requirements since in accordance with good engineering practices a conservative approach should be used in studies? The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in issue #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Hydro One Networks Inc.	No	The scope of this requirement is too broad and non-specific and only results in undue study burden.
MRO's NERC Standards Review Subcommittee	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of 'credible' and 'measurable change" because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC "shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance" similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #2 & # 5 - We suggest that the wording in bullet #2 be changed to "Expected transfers and other generation dispatch scenarios". This modification would put the transfer and dispatch element, which are complementary, together in the same bullet item, rather than grouping the 'generation dispatch' (operating level) element together with the generation capacity elements in bullet item #5. R2.1.4 bullet #7 - We offer the minor suggestion that the term "planned" be replaced with "known" to be consistent with R1.1.2 and R2.1.3. Besides the term "planned outage" has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity

Organization	Yes or No	Question 5 Comment
		studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. It's impractical to require corrective actions for longer term horizon sensitivities due to how fast the electric grid changes. We believe sensitivity analyses are valuable to improving the development of mitigation plans to address base case performance limit concerns. Some of the sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the interpretation of multiple sensitivity studies - more than one or a majority of the number that were studied?
IRC Standards Review Committee	No	The primary concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required by varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Alternatively, Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify the required sensitivity analysis. A measureable change in performance is unclear? Instead of a measurable change in performance, a measureable change in contingency response of the Bulk Electric System would be more appropriate. A change in performance implies not meeting one of the performance requirements as specified in Table 1.
Lakeland Electric	No	A "measureable change in performance" can be interpreted as not meeting one of the performance requirements as specified in Table 1 in order for the condition to be selected as a sensitivity. This will cause utilities to perform sensitivity analysis for all system conditions listed in R2.1.4 to determine which one fails to meet one of the performance requirements in Table 1, as one may not be able to tell performance impact until after the studies are performed. Suggested change: "...one of the following conditions by a sufficient amount...system conditions that may demonstrate a measurable change in system response."
Orlando Utilities Commission	No	What is meant by "measurable change in performance"? Is this a measure that the sensistivty should move the system from meeting the performance requirements to not meeting the performance requirements? Or just a measurable change in system response, IE the loading was 45% on this corridor but is now 76%.
US Bureau of Reclamation	No	Sensitivity analysis is not included in R2. This gets back to the structure of the standard. There should a clear indication of the studies that are to be included in the Near-Term and Long-Term portions of the Planning

Organization	Yes or No	Question 5 Comment
		Assessments.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
California ISO	No	Requirement 2.7.2 could be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. If a Planning Coordinator includes Corrective Action Plans to resolve performance deficiencies identified in multiple sensitivity analysis, the Planning Coordinator shall provide documentation to support those Plans.
ISO New England Inc.	No	Part 2.1.4, requires an entity to vary one or more conditions to demonstrate a change in performance. If the cases were initially stressed, this may force an entity to simulate conditions with less severe stresses. At this point, there is limited to no value to this additional workload. Having a requirement to test at least one sensitivity as a blanket requirement may not be informative by itself and is more unclear since sensitivities are being required on an undefined base set of conditions Additionally, our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies “only” if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2. Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
United Illuminating National Grid	No	If an entity does a stressed set of assumptions do they always need to do a non-stressed case?
Hydro-Quebec TransEnergie	No	It is questionable that sensitivity analysis be included in Requirements since a conservative approach should already be used in studies, in accordance with good engineering practices.
American Transmission Company	No	R2.1.4 & R2.4.3 - We offer a major suggestion regarding the terms of ‘credible’ and ‘measurable change” because these terms are ambiguous and not defined. So, there is a significant risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. We proposed adding that the TP and PC “shall provide documentation to support the technical rationale for determining the range of credible conditions and measurable change in performance” similar to R2.5. R2.1.4 & R2.4.3 bullet items - We offer the minor suggestion that the number and description of the bullet items in R2.1.4 match the bullet points in R2.4.3. Otherwise, please explain the reasons for any differences between

Organization	Yes or No	Question 5 Comment
		the bullet items in R2.1.4 and R2.4.3. R2.1.4 bullet #7 - We offer the minor suggestion that the term "planned" be replaced with "known" to be consistent with R1.1.2 and R2.1.3. Besides the term "planned outage" has a specific meaning in the Reliability Standards that are specific to the Operating horizon. R2.7.2 - With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", we do not think that mitigation plans should be required for deficiencies found in multiple sensitivity studies because the conditions in sensitivity studies are more extreme and less likely than base case conditions. Some sensitivity study conditions are not credible or plausible enough to warrant the implementation of mitigation measures. What is the SDT interpretation of multiple studies - more than one or a majority of the sensitivities that were studied?
Lakeland Electric	No	It is recommended that the phrase "...measureable change in performance..." be changed to "...measurable change in system response..." A change in performance is unclear, and could suggest that a sensitivity study is valid only if the System is stressed to the point that it no longer performs within the criteria established by Table 1. In addition, it is recommended that the following text appear after the last sentence of 2.4.3: "The condition or conditions to be varied shall be left to the discretion of the Transmission Planner or Planning Coordinator, provided they are selected from the list below."
Northeast Utilities	No	The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions as commented in Question #3. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
Modesto Irrigation District	No	This new requirement will expand the scope of the study work beyond a reasonable extent.
NBSO	No	Base case assumptions should be made such that they appropriately stress the system to be tested and are in accordance with good engineering practice. If the base cases are already stressed, the requirement to study sensitivity cases may result in the study of less severe conditions, and thus require additional time and resources while providing little additional value to the overall assessment.
Central Maine Power Company New York State Electric & Gas	No	These sensitivities need to be considered if not already included in the base case assumptions.

Organization	Yes or No	Question 5 Comment
Corp		
Progress Energy	No	PE does not have concerns in general with either 2.1.4 or 2.4.3. PE does, however, disagree with the wording at the end of the main paragraph of 2.4.3. Whether or not analysis qualifies as sensitivity analysis should not be predicated upon the end results; rather, it should be based upon major case modeling differences. PE therefore recommends that the phrase "...that demonstrate a measurable change in performance" be removed so that the last sentence in the main paragraph read "...by a sufficient amount to stress the System within a range of credible conditions."
ERCOT ISO	No	The stress test requirements should be deleted. The purpose of this proposed Standard is to establish planning performance standards that support reliable operation. This is achieved by imposing performance requirements relative to specific conditions and contingencies. Compliance with the performance metrics within these boundaries is presumably indicative of a reliable system. It is unclear what value is added by stress testing the system in accordance with undefined, vague parameters, as required by Requirements 2.1.4 and 2.4.3. The criteria in the relevant requirements that govern the stress testing are defined by the following ambiguous phrase: 1) "by a sufficient amount"; 2) "range of credible conditions"; and 3) "measurable change of performance". Application of these criteria introduces uncertainty for both the regulated community and the relevant compliance enforcement authorities, which, in turn, creates audit risks for regulated entities. Furthermore, there is no reliability value because the stress test requirements do not establish objective criteria and do not prescribe any actions based on the stress test results. Reliability Standards should set specific obligations that are readily discernible and achievable on a consistent basis. The existing Standard does this by setting specific performance obligations relative to specific conditions and contingencies. Conversely, the stress test requirements introduce ambiguity and uncertainty with no reliability benefit; the only apparent effect is unnecessary audit liability risk for regulated entities. Accordingly, ERCOT believes that these requirements should be deleted.
Tucson Electric Power Company	No	TEP agrees with removing the phrase "not already included in the studies." However, TEP does not understand the purpose of sensitivity studies. TEP is concerned that imposing additional sensitivity studies could lead to requirements that exceed the proposed standards. TEP recommends removing sesnitivity analysis from the standard.
New York Independent System Operator	No	Our concern involves wording under 2.1.4 and 2.4.3 that sensitivities are required varying one or more conditions. Subsequently, in requirement 2.7.2 corrective action plans need to be developed to resolve performance deficiencies "only" if identified in multiple conditions or require a rationalization why no corrective action plan is necessary. Multiple conditions sensitivities under 2.1.4 and 2.4.3 are necessary to satisfy requirement 2.7.2.

Organization	Yes or No	Question 5 Comment
		Requirement 2.7.2 adds ambiguity and should be removed. Requirement 2.7.2 should be revised as follows:2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis.
GDS Associates, Inc.	No	The requirements are extremely burdensome. We recommend changing the last sentence of 2.1.4 requirement by removing “by a sufficient amount to stress the System within a range of credible conditions that demonstrate a measurable change in performance:” because there are instances where listed conditions may not result in measurable changes in performance (Ex. An increase in load in a well built system may not cause any measurable changes in performance because there is sufficient transmission capacity to serve the load).
SMUD		What is the significance of changing the wording for section R2.1.5 from ‘assessed’ to ‘studied’ and ‘Planning Assessments’ to ‘studies’?
Western Area Power Administration	Yes	In Requirement 2.1.4, "Sensitivity Analysis”. How much change does it take in any of the modeling assumptions (load, generation, voltage support, topology, etc.) to significantly stress the system within a range of credible condition? As this Requirement relates to R2.7, Would it be necessary to have Corrective Action Plan(s) if needed to meet all the Sensitivity Cases? How many Sensitivities before must have Corrective Action Plan? Also - why is it essential to use the qualifier “annual” for “current studies” in Part 2.1? Can a study be considered current if it is conducted less frequently than once per year? Note that Parts 2.3, 2.4 and 2.5 do not use the “annual” qualifier, nor does Requirement R2. Recommend deleting this apparently non-essential qualifier in both R2.1 and R2.2. We are unable to appreciate why the wording in Part 2.3 is not consistent with that in Part 2.1, 2.2, 2.4 or 2.5. Note that the semantics of the wording “... (steady state / stability) analysis shall be assessed annually...” can be interpreted to be much different than the semantics of the Part 2.3 wording “The short circuit analysis.... shall be conducted annually ...”. The former requires the analysis to be *assessed* annually but 2.3 requires the analysis to be *conducted* annually without explicitly requiring it be assessed -- is the usage of “conducted” instead of ‘assessed” consistent with the intent? In Part 2.6.2, the intent is awkwardly conveyed within the phrase “...the System represented in the study shall not include any material changes unless...”. In the context of a *past* study, how can the System represented possibly include any material changes (that would have presumably occurred after the study)? Suggest modifying Part 2.6.2 to read “For steady state, short circuit or Stability analysis: no material changes have occurred in the System represented in the study or, if material changes have occurred, a technical rationale shall be provided to explain why they do not significantly impact the study results.”

Organization	Yes or No	Question 5 Comment
NERC staff	Yes	NERC staff supports removing the phrase “not already included in the studies” from the parts 2.1.4 and 2.4.3 of Requirement R2. We believe that the requirement is more clear and less subject to interpretation without this phrase.
MidAmerican Energy	Yes	R2.1.4 bullet #7 - Replace the adjective “planned” with “known” for consistency with R1.1.2 and R2.1.3.R2.3 Replace “conducted” with “assess” for consistency with R1.1.2 and R2.1.3.R2.4 Replace “current or past studies as qualified” with “current or qualified past studies as indicated” for consistency with R2
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
PNM	Yes	

Organization	Yes or No	Question 5 Comment
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
Ameren	Yes	
LCRA TSC	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation &	Yes	

Organization	Yes or No	Question 5 Comment
Transmission		
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Oncor Electric Delivery	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

3.3 Requirement R2, Part 2.4.1 – dynamic load models:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made in response to stakeholder comments.

The SDT does not intend that detailed dynamic Load models will be required for Loads in the System models used for the assessments. In particular, Requirement R2, part 2.4.1 states that an aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.

The SDT has placed this requirement in TPL standards because it is not presently covered in MOD standards.

Organization	Yes or No	Question 6 Comment
NERC staff	No	NERC staff understands why the SDT has inserted the word “expected” before “dynamic behavior of Loads,” but we have concerns with this addition. We understand that a PC or TP that models the best current industry understanding of load behavior should not need to worry about compliance if that model does not match actual load response for all possible system conditions. However, we are concerned that this change to part 2.4.1 of Requirement R2 may be too accommodating. If a PC or TP has unrealistic expectations about load behavior, would this permit the use of unrealistic models? While we have struggled to develop an alternative proposal, we hope that the SDT will identify a way to address this concern.
Northeast Power Coordinating Council	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard must be written that is specific to dynamic loads. Change belongs in a modeling standard, not in TPL-001.
Hydro One Networks Inc.	No	There is insufficient information and experience regarding dynamic load modeling. Hence, this should not be a requirement but a guide or an item to be considered to the extent possible. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of dynamic load model.
Transmission Issues Subcommittee	No	TIS believes that the term “expected” leaves the question as to “whose expectation.” It should be stated as to “expected...by the Transmission Planner.”

Organization	Yes or No	Question 6 Comment
Exelon Transmission Planning	No	There is not an industry consensus around best practices for modeling the dynamic behavior or characteristics of load. It is premature to make this a requirement in an enforceable standard which would be held to this degree of subjective auditing.
Manitoba Hydro	No	The last two sentences “System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads. An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable.” belong in the MOD standards. They are not required in TPL-001-2.
US Bureau of Reclamation	No	Not included in R2. See response to Question 3.2
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Ameren	No	Industry needs guidance regarding how to provide reasonable induction motor representation as opposed to generic models.
Hydro-Quebec TransEnergie	No	There is insufficient data available to accurately model system wide motor loads.
LCRA TSC	No	The first bullet item in Section 3.3.1 should be the same as the second bullet in Section 4.3.1. The wording is somewhat confusing in both. Also, the wording as proposed does not recognize that a high voltage limit could also be violated. Edits to the item as shown below are suggested. Tripping of generators where simulations show generation bus voltages or high side generation step up (GSU) voltages are outside known limits, or assumed to be outside generator steady state limits, or have reached the generator ride through voltage limit. Include in the assessment any assumptions made.
Tri-State Generation & Transmission	No	Rather than specifically call out induction motor loads, we recommend changing the second sentence to “Stability analysis shall include models that represent the expected dynamic behavior of system elements that could impact the study area.”
GTC	No	We have concerns for including induction motor representations in the load models without any study or bench-marking activities to meet the requirements of R2.4.1. This information should be supplied by the LSE as part of the MOD standard. We understand that the proposed standard will accept an aggregate system load model which represents the overall dynamic behavior of the load to relieve the burden of trying to develop specific induction motor load representation at each load bus. However this modeled system response will be considerably different compared to the actual system response which will open up the

Organization	Yes or No	Question 6 Comment
		industry to unwarranted scrutiny and possible compliance violation investigations.
Consolidated Edison Co. of New York, Inc.	No	There is insufficient information and experience regarding dynamic load modeling. It may also be included as a “sensitivity” analysis in 3.2, rather than requiring and expecting accurate representation of a dynamic load model. If this requirement is kept, a modeling standard should be written that is specific to dynamic loads. This change belongs in a modeling standard, not in TPL-001.
NBSO	No	By implication, the response of induction motor load would need to be considered when modeling the expected dynamic behaviour of loads that could impact the study area. NBSO suggests re-wording parts of R2.4.1 as follows: System peak load levels shall include a model which represents the expected dynamic behaviour of loads that could impact the study area. An aggregate system load model which represents the overall expected dynamic behaviour of load is acceptable.
Central Maine Power Company New York State Electric & Gas New York Independent System Operator	No	We have not determined a need to model dynamic loads, and therefore have not benchmarked any such models. We recommend that prior to this requirement being in place, a modeling standard should exist that is specific to dynamic loads.
ERCOT ISO	No	ERCOT ISO suggests adding “best available” as a descriptor to load models. Distribution Providers (DPs)/Load Serving Entities (LSEs) are the appropriate NERC functional entities to provide dynamic load data. Accordingly, Planning Coordinators (PCs) and Transmission Planners (TPs) must rely on those entities for that data. Despite reliance on DPs/LSEs for this data, the Standard proposes to impose an obligation on PCs and TPs to include a load model representative of “expected” dynamic behavior. Simply put, PCs and TPs do not have this information and should not be subject to compliance liability risk for an issue that is beyond their control. This change will still accomplish the goal of reflecting dynamic data in the relevant models, while mitigating PC/TP compliance risk by basing their compliance on information that is within their control - i.e. the “best available” information. Based on this change, the language should read - “System peak Load levels shall include best available Load models which represent the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads”. This language is also a more accurate reflection of the Consideration of Comments by the Standard Drafting Team after the March 2010 comment period.To address this issue in the most appropriate manner, the Standard should be revised to establish an appropriate process for collection, reporting and use of dynamic data based on assigning obligations to the appropriate functional entities. In essence, DPs/LSEs should be required to collect the data and report it to TPs. Because TP models are the basis for PC models, the dynamic data will be included in PC models as part of the process. However, DPs and TPs should still only be required to use the “best available” data. Continued use of this language will mitigate the liability risk associated with a

Organization	Yes or No	Question 6 Comment
		requirement related to data that is within the control of a third party. Even under a construct where DPs/LSEs are required to collect and report dynamic data, there is no guarantee they will do so and PCs/TPs should not be held accountable in those circumstances. Accordingly, PC/TP compliance risk will be mitigated by use of a “best available” standard.
GDS Associates, Inc.	No	We disagree with the content of this requirement based on several facts:- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concern about the effort required to ascertain the dynamic response of the load- The requirement references “Loads that could impact the study area” without specifying how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area.
MidAmerican Energy	No	MidAmerican questions if the widespread use of composite load models really provides significant benefits to additional dynamic analyses over generic load conversion assumptions which have been historically used. The use of composite load models may result in more precise individual load models, but no more accurate dynamic simulations. This poorly worded requirement should be deleted in its entirety as providing additional burden without any additional reliability benefits. If the composite load model requirement must be kept, it should be modified to include the following bolded text:”...System peak Load levels shall include a Load model which represents the expected dynamic behavior of Loads that could impact the study area, considering the behavior of induction motor Loads, but without requiring a detailed load survey be conducted...”
Platte River Power Authority	Yes	For consistency, use the qualifier “expected” in the second sentence of Part 2.4.1 also, such that it reads “...represents the overall expected dynamic behavior...”
Xcel Energy	Yes	For consistency, use the qualifier “expected” in the second sentence of Part 2.4.1 also, such that it reads “…represents the overall *expected* dynamic behavior…”
SERC Planning Standards Subcommittee	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	

Organization	Yes or No	Question 6 Comment
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	
Arizona Public Service Company	Yes	
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	
Western Area Power Administration	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Orlando Utilities Commission	Yes	

Organization	Yes or No	Question 6 Comment
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	

Organization	Yes or No	Question 6 Comment
Lakeland Electric	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Tucson Electric Power Company	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

3.4 Requirement R2, Part 2.5 – material clarification:

Summary Consideration:

The majority of respondents agree with the changes to these requirements and no changes to these requirements have been made based on stakeholder comments.

The SDT discussed defining ‘material change’ but did not believe that such a definition was appropriate in a continent-wide standard. With the wide variety in sizes and types of systems, the number of parameters that need to be considered, etc., there are too many variables involved. With the inclusion of Requirement R8 and the sharing of information, there is an opportunity for open discussion on such matters.

The SDT notes that Part 2.6.2 allows an entity to rely on a past study with a material change if “a technical rationale can be provided to demonstrate that System changes do not impact the performance results in the study area”. Therefore, it is up to the entities performing the study to provide the rationale based on changes, such as Load growth.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 7 Comment
Exelon Transmission Planning	No	The term ‘material changes’ is subjective. It is very difficult to determine a base case to study combinations of generator additions on a changing transmission network in the 6 to 10 year time period to be used for dynamic simulations. Dynamic studies should be performed whenever new generator interconnections are proposed and it is at that time where meaningful calculations can be performed. The long term six to ten year out dynamic studies for groupings of potential units should be done at a high level, if at all.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	This change does not clarify material. Material should be quantified somehow. We recommend changing the phrase “material generation additions or changes” to “generation in the vicinity with additions of changes larger than 200 MW”.
Lakeland Electric	No	Please consider removing R2.6.2. The “any material change” language can cause utilities perform studies due to material changes outside of and remote to its system.

Organization	Yes or No	Question 7 Comment
Orlando Utilities Commission	No	I agree with what I think is the intent. The word "Material" is meant to allow for changes in model to occur that are "small" relative to the TP/PC. For example the 400 MW generator that might be built in 10 years by another utility over a hundred miles, several dozen buses and generators away to not force new study work. However as written in 2.5 it requires you to define what a material change is, and could be applied to mean every change must be identified and explained rather then an overarching rationale that would only have you looking for changes that meet the material criteria. But then in 2.6.2 the word material is used with no obligation to explain what material is, only to explain if a material change would not impact the results in a study area. I recommend leaving the term material, but setting a requirement, measure, or definition that requires the TP/PC to define what they consider material specific to their system and circumstance. Since this will by the hetreogenous nature of the grid be different for each it may not be reasonable to pre-define what is reliable. Just as was done with many items in the ATC (MOD) standards, require that it be documented and questions on that rationale be answered. If a specific level of technical oversight is desired, consider requiring that description to be on file with the regional entity and approved by their planning committee. I think the team is heading in a good direction, it's just how the words will be applied that concern me. This may be a case where an Example or two would go a long way towards providing guidance to entities and auditors.
Manitoba Hydro	No	Adding the word “material” does not clarify Part 2.5. The word “material” can be interpreted in many ways and is subjective. In order to have a consistent approach by all TPs, the drafting team should add a definition of the term “material”. One TP may consider a new 200 MW unit as not being material because there are several larger units in the TPs system.
US Bureau of Reclamation	No	The term "material" is arbitrary. It is suggested that a specific value be used to trigger the assessment.
CenterPoint Energy	No	The SDT did not incorporate CenterPoint Energy's previous comments regarding R2; therefore, CenterPoint Energy's concerns remain.
Progress Energy	No	PE agrees in general with the changes made to R2.5. PE disagrees, however, with the language stipulating that current and past studies be qualified by the language in R2.6 Part 2.6.2 (see notes for Question 3.1 regarding recommending changes with regard to R2.6.2).
Tucson Electric Power Company	No	If a material change (generator addition/retirement, new generator models based on unit testing, or transmission line or non-distribution transformer addition) is not planned for the longer-term planning horizon, do the longer-term stability studies need to be performed? TEP's agreement/disagreement with Part 2.4.1 is

Organization	Yes or No	Question 7 Comment
		dependent on the response to this question. If the answer is the studies do not need to be performed, then TEP supports these changes.
GDS Associates, Inc.	No	We are not sure what will be included in these “material generation additions or changes”. Perhaps the standard should provide guidelines to determine what are these material changes or additions?
Xcel Energy	No	It appears that the requirement appended at the end of Part 2.5 “…and shall include documentation to support the technical rationale for determining material changes.” is duplicative of Part 2.6.2. Please address this apparent redundancy.
NERC staff	Yes	NERC staff supports inserting the word “material” in the reference to assessing the impact of proposed generation. We have some concern that this change leaves this part of the requirement open to interpretation, but we also understand the need to permit some degree of engineering judgment to be applied. It would not be appropriate to require that every potential generation addition be included in the assessment where some proposed additions may by inspection be deemed to be immaterial due to size and/or interconnection location.
IRC Standards Review Committee	Yes	However, the requirement infers that a subjective judgment from a compliance auditor will be required.
Bonneville Power Administration	Yes	It should be noted that if there is more generation proposed in an area than there load and export capability, all proposed material generation additions would not be represented. Determining what future generation additions to include in the Long-Term Transmission Planning Horizon may be based on a non-technical rationale rather than a technical rationale.
Western Area Power Administration	Yes	The drafting team could provide guidance on what is "material". In Part 2.5, should “annually” be inserted after “shall be assessed” to make it consistent with Parts 2.1, 2.2, 2.3 and 2.4? If the omission is intentional in 2.5, please explain why.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP to define what ‘material’ means in their ‘documentation to support the technical rationale for determining material changes.’ In Part 2.5 this rationale will decide whether or not any Long-Term Stability studies are required for the Planning Assessment. And in Part 2.6.2 this rationale will be a factor in qualifying a past study.
Independent Electricity System	Yes	We do not have a concern with this change but we don’t think it is necessary. It is not a requirement, and

Organization	Yes or No	Question 7 Comment
Operator		appropriate wording in the Measures can take care of it.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Southern Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
South Carolina and Gas	Yes	

Organization	Yes or No	Question 7 Comment
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
LCRA TSC	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	

Organization	Yes or No	Question 7 Comment
GTC	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
ERCOT ISO	Yes	
New York Independent System Operator	Yes	
MidAmerican Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

4. The SDT has revised the header notes based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT clarified the language of header note 'i' as a result of comments received as follows:

i. The response of voltage sensitive Load ~~including Load~~ that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements.

The majority of respondents agree with the changes to the header notes and no other changes to the header notes have been made based on stakeholder comments.

Requirements cannot be 'hidden' in the Table because the Table is specifically cited in the requirements text and is thus part of the requirements.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 8 Comment
Northeast Power Coordinating Council	No	Header note (i) in the first Table 1 (p. 10) could imply that voltage-varying load shall not be used to meet steady state performance requirements. Steady state load models in use include voltage-varying loads. The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in our case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected system and, potentially, to the implementation of unwarranted system upgrades. This note should be revised

Organization	Yes or No	Question 8 Comment
		to only reference loads which are disconnected due to voltage.
Transmission Issues Subcommittee	No	Delete the word "voltage" from the last header note J concerning Stability Only. All types of transient stability must be observed.
LCRA TSC	No	The third bullet of 4.3.1 requires the addition of relay models for stability studies. This type of analysis is performed today by scripting the tripping of multiple lines due to breaker failure events. The inclusion of relay models into the stability study will result in added complexity and an over reliance on relay models for system stability assessment. The stability assessment should assess stability resulting from the operation of relays as opposed to reliance on a relay model for proper system representations. Assurance of the proper operation of relays results from the analysis performed to set relays not from stability studies. From Section 4.3.1:"Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models." Section 4.5 requires that "The rationale for those Contingencies selected for evaluation shall be available as supporting information." This will have to be developed. Requirement R5 requires the establishment of criteria for transient voltage response of the system. This seems unnecessary given the proposed changes to Table 1. The proposed changes to table 1 seem to make clear the type of system response that is allowable through its specification of what is allowable in terms of interruptions to Firm Transmission and Non-Consequential loads. R5 states: "Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level."
Consolidated Edison Co. of New York, Inc.	No	o Header note (i) in the first Table 1 (p. 10) The explicit representation of (voltage-dependent) load models is perfectly consistent with the requirements defined in R1 (which calls for a comprehensive representation of system components and their expected operating status in the planning assessment period) and the impetus to the creation of more specific load models in dynamic assessments found Requirement 2.4 of this draft of TPL-001-2. It is a known that depressed voltage conditions cause certain system elements to perform below their rated capacity. For example, capacitors provide less voltage support and voltage controlling transformers are impeded by their finite tap range to direct VAR flow into areas affected by low voltage conditions. Certain load types, on the other hand, provide a self-compensating relief to depressed voltage by naturally decreasing demand in a manner proportional to their characteristics, without operator intervention. Choosing to negate the voltage-dependence of one of these system elements (load, in this case) results in an inaccurate system representation that, in turn, may lead to erroneous assessments of the reliability state of the interconnected

Organization	Yes or No	Question 8 Comment
		system and, potentially, to the implementation of unwarranted system upgrades.
Central Maine Power Company New York State Electric & Gas Corp New York Independent System Operator	No	Header note (i) in the first Table 1 could imply that voltage-varying load shall not be used to meet steady state performance requirements. NYISO steady state load models include voltage-varying loads. This note should be revised to only reference loads which are disconnected due to voltage.
MidAmerican Energy	No	The reference to BES should be placed back into Note a in the header above table 1.
Xcel Energy	No	Although we support the revised header notes, we believe that the following additional changes are needed to enhance clarity and improve consistency: We are unable to see the compelling need and/or the value of separating the header notes in three categories. Since the applicability of each header to either one or both steady-state and stability performance is obvious from its respective verbiage, we suggest eliminating the categorization. This will also allow the header notes to be reordered/regrouped as per related functionality, thus improving the Table 1 readability. Following is a suggested re-ordering of header notes: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected

Organization	Yes or No	Question 8 Comment
		to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
MRO's NERC Standards Review Subcommittee American Transmission Company	Yes	We offer the major suggestion that Requirements not be created in the Performance Table and be absent from the Requirement section. Requirements should only be referred to in the Performance Table after they already exist in the Requirement section. a. Notes “f” and “g” under “Steady State Only” section in the Table 1 header create requirements (e.g. use the verb, “shall”) that do not appear in the Requirements section. We suggest adding R3.3.5, which could read, “Applicable System Operating Limits for the planning horizon shall not be exceeded.” [After R3.3.5 is added, Notes “f” and “g” should be revised and refer to R3.3.5.]. b. Note “i” under “Steady State Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R3.3.6, which could read, “The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state voltage requirements.” [After R3.3.6 is added, Note “d” should be revised to refer to R3.3.6. c. Note “j” under the “Stability Only” section in the Table 1 header creates a requirement (e.g. use the verb, “shall”) that does not appear in the Requirements section. We suggest adding R4.1.4, which could read, “Transient voltage response shall be within acceptable limits established by the Planning Coordinator and the Transmission Planner”. [After R4.1.4 is added, Note “j” should be revised to refer to R4.1.4.]
Western Area Power Administration	Yes	Following is a suggested re-ordering of header notes to replace of the three categories concept - same information: a. Applicable Facility Ratings shall not be exceeded. The System shall remain stable. Cascading and uncontrolled islanding shall not occur. b. Planning event P0 is applicable to steady state only. c. Consequential Load Loss as well as generation loss is acceptable as a consequence of any event except P0. d. The response of voltage sensitive Load including Load that is disconnected from the System by end-user equipment as a consequence of any event shall not be used to meet steady state performance requirements. e. System steady state voltages and post-Contingency voltage deviations shall be within acceptable limits established by the Planning Coordinator and Transmission Planner. f. Transient voltage response shall be within acceptable limits as established by the Planning Coordinator and Transmission Planner. g. Planned System adjustments such as Transmission configuration changes and re-dispatch of generation are allowed if such adjustments are executable within the time duration applicable to the Facility Ratings. h. Simulate the removal of all elements that Protection Systems and other controls are expected to automatically disconnect for each event. Simulate Normal Clearing unless otherwise specified.
NERC staff	Yes	NERC staff supports the changes to the header notes in Table 1.

Organization	Yes or No	Question 8 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	Yes	We support the changes to the performance tables.
Platte River Power Authority	Yes	I like the flexibility you give the PC and TP in Requirements R3 and R4 to develop their rationale for the Contingencies they select for evaluation.
Orlando Utilities Commission	Yes	I am assuming you mean the header notes on the performance table
Progress Energy	Yes	PE assumes the term “header notes” is referring to the “Planning Performance Events” at the top of Table 1. If this is the case, PE has no concerns with the present language.
SERC Planning Standards Subcommittee	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Bonneville Power Administration	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Electricity Coordinating Council	Yes	

Organization	Yes or No	Question 8 Comment
Arizona Public Service Company	Yes	
PacifiCorp	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
Lakeland Electric	Yes	
PNM	Yes	
FirstEnergy	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
CenterPoint Energy	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
SRP	Yes	
California ISO	Yes	
Seattle City Light	Yes	

Organization	Yes or No	Question 8 Comment
California Energy Commission	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
United Illuminating	Yes	
Ameren	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
Lakeland Electric	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Modesto Irrigation District	Yes	
NBSO	Yes	

Organization	Yes or No	Question 8 Comment
Oncor Electric Delivery	Yes	
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
GDS Associates, Inc.	Yes	
Puget Sound Energy	Yes	
Sacramento Municipal Utility District	Yes	
Southern California Edison Company	Yes	

5.

The SDT has revised the performance table (including the list of extreme events and footnotes) based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following clarifying changes to address concerns raised in the comments:

- P0 – delete superscript 9 in column 6: No[9]
- P5 event description: Delayed Fault -Clearing —due to the failure of a non-redundant relay[13] protecting the Faulted element to operate as designed, for one of the following:
- Extreme events language for Stability events has been made consistent with P5.
- Added 'Breaker' to the Bus-tie and non-Bus-tie phrases in P2 and P4

No other changes were made to the Performance Table based on stakeholder comments.

The SDT fully realizes that Project 2010-11 must reach resolution prior to finalizing TPL-001-2 and stated same in the information attached with the fifth posting of Project 2006-02.

The SDT has made the language in Requirement R2, part 2.8.2 consistent with that in Requirement R2, part 2.7.4:

2.8.2 Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 9 Comment
NERC staff		NERC staff is concerned with P5 and footnote 9 and thus cannot support these changes in their entirety. First, a revision to the Draft 4 definition of P5 should be used in lieu of the current Draft 5 version: "Loss of multiple elements caused by the Fault clearing consistent with failure of a single Protection System while clearing a fault on one of the following: . . ."After reviewing the P5 contingency throughout various drafts of this standard, along with existing Table 1 for TPL-001 through TPL-004, NERC staff's primary concern is that this most recent version is going in the wrong direction by becoming too limiting regarding which Protection System component failures are covered. Draft 5 is an improvement because it removes the reference to loss of

Organization	Yes or No	Question 9 Comment
		multiple elements in Draft 4 (which defined P5 as "Loss of multiple elements caused by the failure of a single Protection System while clearing a fault on one of the following: . . ."). Draft 5 takes a step backward, however, by referring to Delayed Fault Clearing. The advantage of not referring to Delayed Fault Clearing is that for cases where redundant protection systems are provided, the fault clearing may not be delayed even when a single Protection System failure occurs. Ideally, NERC staff believes that P5 should refer to "failure of any component of a Protection System," but NERC staff recognizes that we cannot get there until the term Protection System is redefined and Project 2009-07-Reliability of Protection Systems is underway. Until that change is possible, NERC staff encourages the SDT to use the revised version of P5 proposed above. A second concern is with footnote 9, which is used numerous times in Table 1. System adjustments may be used in two different settings: the first is to address the aftermath of a particular Contingency; the second is to prepare for the next Contingency.Staff suggests that the current footnote 9 have this language added: "Post-Contingency Ccurtailment of Firm Transmission Service to address the simulated contingency, when coupled with ...." Footnote 9 is used in the column labeled "Interruption of Firm Transmission Service Allowed" whenever a "No" is provided. The footnote 9 in this column has to do with System adjustments that address the aftermath of the Contingency that is being simulated. Therefore, no footnote 9 appears appropriate for category P0 (No Contingency). The reference in footnote 9 to no load loss and staying within applicable Facility rating, including those on a neighboring system, is sufficient for addressing the aftermath of the Contingency being simulated. To address next Contingency, an additional footnote is needed in the "Initial System Condition" column for category P3 and category P6. The following is suggested: "System adjustments to prepare for the next Contingency must be completed within 30 minutes." Footnote 9 is used in the column labeled "Initial System Condition" for category P3 and category P6, and these two categories define the loss of an Element "followed by System adjustments" and then followed by the loss of a second Element. It is unclear whether the intent in footnote 9 in these two cases is meant to address the same issue referenced above (i.e. the aftermath of the Contingency being simulated) or whether it is intended to address the next Contingency. Thus, both situations need to be addressed using the suggestions indicated above.
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.		To support the change to P5, other items need to also be modified. In Table 1 - Steady State & Stability Performance Extreme Events (p. 12), in the Stability Section, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words "relay failure". This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing.

Organization	Yes or No	Question 9 Comment
		Note 11 (p. 14) needs clarification as shown: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less. There are two tables labeled "Table 1". Suggest that the extreme events table be renamed "Table 2".
MRO's NERC Standards Review Subcommittee		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be "higher" in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly "lower" in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding "1. Generator" to the listing in the Initial System Condition (Loss of . . .) column. Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: "a. Loss of three or more circuits that share a common structure." Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: "6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters."
Bonneville Power Administration		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore the proposed footnote 12 should include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, planned or controlled interruption of electric supply to radial

Organization	Yes or No	Question 9 Comment
		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.”
Exelon Transmission Planning		Comments: The term ‘HV’ in the performance table should be defined as ‘Bulk Electric System elements up to 300 kV, not simply all elements ‘below 300 kV’. Footnote 12 should be clarified to specifically state the requirements before voting takes place. The performance criteria should be based on the voltage level of the element experiencing stress due to the contingency, not based on the voltage level of the outaged element. It does not seem to make sense that the loss of a 500 kV bus would not allow for any non-consequential load shedding unless the bus contained a 500 to 230 kV transformer, in which case additional load shedding would be allowed. If outages on a 230 kV system, such as bus fault with stuck breaker, were to cause overloads on a 500 kV network it is acceptable to shed load, but if the outages were on the 500 kV system originally it would not be acceptable to shed additional load. It seems as if it should be the severity of the situation and the elements involved that would dictate allowable remedial actions and not the initial cause of the disturbance. If, for example, there was a 500 kV contingency outage that caused problems on the 230 kV system there would be a problem that may require load shedding on the 230 kV system. If there were a 230 kV contingency or series of contingencies that caused overloads on the 500 kV system, it would be more difficult to find enough lower voltage load to shed to bring the 500 kV system back to applicable ratings or conditions. The inability to shed non-consequential load could theoretically be resolved by hanging a small EHV / HV transformer on a particular bus, or by tapping a EHV line with an auto transformer.
Southern Company		NO. We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Western Electricity Coordinating Council Arizona Public Service Company PNM SRP California Energy Commission Los Angeles Department of		Table 1, P5 currently requires the study of “[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed”. As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: “Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following”. In Table 1, P2 and P3, the last column “Non-Consequential Load Loss Allowed” where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential

Organization	Yes or No	Question 9 Comment
Water and Power Pacific Gas and Electric Company Modesto Irrigation District Puget Sound Energy Sacramento Municipal Utility District		Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote “b”. This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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.” Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
E.ON U.S.		E.ON U.S. believes that Table 1 should be formatted to avoid having the tables split by page breakers. In addition, tables spanning across multiple pages should have headers at the top of each page.
Florida Reliability Coordinating Council, Inc - Transmission Working Group		Footnote 12 performance requirements of Table 1 should allow the loss of non-consequential load for all contingency categories except for P0. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. Footnote 9 should also be under consideration as part of Project 2010-11 and should be noted as such for clarification.
Western Area Power Administration		In footnotes 9 and 12, two critical issues are being addressed in large part via these "clarifying" footnotes. These are curtailment of "Firm Transmission Service" (which seems primarily to be a contract/scheduling issue) and the loss of "Non-Consequential Load." Perhaps these issues should receive more attention in the

Organization	Yes or No	Question 9 Comment
		actual requirements. In P5 the term "Protection System" was removed and replaced with "relay". How are protection system elements other than relays accounted for? In studying a multiple contingency event with a communication system or control circuitry failure would it be necessary demonstrate P1 performance levels? These details could become critical as industry deals with issues such as FERC's interpretation of TPL-002-0 Requirement R1.3.10 (RM10-6-000). In Table 1 - Extreme Events - Stability - Items 2a-2d, change "Protection System failure" to "relay failure" to be consistent with changes in P5. Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". Footnote 13 - Delete "voltage (#27, #59)" since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of "Loss of multiple elements". Suggested Event P4 description is: "Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:" In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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

Organization	Yes or No	Question 9 Comment
		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." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).
PacifiCorp		Under Category P2 (Single Contingency) and Normal System Conditions, the performance table indicates that, for both HV and EHV, interruption of firm transmission service and non-consequential load loss are not allowed following the opening of a line section without a fault. This section of the performance table should distinguish between EHV and HV - performance requirements following the opening of a line section without a fault should be the same as those for a bus section fault. As with the bus section fault, interruption of firm transmission service and non-consequential load loss should be allowed for HV.
NorthWestern Energy (NWMT) Idaho Power Co		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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."

Organization	Yes or No	Question 9 Comment
Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss. It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
FirstEnergy		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay (footnote 13) protecting the Faulted element to operate as designed". To the extent fully redundant relaying exists with no expected delay in Fault Clearing its understood that the P5 event would not be a concern for the redundant system design. The drafting team has taken appropriate steps within the TPL standard to focus on relaying failures to provide clarity in what is required for P5 planning event.
Platte River Power Authority		No. Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note:

Organization	Yes or No	Question 9 Comment
		Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). In Table 1 - Planning Events - Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term 'Bus-tie Breaker' or 'non-Bus-tie Breaker' as applicable. In Table 1 - Extreme Events - Stability - Items 2a-2d, do you mean 'Protection System failure' here, or do you want to change to 'relay failure' to be consistent with changes in P5?
Orlando Utilities Commission		I generally agree with the direction the team has gone. Footnote 9 should also be highlighted as being part of the project 2010-11 discussion just as footnote 12 is.
Manitoba Hydro		In point g, violations are noted in terms of post-Contingency voltage deviations rather than post-Contingency voltage limits. This may lead to confusion, as some utilities evaluate performance based on a post-Contingency voltage deviation criterion while other utilities evaluate performance based on post-Contingency voltage limits. This same comment applies to Requirement R5.Suggested rewording for point g:System steady state voltages and post-Contingency voltages or voltage deviations shall be within acceptable limits as established by the Planning Coordinator and the Transmission Planner. Suggested rewording for the first sentence in Requirement R5:Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltages or voltage deviations, and the transient voltage response for its System. Note 12 states that an outstanding issue related to non-consequential load loss is being discussed. This will create a lot of uncertainty. Manitoba Hydro could not support this standard unless the resolution of Note B is known.
CenterPoint Energy		CenterPoint Energy appreciates the effort put forth by the SDT in revising the performance table. The current draft of P5 is preferable to previous versions.
TVA Transmission Planning & Compliance		TVA is concerned about footnote 12 (known as footnote b in existing TPL standards). TVA believes that utilities should be given some freedom in dropping local load in response to N-1 events as long as overall

Organization	Yes or No	Question 9 Comment
		BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. TVA does agree with the revisions made specifically to the P5 event. TVA wishes to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
SMUD		For the Western Interconnection, the performance level for a Bus-tie breaker fault under TPL-001-2, Table 1, Item P2-4, Notes (a) and (f), requires no thermal overloads and no cascading. While, FAC-010-2.1, R1.2, R2.5-R2.6, as modified by E1.1, E1.1.7, E1.3, and E1.3.1 requires a different performance level of no cascading. Please explain why this regional variance is not included under TPL-001-2, Item E.
California ISO		We support these changes, although we suggest that the proposed footnote 12 include an interim provision to default to the existing footnote “b” in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, “Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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.”
Seattle City Light		Table 1, P5 does not recognize the existence of redundant (or backup) relays. These are an integral part of the protection system design and should be considered in analysis of SLG faults. The TPL standard should encourage redundant, fail-safe systems, not ignore them. In Table 1, P2 and P3, we have a concern about not allowing non-consequential load loss. Project 2010-11 is deciding on this issue, but is not completed (see footnote 12). Should the standard become effective before this project is completed, no non-consequential load loss would be allowed, requiring many transmission additions and reconfigurations. Please change the "NO" in the last column to "YES" until the completion of Project 2010-11.
ISO New England Inc.		We are supportive of the change to P5. However, in making this modification, other items need to also be changed. In Table 1 - Stability, the language should be made similar to wording in P5. Protection System should be removed and replaced with the words “relay failure”. This change should be made for 2a through 2d:2. Local or wide area events affecting the Transmission System such as: a. 3Ã˜ fault on generator with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. b. 3Ã˜ fault on Transmission circuit with

Organization	Yes or No	Question 9 Comment
		stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. c. 3Ã˜ fault on transformer with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. d. 3Ã˜ fault on bus section with stuck breaker10 or a relay failure resulting in Delayed Fault Clearing. We also believe that Note 11 needs clarifying wording as shown below:"Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for a total of 1 mile or less"
United Illuminating National Grid Central Maine Power Company New York State Electric & Gas Corp		In Table 1 - Stability, Make language similar to wording in P5. "Protection System" should be removed and replaced with the words "relay failure". This would avoid future interpretation issues about the intent of this requirement (as we understand it) to exclude more severe though less likely failures such as battery systems. This change should be made for 2a through 2d on page 12).In Note 11 (page 14) ADD the wording shown in "quotes" below: Excludes circuits that share a common structure (Planning event P7, Extreme event steady state 2a) or common Right-of-Way (Extreme event, steady state 2b) for "a total of" 1 mile or less.
Hydro-Quebec TransEnergie		In table 1 on page 12 (Stability section), Relay failure should replace Protection System
LCRA TSC		An important footnote to Table 1 is omitted from this proposed revision. This omission prevents adequate evaluation of the footnote. Footnote 12 in Table 1 is no longer applied to P2.1, P2.2, P2.3, P4, and P5. The footnote states: “Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here.” The footnote should be removed from the proposed revision until Project 2010-11 is concluded.
American Transmission Company		We offer the major suggestion that the P3 Category performance criteria be modified to apply only to the loss of two generators. The SDT properly recognizes that generator outages are significantly more probable than line or transformer outages and should be “higher” in the category list. However given the clearly higher probability of generator outages, the probability of the loss of two generators is clearly higher than the loss of a generator and line or the loss of a generator and transformer. Therefore, if the loss of two generators is in the P3 category, then the loss of a generator and line or transformer should be clearly “lower” in the category list. We suggest the listing of: the loss of a generator and some other element (e.g. transmission circuit, transformer, shunt device, and single pole of DC line) be moved to a lower event category, such as the P6 Category by adding “1. Generator” to the listing in the Initial System Condition (Loss of . . .) column. We offer the minor suggestion that Item 2.a in the Extreme Events, Steady State section - Clarify the meaning of the loss of multiple circuits in Item 2.a by using wording similar to P7. We suggest this text: “a. Loss of three or more circuits that share a common structure.”

Organization	Yes or No	Question 9 Comment
		We offer the minor suggestion that Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: “6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters.” ATC has significant concerns with Q3.2 (R2.1.4 & R2.4.3), Q4 (Table requirements) and Q5 (P3 scope), as noted above. In addition, ATC offers the following suggestions to promote proper Reliability Standard quality and content. (1.) Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: “Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard.” 2.) R2.1.5 - We propose replacing the term ‘major Transmission’ with “BES” because BES is a well defined term, while the term ‘major Transmission’ is not. (3.) Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 4.) R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, “. . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures.” to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year’s Corrective Action Plans. (5.) R3.3.1 - The term of ‘controls’ is ambiguous and not defined, unlike the term, ‘Protection Systems’, which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. (6.) R3.3., bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1, bullet #1 must be different from its counterpart, R4.3.1, then please explain the reasons for any differences.

Organization	Yes or No	Question 9 Comment
		(7.) R3.4.1 - Compliance with the requirement "to coordinate" is problematic and non-measurable. We suggest replacing it with the requirement "to communicate". 8.) R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? (9.) R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, "No generating unit connected to the BES shall pull out of synchronism." For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. (10.) R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. (11.) R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. (12.) R5 - We propose removing the criteria item, "post-Contingency voltage deviation", because this criterion has not been developed and used widely enough in the industry to be introduced into the standards. (13.) R7 - Revise part of the requirement text to read, ". . . identify each entity's individual and joint responsibilities . . ." to provide better clarity. Perhaps this requirement should be listed at the beginning of the Requirements section, instead being mentioned near the end of this section. (14.) Change the forward referencing to backward referencing. We agree with R2.6, R3.1, R3.5, R4.1, and 4.2. However, we suggest that the requirements be ordered so that all of the references refer back to earlier text, rather later text to be consistent with the rest of this standard and other referencing in this standard (e.g. R2.1.3, R2.1.4, R2.4.3, R3, R3.3, R3.5, R4, R4.3, R4.4, R4.5), as well as other standards.
Tri-State Generation & Transmission		Table 1, P5 does not seem to account for redundant relays in the Protection System to mitigate potential relay failure. We recommend changing the "Event" to "Delayed Fault Clearing due to the failure of a relay to operate as designed, if that is the only relay protecting the Faulted element, for one of the following:" In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement

Organization	Yes or No	Question 9 Comment
		"No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue). Second, we are unclear why voltage relays are included in footnote 13 and think they can be removed. Third, in the Extreme Events - Stability section of Table 1, items 2a-2d "Protection System failure" should be changed to "relay failure" to be consistent with Table 1, Category P5.
Lakeland Electric		The performance requirements of Table 1 do not allow the loss of non-consequential load for single and multiple contingency events. The disallowance of load loss does not provide any real benefit to the reliability of the BES and is an unnecessary overreach into local quality of service issues that are best addressed by State, Provincial or Municipal authorities. There may be circumstances such as high local transmission costs or local opposition to transmission construction where prohibition of non-consequential load loss represents a poor cost/benefit or quality of life tradeoff. Having a provision at the regional level that a PA or TP can have a certain amount of non-consequential load loss designed or planned in to its system that would be reasonable if it is acceptable to the RE and does not have an adverse impact on the remaining BES. In lieu of such a RE provision, providing a quantitative cap in non-consequential load loss such as 100 MW may be rationale compromise in the goal of limiting load loss for the more probable outage events. Our preference would be to retain the capability of limited non-consequential load loss.It is our understanding that footnote 9 is under consideration as part of Project 2010-11 and should be noted as such for clarification.
NBSO		For consistency, 'Protection System' should be replaced with 'relay' on Table 1 (p12) Stability Section, items

Organization	Yes or No	Question 9 Comment
		2a-2d.
Progress Energy		PE remains concerned with the present draft of TPL-001-2 regarding the presence or absence of footnotes in particular events. PE believes that, for all events in Table 1 except P0, any "No" designation in the "Non-Consequential Load Loss allowed" column should have Footnote 12 appended to it. Several events do append footnote 12 to a "No" answer, but several do not. PE does not see why certain events should be denied the use of Footnote 12 as long as Footnote 12 is worded in a manner such that the BES will not be adversely affected.PE has additional concerns regarding two Footnotes. Footnote 9 contains language regarding firm transmission service that is very similar to language presently under review in NERC Project 2010-11. PE feels that Footnote 9 should have had a statement at the end similar to that of Footnote 12, such as "Note: Firm Transmission Service is being decided in Project 2010-11. When that project is finalized, the resolution will be copied into Footnote 9." Without such a statement, PE cannot understand why the Firm Transmission language in footnote (b) under Project 2010-11 is being reviewed, while it is apparently no longer being reviewed in Project 2006-02.Footnote 12 contains the following language as a place holder: "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here." PE has filed substantial comments on the footnote (b) issue in previous drafts, pointing out that disallowance of curtailment of non-consequential load is a local load issue and not a BES concern. PE therefore cannot make any positive determination as to whether the draft Standard, TPL-001-2, and its associated Table 1, will be a viable Standard until the language in Footnote 12 is resolved via Project 2010-11. Given the potential for unresolved and confusing issues regarding the parallel development of Project 2006-02 and 2010-11, PE encourages NERC to resolve all issues within Project 2010-11 before taking the draft Standard TPL-001-2 to ballot in Project 2006-02.
Tucson Electric Power Company		Table 1, P5 currently requires the study of "[d]elayed Fault Clearing due to the failure of a relay13 protecting the Faulted element to operate as designed". As written, this requirement does not recognize the use of redundant relays for primary protection. In some cases side by side relays are used to provide primary fault tripping if one relay fails to operate. Per the requirement as stated, the redundant relay would provide no value in meeting this requirement. Please revise to acknowledge backup relays: "Single failure of a protection relay13 protecting the Faulted element to operate as designed, resulting in backup relay actions or Delayed Fault Clearing, for one of the following". In Table 1, P2 and P3, the last column "Non-Consequential Load Loss Allowed" where the requirement "No12" appears, and in footnote 12, the standard as proposed does not allow for any Non-Consequential Load Loss. When the Non-Consequential Load Loss (footnote b) issue is clarified in Project 2010-11 this requirement may be changed. Therefore, if this proposed Standard is enforced before Project 2010-11 is completed, entities will be required to meet this No Non-Consequential Load Loss requirement without the exception allowed in the existing TPL-002-0, footnote "b". This will require immediate redesigns to meet this

Organization	Yes or No	Question 9 Comment
		particular requirement. The unintended consequence could be that operators of local systems that are currently networked may opt to begin operation as radial systems, and future designs for local systems may be radial, at any voltage level. We suggest that the proposed footnote 12 include a provision to default to the existing footnote "b" in TPL-002-0 until Project 2010-11 is decided. Please revise footnote 12 to read, "Note: Non-Consequential Load Loss is being decided in Project 2010-11. When that project is finalized, the resolution will be copied here. In the interim, 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." Timing of this project and project 2010-11 is critical. It would be very difficult to vote to approve the proposed TPL-001-2 prior to knowing the outcome of Project 2010-11 (footnote b issue).Non-Consequential Load Loss and curtailment of Firm Transmission Service should be allowed for loss of EHV BES elements for Category P4 and P5 events.
New York Independent System Operator		There are two tables labeled "Table 1". The extreme events table should be renamed "Table 2".
MidAmerican Energy		Voting "no" - Footnote 6 - Further clarify the applicable shunt devices in Footnote 6 with this suggested text: 6. Requirements which are applicable to shunt devices, also apply to FACTS devices that are connected to ground, but not instrument voltage transformers or surge arresters
Southern California Edison Company		SCE supports the revised performance table.
Omaha Public Power District		Why is Footnote 12 used for some occurrences of the word "No" in the last column of Table 1 but not other occurrences of the word "No"?
Hydro One Networks Inc.		No selection boxes in this question. Yes, we support.
SERC Dynamics Review Subcommittee		Yes. The SERC DRS supports the revisions.
Duke Energy		We support the changes.

Organization	Yes or No	Question 9 Comment
South Carolina and Gas		Yes
Xcel Energy		The defined term "Bus-tie Breaker" is not used per se anywhere in the Requirements or in Table 1. Suggest changing the description for Events P2-3, P2-4, P4 and P4-6 to use the term Bus-tie Breaker or non-Bus-tie Breaker, as applicable. Existing P5 event description needs improvement since the phrase "…failure of relay protecting the Faulted element to operate as designed…" reads awkwardly and also includes some superfluous verbiage that can be omitted. For example, isn't "protecting the faulted element" the basic function of every protective relay? Also, isn't "(failure) to operate as designed" inherent in the definition of Delayed Fault Clearing? Suggested P5 event description is: "Delayed Fault Clearing due to the operation failure of a primary protection relay[13] when attempting to clear a fault on one of the following:" Footnote 13 – Delete "voltage (#27, #59)" since the under/over voltage relays are not called upon to provide the primary protection for fault clearing on Transmission elements. In Table 1 – Extreme Events – Stability – Items 2a-2d, change "Protection System failure" to "relay failure" to be consistent with changes in P5. Suggest modifying Event P4 description to be more consistent with Event P5 description by including Delayed Fault Clearing in the description in lieu of "Loss of multiple elements". Suggested Event P4 description is: "Delayed Fault Clearing caused by a stuck non Bus-tie Breaker attempting to clear a fault on one of the following:"

6. The SDT has revised the Measures based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT has made the following changes due to industry comments:

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

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

M8. Each Planning Coordinator and Transmission Planner shall provide evidence, such as email notices, documentation of updated web pages, postal receipts showing recipient and date; or a demonstration of a public posting, that it has distributed its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any functional entity who has indicated a reliability need and that the ~~functional entity~~ Planning Coordinator or Transmission Planner has provided a documented response to comments received on Planning Assessment results within 90 calendar days of receipt of those comments in accordance with Requirement R8.

Data retention for R7 - The current, in force documentation for the agreement(s) on roles and responsibilities, as well as ~~all such~~ documentation for the agreements in force since the last compliance audit, in accordance with Requirement R7 and Measure M7.

Conforming changes were made to M6 and the data retention for R6/M6. Conforming changes were made to R1 to eliminate the phrase, “the latest.” The majority of respondents agree with the changes to the Measures and no other changes to the Measures have been made based on stakeholder comments.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 10 Comment

Organization	Yes or No	Question 10 Comment
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	It appears that there is a disagreement between R8 and M8, regarding public posting. We Agree with M8 posting option.
NorthWestern Energy (NWMT)	No	Measure M6 is too vague. It is unclear how to identify the conditions of Cascading, voltage instability, or uncontrolled islanding. The Glossary of Terms defines Cascading as "The uncontrolled successive loss of system elements triggered by an incident at any location. Cascading results in widespread electric service interruption that cannot be restrained from sequentially spreading beyond an area predetermined by studies." Does the loss of system elements have to extend beyond the Control Area to be considered "Cascading"? Is there a Megawatt threshold that must be satisfied? Is there a time duration involved? Also, "cascading outages" needs to be defined. In addition, "voltage instability" and "uncontrolled islanding" should both be defined.
Lakeland Electric	No	please consider remove "the latest" from M1
Ameren	No	For measurements M3 and M4, there is some question as to what is to be provided as evidence of a study. Would the study results alone provide sufficient evidence, or does the entire powerflow, stability, or short circuit effort need to be documented in a formal study report? There are no measures for the creation and coordination of contingency lists that are to be developed in R3.4, R3.5, R4.4, and R4.5. Are these contingency lists required to be a documented part of the study?
MidAmerican Energy	No	Revise measures to be consistent with requirements. 1. R6 Delete "any". The use of the word any in standards should not be allowed. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: "Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard." 3. R2.1.5 - We propose replacing the term 'major Transmission' with "BES" because BES is a well defined term, while the term, 'major Transmission', is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, "Perform an analysis for at least one year in the Near Term Transmission Planning Horizon." This requirement would set an expectation

Organization	Yes or No	Question 10 Comment
		that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.2 - Delete 2.7.2. With regard to "include actions to resolve performance deficiencies identified in multiple sensitivity studies", mitigation plans should not be required for deficiencies found in multiple sensitivity studies because the conditions in some sensitivity studies are more extreme and less likely than base case conditions. Some of the sensitivity study conditions are not credible. 6. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. 7. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 8. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit with a Point of Interconnection connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 9. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 10. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 11. R.4.3.2 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator transient voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R4.3.2 must be different from its counterpart, R3.3.2, then please explain the reasons for any differences. 12. R5 - This requirement should allow the applicable entity (such as the TOP / TO) to define a “Post-Contingency Voltage Deviation” as this criteria is not used widely enough in the industry to be a well

Organization	Yes or No	Question 10 Comment
		established criteria. 13. Revise R8 to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity...” 14. Data Retention for R3, R5, R6, & R7 - The MRO NSRS proposes that the wording in these elements be revised to change “All” to “The”. The word “All” is unnecessary and could encourage over-the-top compliance monitoring and enforcement. The revised data retention would read as follows: “The studies performed in support....”
NERC staff	Yes	NERC staff supports the changes to the Measures.
SERC Planning Standards Subcommittee	Yes	
Northeast Power Coordinating Council	Yes	
Hydro One Networks Inc.	Yes	
SERC Dynamics Review Subcommittee	Yes	
MRO's NERC Standards Review Subcommittee	Yes	
Pepco Holings, Inc - Affiliates	Yes	
IRC Standards Review Committee	Yes	
Exelon Transmission Planning	Yes	
Southern Company	Yes	
Western Area Power	Yes	

Organization	Yes or No	Question 10 Comment
Administration		
PacifiCorp	Yes	
Duke Energy	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Orlando Utilities Commission	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
TVA Transmission Planning & Compliance	Yes	
Independent Electricity System Operator	Yes	
South Carolina and Gas	Yes	
California ISO	Yes	
Seattle City Light	Yes	
ISO New England Inc.	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	

Organization	Yes or No	Question 10 Comment
United Illuminating	Yes	
Hydro-Quebec TransEnergie	Yes	
National Grid	Yes	
American Transmission Company	Yes	
American Electric Power (AEP)	Yes	
Tri-State Generation & Transmission	Yes	
GTC	Yes	
Pacific Gas and Electric Company	Yes	
Northeast Utilities	Yes	
Consolidated Edison Co. of New York, Inc.	Yes	
NBSO	Yes	
Central Maine Power Company	Yes	
Oncor Electric Delivery	Yes	
New York State Electric & Gas Corp	Yes	
Progress Energy	Yes	

Organization	Yes or No	Question 10 Comment
ERCOT ISO	Yes	
Tucson Electric Power Company	Yes	
New York Independent System Operator	Yes	
Xcel Energy	Yes	
Southern California Edison Company	Yes	

7. The SDT has revised the Requirement R8 VSL based on industry comments to the initial ballot. If you do not support these changes, please specify why you disagree and include specific alternative language to resolve your concern.

Summary Consideration:

The SDT made the following clarification due to industry comments:

> **4.3.1, bullet #1**: Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

The VSL was not changed as the majority response was that the industry is in general agreement with the VSL.

The SDT did not pose questions for items that were not redlined, i.e., changed, in this posting since those items not redlined were considered by the SDT as sufficiently vetted by the industry through the various phases of the project to date. However, the SDT has reviewed all comments regardless of whether specific questions were asked and has considered the comments.

Organization	Yes or No	Question 11 Comment
Northeast Power Coordinating Council Consolidated Edison Co. of New York, Inc.	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to Bulk Power System reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary. Should the VSLs for Requirement 8 remain, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.If Requirement 8 and 8.1 are retained, they should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. Other comments not addressed by this Comment Form as follows: Section 3.3 - The last sentence of 3.3.1 should be removed. This is addressed in PRC-023. Line ratings are addressed in PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined, and to help eliminate any confusion that it may introduce

Organization	Yes or No	Question 11 Comment
		into the standard it will be worthwhile for the SDT to define this term. Several specific examples from previous comments on sensitivity analysis and guidance for base case assumptions: The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions. As for allowing con-consequential load loss for Categories P1 through P5, suggest approval at the Regional level, with a concept of allowing it in a "local area" that does not impact BPS reliability. All references to 300 kV in document should be replaced with EHV (for example in the Introduction, Section 5).The first phrase of Note 3 on p. 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."
IRC Standards Review Committee	No	(AESO is not a party to the following comments since its VSLs are set by the Alberta regulatory authority.)Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website. Should the SDT decide to include the VSLs for Requirement 8, we would recommend revising to use a percentage approach rather than applying a violation to a Planning

Organization	Yes or No	Question 11 Comment
		Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Southern Company	No	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” Also, we wish to make a comment on footnote #13 of Table 1. 13. Applies to any of the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, & 67), voltage (#27 & 59), directional (#32 & 67), and associated tripping (#86 & 94) relays.
Florida Reliability Coordinating Council, Inc - Transmission Working Group	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified to replace distribute with “make available:, so the new requirement would read as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
PacifiCorp	No	The language for Requirement R8 is ambiguous with regard to which adjacent entities must request in writing the results of the Planning Assessment. The language should be clarified to read: “Upon request made in

Organization	Yes or No	Question 11 Comment
		writing, each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, adjacent Transmission Planners, and any other functional entity that has a reliability related need.” The Requirement R8 VSL language should also be revised accordingly.
ReliabilityFirst	No	TPL-001-2 Draft 5 is much better than Draft 4.There is still one significant concern, that I do not believe the drafting team adequately addressed. It is unclear as to what “Planning Assessment results” and “results of its Planning Assessment” entail. The Draft 5 response that “Planning Assessment” is a defined term does not fully address this concern. “Planning Assessment results” or “results of its Planning Assessment” is not necessarily the same thing as “Planning Assessment”. As written, “Planning Assessment results” or “results of its Planning Assessment” could be anything from a single sentence, to a few brief high level paragraphs, to a detailed and technically complete Planning Assessment. The Standard needs to more clearly state what is required in the report to other entities. Based on the drafting team response in Draft 4, it seems that replacement of “Planning Assessment results” or “results of its Planning Assessment” with the term “Planning Assessment” or “its Planning Assessment” would be appropriate. Violation Severity Levels: R8The failure to provide documented responses to documented comments to “Planning Assessment results” is deemed to be a higher severity level than failing to distribute “results of its Planning Assessment”. Failure to distribute denies functional entities an opportunity to comment, and could prevent coordinated planning, and thus should be deemed to be more severe than failing to provide documented responses to documented comments.
Lakeland Electric	No	The requirement to distribute the Planning Assessment should be more flexible and allow for making the Planning Assessment available, such that those entities that desire the information can have it readily available. R8 should be modified as follows: Each Planning Coordinator and Transmission Planner shall make available its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners and to any functional entity that indicates a reliability related need for the Planning Assessment results.
Orlando Utilities Commission	No	R8 should require that the PC and TP make available it's planning assessment results when requested, rather then requring the preemptive transmittal. There is no reliablity purpose served by providing unsolicited information.
US Bureau of Reclamation	No	The language implies that the responsible entity may choose to not distribute it is feels the entity making the request does not have a "reliability related need". It is not clear why that distinction is being made?
California ISO	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the

Organization	Yes or No	Question 11 Comment
		Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows: 8.1 If a recipient of the planning assessment final results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.For a Planning Coordinator (PC) who distributes the Planning Assessment to many different entities (to adjacent PCs, TPs, and other functional entities), a concern regarding the Requirement R8 VSL is that it is overly restrictive to apply a violation for failing to distribute the results of its Planning Assessment to only one PC, TP, or functional entity (and to apply a High VSL for failing to distribute to more than one entity), particularly since an entity's contact is subject to change over time, and since Measure M8 allows for publicly posting the results of its Planning Assessment to its website.Should the SDT decide to include the VSLs for Requirement 8, would recommend revising to use a percentage approach rather than applying a violation to a Planning Coordinator who fails to provide the results of its Planning Assessment to one PC, TP, or other functional entity (or applying a High VSL for failing to distribute to more than one entity.) Recommend applying a similar percentage approach to the VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1) to be considered for the TPL-001-2 R8 VSLs. For example, o Lower VSL: The responsible entity failed to provide the Planning Assessment final results to 5% or less of the required entities. o Moderate VSL: The responsible entity failed to provide the Planning Assessment final results to more than 5% up to (and including) 10% of the required entities. o High VSL: The responsible entity failed to provide the Planning Assessment final results to more than 10% up to (and including) 15% of the required entities. o Severe VSL: The responsible entity failed to provide the Planning Assessment final results to more than 15% of the required entities OR [the existing language for the Severe VSL].Explanation: The VSLs were modified for consistency with other standards and VSLs.Reference: Link to VSLs drafted by NERC Staff for Project #2007-23 VSLs (e.g., for FAC-013-1):http://www.nerc.com/docs/standards/sar/Staff_Proposed_VSLs_2010July27.pdf
Ameren	No	The sharing issues of requirement R8 are still not clear, therefore the R8 VSL is not clear. It is not clear if the intent of the SDT is for the PC to share the assessments with PCs and TPs are to share the assessments with TPs, or whether the intent is for the TP to share its assessments with its PC. Will posting the assessment to a secure web-site meet the intent of the requirement? Although the comment form is not designed to allow for such, we need to comment on R4.3.1: As written, it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations, regardless of whether high-speed reclosing is actually implemented. A suggested wording change for the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP."

Organization	Yes or No	Question 11 Comment
		Another comment needs to be made regarding the stability extreme event table: Changes were made in planning event P5 to concentrate on specific relay failures. The same changes need to be made for stability extreme events 2a, 2b, 2c, and 2d.The proposed standard will significantly increase the amount of work required to develop more detailed and complex system models, to perform and document the engineering studies to meet the performance requirements, and to develop the assessments necessary for compliance. All of these increased engineering activities are perceived to provide marginal benefit to the reliability of the bulk electric system, but will require significant increases in manpower across the industry. Further, the manpower is presently not available to develop these more detailed models and to perform these studies with any reasonable assuredness. It will be a continuing challenge to the industry to obtain and keep the engineering talent needed to perform these compliance activities for such marginal benefits.
Central Maine Power Company New York State Electric & Gas Corp	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We also have other comments not addressed by this Comment Form as follows - Section 2.7, Section 3.3, Section 4.3, and overall:Section 2.7 requires that Corrective Action Plans are included in each Planning Assessment and states “Such actions may include...” followed by a list of actions. Restricting allowable actions, and excluding runback/tripping of HVDC would have a direct impact on multiple existing facilities in New York and would adversely impact the reliability planning of the NYCA. Runback/tripping of HVDC must be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove “Tripping of Transmission elements where relay loadability limits are exceeded.” Section 4.3 - High speed reclosing is not defined.Overall - We have previously made comments which have not been addressed in the current version of the proposed standard. Support for the standard can at most be limited without addressing comments.

Organization	Yes or No	Question 11 Comment
		We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required. The requirements for sensitivity analysis already address issues going beyond what is expected to meet reliability requirements. Requiring extreme event analysis is requiring two layers of event analysis beyond what is required, and there is no requirement for corrective action if anything is identified. The standard is referring to requirements for sensitivity and other issues without a reference to base assumptions. The standard must describe base assumptions. To define a sensitivity condition, NERC must define base assumptions.
New York Independent System Operator	No	Requirement 8 is an administrative burden to TPs and PCs that adds no value to reliability. PCs should be including TPs, neighboring PCs and interested parties in its planning processes when developing the Planning Assessments. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.Furthermore, the requirement lacks a specified time frame to receive comments, thereby implying that TPs and PCs would be required to reply to comments forever following the finalization of a Planning Assessment. The NYISO proposes a limit of six months.Should the SDT decide to leave the VSLs for Requirement 8, Requirement 8.1 should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response as follows:If a recipient of the planning assessment final results provides documented comments on the results within 180 calendar days of the issuance of those final results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments.
NERC staff	Yes	NERC staff supports the changes to the VSL for Requirement R8.
SERC Planning Standards Subcommittee	Yes	Comments: We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP.” We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
Hydro One Networks Inc.	Yes	Requirement 8 is an administrative burden and adds little or no value to the BPS reliability. Therefore, the inclusion of a set of VSLs for Requirement 8 is unnecessary.
SERC Dynamics Review	Yes	We wish to make a comment on R4.3.1: it appears that this requires stability simulations of both successful

Organization	Yes or No	Question 11 Comment
Subcommittee		and unsuccessful high-speed reclosing for all contingency simulations regardless of whether high-speed reclosing is used on the faulted line. We suggest the following wording be used to replace the first bullet: “Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied."We wish to make a comment on the stability extreme event table: Changes were made in planning event P5 to narrow the focus to specific relay failures. The same changes are needed for stability extreme event 2a, 2b, 2c, and 2d.
MRO's NERC Standards Review Subcommittee	Yes	Other Comments:1. How are backup relays handled (TPL-002-0, R1.3.10 & TPL-001-2 R1 & P5)? What does FERC construe as normal system for a protection system. The TPL-001-2 R1 & P5, this standard doesn’t appear to address primary protection and how this handled. 2. Revise the Planning Assessment definition to more explicitly apply to the BES and the TPL-001 requirements. We suggest text of: “Planning Assessment: Documented evaluation of future Transmission System performance and Corrective Action Plans to remedy identified deficiencies in the BES from the steady state and stability performance requirements set forth in the TPL-001 standard.” 3. R2.1.5 - We propose replacing the term ‘major Transmission’ with “BES” because BES is a well defined term, while the term, ‘major Transmission’, is not. 4. Add R2.3.1 - We suggest the addition of a R2.3.1 requirement to emulate the distinction between the requirement to perform a short circuit assessment and conduct required studies or analysis to support the assessment (e.g. R2.1/R2.1.1 and R2.2/R2.2.1). We propose wording such as, “Perform an analysis for at least one year in the Near Term Transmission Planning Horizon.” This requirement would set an expectation that an analysis should be conducted to at least one or more years in the near-term planning horizon, rather than imply that an analysis of all five years in the near-term planning horizon must be conducted. 5. R2.7.4 - We suggest that the wording of R2.7.4 be the same as R.2.8.2. Otherwise, we propose that R2.7.4 and R2.8.2 be revised with wording like, “. . . implementation status of identified Corrective Action Plans for System Facilities and Operating Procedures.” to clarify that the identified system facilities and operating procedures refer only to those that were in the previous year’s Corrective Action Plans. 6. R3.3.1 - The term of ‘controls’ is ambiguous and not defined, unlike the term, ‘Protection Systems’, which is defined. Therefore, we suggest that this item be defined or more clearly described to avoid the risk of different and possibly contradictory interpretations by TPs, PCs, and auditors. 7. R3.3.1, bullet #1 - We suggest qualifying which generating units to consider and which voltage limits to simulate with revised wording like, “Trip generating units that are connected to the BES when actual or assumed minimum generator steady state or ride through voltage limits are known and simulations show voltages may fall below the voltage limit. If assumed voltage limits are used, then they should be included in the assessment”. The requirement should not apply to all relevant generating units until one of the MOD

Organization	Yes or No	Question 11 Comment
		standards requires all Generator Owners to provide their minimum generating unit voltage limits to the TP and PC. If the wording of R3.3.1 bullet #1 must be different from its counterpart, R4.3.1 bullet #2, then please explain the reasons for any differences. 8. R3.4.1 - Compliance with the requirement “to coordinate” is problematic and non-measureable We suggest replacing it with the requirement “to communicate”. 9. R3.5 - We interpret that R3.5 requires the TP and PC to conduct an evaluation of possible actions to reduce the likelihood or impact of extreme events, which produce the more severe impacts, if cascading outages may occur. Does the drafting team intend for the TP and PC to fulfill this requirement for at least one event in each of the five categories (i.e. 3 steady state and 2 stability) or in each of the 21 categories/sub-categories (i.e. 14 steady state and 7 stability). Also, if the resulting cascading outages do not result in any overloads, under-voltages, voltage collapse, or loss of generator synchronization, then should the evaluation of possible actions to reduce likelihood or impact be required? 10. R4.1.1 - We suggest that there should be some qualification of which generating units are referred to in this requirement. We propose that the requirement say, “No generating unit connected to the BES shall pull out of synchronism.” For example, some utilities include smaller generation units that are connected at voltages below 100 kV and even down to distribution voltage in their base cases. 11. R4.1.2 - We propose that the wording of this requirement be revised to reflect the same BES qualification of the generating unit that we noted in R4.1.1 above. 12. R4.3.1 - This requirement refers to high speed reclosing and we presume that this is special high speed reclosing that is completed in several cycles, rather than the normal high speed reclosing that is completed in a number of seconds. We recommend that the term high speed reclosing be more clearly defined for this sub-requirement. 13. R5 - This requirement should remove the criterion item, “post-Contingency voltage deviation”, because this criterion is not used widely enough in the industry to be well established criterion. 14. R8 - This requirement should be revised to limit the need to provide the Planning Assessment as follows “adjacent Planning Coordinators and adjacent Transmission Planners and to any registered functional entity...” This suggestion is added to the requirement to clarify that the word adjacent also applies to Transmission Planners and to clarify that the functional entity must be registered in order for the entity to be applicable to the requirement.
TVA Transmission Planning & Compliance	Yes	Additional TVA comments:TVA wishes to make a comment on R4.3.1: it appears that this requires stability simulations of both successful and unsuccessful high-speed reclosing for all contingency simulations. Does high speed reclosing occur in less than 60 cycles or 60 seconds? If a utility does not have reclosing on a

Organization	Yes or No	Question 11 Comment
		transmission line - then must the utility still perform stability studies assuming that there is reclosing? TVA suggests the following wording be used to replace the first bullet: "Successful high-speed reclosing and unsuccessful high-speed reclosing onto a fault, where such reclosing is applied, and where such additional simulations are deemed appropriate by the PC or TP." In R4.1.1, TVA is concerned that no generating unit shall pull out of synchronism in a local area only (thus not impacting the overall reliability of the BES) for Planning Event P1, while the standard does allow generator runback/tripping for the same event. Thus the generating unit may be tripped by a special protection scheme - but may not be tripped by an out of step relay. TVA believes that out of step relaying should be allowed for this unit tripping as long as this does not affect the overall reliability of the BES.
South Carolina and Gas	Yes	We wish to make a comment on the revisions to R4.3.1. We believe that the analysis of both successful and unsuccessful high speed reclosing for all cases is not justified and should be left to the discretion of the Transmission Planner.
ISO New England Inc.	Yes	Requirement 8 and 8.1, should be revised to reflect that comments only to the final Assessment (not drafts developed during a process) need a response and there should be a limit on the comment period as follows:If a recipient of the planning assessment final results provides documented comments on the results within 90 days of receipt, the respective Planning Coordinator or Transmission Planner shall provide a documented response to such recipient within 90 calendar days of receipt of those comments. We have other comments not addressed by this Comment Form as follows - Sections 2.7, 3.3, 4.3 and overall. R2.7 requires that Corrective Action Plans are included in each Planning Assessment and states "Such actions may include..." followed by a list of actions. Runback/tripping of HVDC should be added to the list. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing needs to be defined.
Hydro-Quebec TransEnergie	Yes	o All references to 300 kV in document should be replaced with EHV (In the introduction, section 5) o The first phrase of Note 3 on p 14 should be revised as follows: "Bulk Electric System (BES) level references include extra-high voltage (EHV) Facilities defined as those representing the backbone of the System, generally at voltage greater than 300 kV, and high voltage (HV) Facilities defined as those not representing the backbone of the System, as determined by the Planning Coordinator and approved by Regional Entity."

Organization	Yes or No	Question 11 Comment
National Grid	Yes	Other Comments:Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line ratings are addressed by PRC-023. PRC-023 requires coordination with the Reliability Coordinator. Remove "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined. We have previously commented on sensitivity analysis and guidance for base case assumptions. Also, extreme event analysis should not be mandated in this standard as no corrective action is required.
Tri-State Generation & Transmission	Yes	None regarding R8. The following comments refer to parts of the proposed standard for which no questions are asked.R4, Part 4.1.2: The response to our previous comment indicated that our description was for a system Stability issue. R4 is addressing system Stability and we believe the comment still applies and that it was not answered in the response. We have two issues with 4.1.2: Sometimes out-of-step (loss of generator synchronism) is better mitigated through islanding by tripping transmission rather than by tripping generators; the second point is that the ability of present modeling programs does not include the capability to model all types of impedance relays and their associated OOS blocking and tripping capabilities that are available. R4, Part 4.3.1: The third bullet implies that all impedance relays (and perhaps others) will need to be modeled in the stability databases. We question whether the existing simulation programs can accommodate this large magnitude of data inclusion and whether there is any benefit to BES reliability. Certainly using generic models rather than actual models would be of no benefit. We recommend changing the third bullet to "Evaluation of Protection System behavior when transient power swings are detected or predicted to have impedance characteristics that may approach relay operating characteristics."
Northeast Utilities	Yes	No comments on Question 7.Other Comments: As detailed below, NU has other comments that are not addressed by this Comment Form as follows - Section 3.3, Section 4.3, Non-Consequential Load Loss as referenced in the events Table 1 and studies using extreme event contingencies. Section 3.3 - NU believes that the last sentence of Part 3.3.1 should be removed since this is handled by PRC-023. Line ratings are addressed by PRC-023 which requires coordination with the Reliability Coordinator. NU suggests the removal of the following sentence: "Tripping of Transmission elements where relay loadability limits are exceeded." Section 4.3 - High speed reclosing is not defined and to help eliminate any confusion that it may introduce into the standard it will be worthwhile for the SDT to define this term. Non-Consequential Load Loss - Depending upon the resolution of "Project 2010-11, TPL Table 1, Footnote b" NU may have additional comments regarding this issue. Studies Using Extreme Event Contingencies: The requirements for sensitivity analysis already address issues

Organization	Yes or No	Question 11 Comment
		going beyond what is expected to meet the reliability requirements of the standard. Therefore, requiring extreme event analysis is requiring two layers of event analysis beyond what is required and there is no requirement for corrective action if a concern is identified.
NBSO	Yes	NBSO suggests considering rewording the VSL so that they address the failure to distribute the final results of planning assessments.
ERCOT ISO	Yes	ADDITIONAL COMMENTS: Short circuit analysis (R2.3 and R2.8) should only be applicable to TPs. Fault duty issues are typically local in nature and it would be an overlap for PCs to perform this same analysis done by the local Transmission Planner. Furthermore, R7 should be deleted and the responsibilities of each entity should be explicitly stated within the specific requirements. Previous Comment Unaddressed : Requirement 2.6.2: Reads as if a change is being made to an existing study. It is confusing. Possibly restate: "2.6.2 For steady state, short circuit, or stability analysis: previous studies can be used only if a material change to the system has not occurred or if a change that did occur does not impact the study area." R4.1.2 - Planning Coordinators do not perform protection coordination nor do they have access to the relay settings information required to do this analysis. This requirement should apply to Transmission Planners only because they perform system protection.The substantive scope of the standard is relative to Long-Term Transmission Planning Horizon and Near-Term Transmission Planning Horizon. The Purpose section is described in terms of the “planning horizon” generally. It may be worthwhile aligning the two to mitigate the potential for any confusion. ERCOT proposes the following revisions to the Purpose section: 3.Purpose: Establish Transmission system planning performance requirements within the relevant planning horizon (i.e. Long-Term or Near-Term) 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 addition, the “Time Horizon” for the Standard is “Long-Term Planning”. Obviously, this necessarily encompasses both Long-Term and Near-Term Transmission Planning Horizons. However, the scope of the Long-Term Planning time horizon is not readily apparent. ERCOT recommends appropriate revisions that clearly define the applicable time horizons.
MidAmerican Energy	Yes	

Organization	Yes or No	Question 11 Comment
Southern California Edison Company	Yes	
Pepco Holings, Inc - Affiliates	Yes	
Exelon Transmission Planning	Yes	
Western Area Power Administration	Yes	
Duke Energy	Yes	
NorthWestern Energy (NWMT)	Yes	
FirstEnergy	Yes	
Platte River Power Authority	Yes	
Manitoba Hydro	Yes	
Minnesota Power	Yes	
Independent Electricity System Operator	Yes	
Seattle City Light	Yes	
Los Angeles Department of Water and Power	Yes	
Idaho Power Co	Yes	
American Transmission Company	Yes	

Organization	Yes or No	Question 11 Comment
American Electric Power (AEP)	Yes	
GTC	Yes	
Oncor Electric Delivery	Yes	
Progress Energy	Yes	
Xcel Energy	Yes	
Tucson Electric Power Company	Yes	