NERC
NORTH AMERICAN ELECTRIC
RELIABILITY CORPORATION

Consideration of Comments on Assess Transmission Future Needs and Develop Transmission Plans — Project 2006-02

The Assess Transmission Future Needs and Develop Transmission Plans Drafting Team thanks all commenters who submitted comments on the 6th draft of the TPL-001-2 standard for Assess Transmission Future Needs (Project 2006-02). These standards and associated documents were posted for a 45-day public comment period from April 18, 2011 through May 31, 2011. Stakeholders were asked to provide feedback on the standards and associated documents through a special electronic comment form. There were 43 sets of comments, including comments from approximately 78 different people and approximately 69 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

No changes were made to the text of any Requirement. The SDT made several changes in response to comments submitted during the formal comment period and successive ballot that ended May 31, 2011.

- The 5th and 6th bullets of the Data Retention section to make the language in the data retention statements consistent with the language in the requirements.
- The third part of the Severe VSL for Requirement R1 to make the language consistent with the requirement.
- The VSL for Requirement R8 to make the language consistent with the language in the requirement.
- The Effective Date section of the Implementation Plan to make the language consistent with the language in the Effective Date section in the proposed TPL-001-2.
- The bullets in Requirement R3, Part 3.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.
- The bullets in Requirement R4, Part 4.3.1 were replaced with numbers because the bullets were inconsistent with NERC's protocol on the use of bullets in Requirements.

The SDT is requesting that this project be moved to the recirculation ballot stage.

All comments submitted may be reviewed in their original format on the standard's project page:

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

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the 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	Charles W. Long	SERC Planning Standards Subcommittee	X									X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pat Huntley	SERC Reliability Corporation	SERC	10
2.	Bob Jones	Southern Company Services	SERC	1
3.	Darrin Church	Tennessee Valley Authority	SERC	1
4.	Phil Kleckley	South Carolina Electric & Gas Co.	SERC	1
5.	John Sullivan	Ameren Services Co.	SERC	1
6.	Charles Long	Entergy Services, Inc.	SERC	1

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council, LLC	NPCC	10
2.	Gregory Campoli	New York Independent System Operator	NPCC	2
3.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
3.	Group	Jonathan Hayes	SPP Reliability Standards Development Team	X	X	X	X	X					

5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Brian Evans-Mongeon	Utility Services	NPCC	8
8.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
9.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
10.	Kathleen Goodman	ISO - New England	NPCC	2
11.	Chantel Haswell	FPL Group, Inc.	NPCC	5
12.	David Kiguel	Hydro One Networks Inc.	NPCC	1
13.	Michael R. Lombardi	Northeast Utilities	NPCC	1
14.	Randy MacDonald	Nerw Brunswick Power Transmission	NPCC	1
15.	Bruce Metruck	New York Power Authority	NPCC	6
16.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
17.	Robert Pellegrini	The United Illuminating Company	NPCC	1
18.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
19.	Saurabh Saksena	National Grid	NPCC	1
20.	Michael Schiavone	National Grid	NPCC	1
21.	Wayne Sipperly	New York Power Authority	NPCC	5
22.	Donald Weaver	New Brunswick System Operator	NPCC	1
23.	Ben Wu	Orange and Rockland Utilities	NPCC	1
24.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Additional Member	Additional Organization	Region	Segment Selection
1.	Charles Yeung	SPP	SPP	2
2.	John Allen	City Utilities of Springfield	SPP	1, 4
3.	John Fulton	Xcel Energy	SPP	1, 3, 5
4.	Mark Hamilton	Oklahoma Gas & Electric	SPP	1, 3, 5
5.	Michelle Corley	CLECO	SPP	1, 3, 5

	Additional Member	Additional Organization	Region	Segment Selection
6.	Nathan McNeil	Midwest Energy	SPP	1, 3
7.	Tony Gott	Associated Electric Coop, Inc	SERC	1, 3, 5
8.	Matt Bordelon	CLECO	SPP	1, 3, 5
9.	Valerie Pinamonti	American Electric Power	SPP	1, 3, 5

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
4.	Group	Denise Koehn	Bonneville Power Administration	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Berhanu Tesema	BPA, Transmission Planning	WECC	1
2.	Chuck Matthews	BPA, Transmission Planning	WECC	1
3.	Kyle Kohne	BPA, Transmission Planning	WECC	1
4.	Patrick Rochelle	BPA, Transmission Planning	WECC	1
5.	Kendall Rydell	BPA, Transmission Planning	WECC	1

	Group/Individual	Commenter	Organization	Registered Ballot Body Segment 1	2	3	4	5	6	7	8	9	10
5.	Group	Carol Gerou	MRO's NERC Standards Review Forum										X

	Additional Member	Additional Organization	Region	Segment Selection
1.	Mahmood Safi	Omaha Public Utility District	MRO	1, 3, 5, 6
2.	Chuck Lawrence	American Transmission Company	MRO	1
3.	Tom Webb	Wisconsin Public Service Corporation	MRO	3, 4, 5, 6
4.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
5.	Ken Goldsmith	Alliant Energy	MRO	4
6.	Alice Ireland	Xcel Energy	MRO	1, 3, 5, 6
7.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
8.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
9.	Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
10.	Scott Nickels	Rochester Public Utilties	MRO	4
11.	Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6
12.	Marie Knox	Midwest ISO Inc.	MRO	2
13.	Lee Kittelson	Otter Tail Power Company	MRO	
14.	Scott Bos	Muscatine Power & Water	MRO	

	Additional Member	Additional Organization	Region	Segment Selection
15.	Tony Eddleman	Nebraska Public Power District	MRO	1, 3, 5
16.	Mike Brytowski	Great River Energy	MRO	1, 3, 5, 6
17.	Richard Burt	Minnkota Power Cooperative, Inc.	MRO	1, 3, 5, 6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
6.	Group	Patricia Robertson	BC Hydro	X									

	Additional Member	Additional Organization	Region	Segment Selection
1.	Venkataramakrishnan Vinnakota	BC Hydro	WECC	2
2.	Pat Harrington	BC Hydro	WECC	3
3.	Clement Ma	BC Hydro	WECC	5
4.	Daniel O'Hearn	BC Hydro	WECC	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
7.	Group	Ed Davis	Entergy Services	X		X		X	X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Stan Jaskot	Entergy Services	SERC	5
2.	Terry Benoit	Entergy Services	SERC	6
3.	Joel Plessinger	Entergy Services	SERC	3
4.	Ed Davis	Entergy Services	SERC	1

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
8.	Group	Brandy A. Dunn	Western Area Power Administration	X					X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	Pete Kinney	Western Area Power Administration	MRO	6

	Group/Individual	Commenter	Organization	1	2	3	4	5	6	7	8	9	10
9.	Group	Sammy Alcaraz	Imperial Irrigation District	X		X	X		X				

	Additional Member	Additional Organization	Region	Segment Selection
1.	David Barajas		WECC	
2.	Marcela Caballero		WECC	
3.	Tino Zaragoza		WECC	1
4.	Jesus Alcaraz		WECC	3
5.	Diana Torres		WECC	4

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
6. Cathy Bretz			WECC 6										
10.	Group	Bill Middaugh	Tri-State Generation and Transmission Assn., Inc.	X		X		X					
	Additional Member	Additional Organization	Region / Segment Selection										
1.	Mark Graham	Tri-State G&T	WECC 1										
2.	Chris Pink	Tri-State G&T	WECC 1										
11.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
12.	Individual	Jim Eckelkamp	Progress Energy	X		X		X	X				
13.	Individual	Janet Smith	Arizona Public Service Company	X		X		X	X				
14.	Individual	John Bussman	Associated Electric Cooperative Inc	X		X		X	X				
15.	Individual	Thad Ness	American Electric Power	X		X		X	X				
16.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
17.	Individual	Bernie Pasternack	Transmission Strategies, LLC								X		
18.	Individual	Joe O'Brien	NIPSCO	X		X		X	X				
19.	Individual	Scott Bos	Muscatine Power and Water	X		X		X	X				
20.	Individual	Sunitha Kothapalli	Puget Sound Energy, Inc.	X		X		X					
21.	Individual	Anthony Jablonski	ReliabilityFirst										X

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
22.	Individual	Michael Moltane	ITC	X									
23.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
24.	Individual	Joe Petaski	Manitoba Hydro	X		X		X	X				
25.	Individual	Tony Eddleman	Nebraska Public Power District	X		X		X					
26.	Individual	Robert Casey	Georgia Transmission Corporation	X									
27.	Individual	Jonathan Appelbaum	United Illuminating	X									
28.	Individual	Andrew Z.Pusztai	American Transmission Company, LLC	X									
29.	Individual	Michael Jones	National Grid	X		X							
30.	Individual	Tim E. Ponseti, VP	TVA TP&C	X									
31.	Individual	Michael Falvo	Independent Electricity System Operator		X								
32.	Individual	Alex Rost	NBSO		X								
33.	Individual	Alice Ireland	Xcel Energy	X		X		X	X				
34.	Individual	Christine Hasha	Electric Reliability Council of Texas, Inc.		X								
35.	Individual	Chris de Graffenried	Consolidated Edison Co. of NY, Inc.	X		X		X	X				
36.	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
37.	Individual	Claudiu Cadar	GDS Associates, Inc.	X									
38.	Individual	David Thorne	Pepco Holdings Inc	X		X							
39.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
40.	Individual	Marie Knox	MISO		X								
41.	Individual	Gregory Campoli	New York Independent System Operator		X								
42.	Individual	Kirit Shah	Ameren	X		X		X	X				
43.	Individual	Darryl Curtis	Oncor Electric Delivery Company LLC	X									

1. **The SDT has made revisions to the requirements language of TPL-001-2 based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments with clear indications as to which requirement you are commenting on.**

Summary Consideration: Several commenters stated that Requirement R1, Part 1.1.5 should not include interchange because interchange introduces economic considerations into a Reliability Standard. The SDT explained that the requirement is to include known commitments for interchange and therefore the requirement is not for economic purposes, but rather planning to meet obligations.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT believes that the requirement to conduct the annual study on one of the study years in the Long-Term Transmission Planning Horizon ensures that the planner conducts a new study annually to evaluate the System improvement needs in the Long-Term Transmission Planning Horizon, even if they utilize qualified past studies for the Near-Term Transmission Planning Horizon cases.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability for planners to adequately model the dynamic behavior of Load. The SDT explained that since it is important to correctly model the characteristics of the Load, it believes that the requirement to represent the dynamic behavior of the Load is needed to ensure BES reliability.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

A number of commenters expressed concern that Footnote 12 was not appropriate or that this standard should be delayed until FERC approved TPL-002-1 Footnote 'b'. The SDT explained that Footnote 12 was consistent with language in the recent NERC Board of Trustees approved TPL-002-1 Footnote "b" and that this standard should not be delayed until FERC rules on the other standard.

No changes were made to requirements due to industry comments to question 1. However changes were made to the wording of the Implementation Plan to make it consistent with the language in the Effective Date section of the standard. Also, the language in the data retention section was changed for bullets five and six to make it consistent with the language in the requirements – no changes were made to the timeframe for data retention.

DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5.

DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6.

Organization	Yes / No	Question 1 Comment
Lower Colorado River Authority	Ballot Comment	1. R2 (2.5): The requirement for stability assessment in years 6-10 should be limited for new generation interconnections or for planned major transmission system improvements that have regional impact. The standard should clarify the 'material changes' that would necessitate stability planning assessments and documentation. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, LCRA TSC suggests the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.

<table>
<tr><th>Organization</th><th>Yes / No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3"> Response: For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. 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. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments. </td></tr>
<tr><td>Florida Municipal Power Agency</td><td>Ballot Comment</td><td> FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation) </td></tr>
<tr><td colspan="3"> Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made. Table 1, bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop the simulations for their studies without always referring back to the requirements language. No change made. </td></tr>
<tr><td>Madison Gas and Electric Co.</td><td>Ballot Comment</td><td>Please revise the words "System" to "system" or preface with BES System. NERC defines System to include distribution components. Plus this Standard is only applicable to PCs and TPs.</td></tr>
</table>

Organization	Yes / No	Question 1 Comment
MidAmerican Energy Co.	Ballot Comment	Resolve the conflict between R2 and other requirements in the TPL standards by replacing the term, “System” with “BES” in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, “System”. These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term “System” includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
City of Austin dba Austin Energy Lower Colorado River Authority	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote ‘b’, regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity’s Board of Directors, local public utility commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Regarding R2 (2.5): The value of annually assessing system stability for years 6-10 is questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the ‘material changes’ that would necessitate stability planning assessments and documentation. Regarding the R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request.
Response: The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. 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. No change made.		

Organization	Yes / No	Question 1 Comment
For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
City of Green Cove Springs City of Vero Beach Fort Pierce Utilities Authority Keys Energy Services	Ballot Comment	R7is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important considerations and not ambiguous. No change made.		
Alberta Electric System Operator	Ballot Comment	With respect to R2, Part 2.7.1 which lists system deficiencies and the associated actions needed to achieve System performance, the 3rd and 4th bullet identify the following actions as being acceptable. :Installation or modification of automatic generation tripping as a response to a single or multiple contingency to mitigate Stability performance violations. :Installation or modification of manual and automatic generation runback/tripping as a response to a single or multiple Contingency to mitigate steady state performance violations. The current Alberta transmission policy does not allow for the tripping or runback of generation for a single contingency; however for multiple contingencies it is acceptable. The AESO will bring TPL-001-2, with any modifications, through the standard development consultation process in Alberta and ultimately to the Alberta Utilities Commission for approval.
Response: The list in Requirement R2, Part 2.7.1 are examples of actions that are acceptable under the NERC Reliability Standard, however, certain actions may not be acceptable under state, provincial, or other regulatory policies or requirements and are not intended to supersede other regulations or policies.		

Organization	Yes / No	Question 1 Comment
ReliabilityFirst	Yes	1. In requirement 4.3, the high speed recloser time of 1 second is too restrictive. We suggest that the time be expanded to 2 seconds to capture all reclosing operations that might impact stability studies.We interpret the use of bullet points in Requirement 4.3.1 to mean that any one of the statements can be included in the analyses. In this requirement, the use of bullet points should be removed and replaced with language that requires all of the statements to be included in the analyses. We strongly believe that the language needs amended in requirement 4.3.1, such that, we will reconsider our voting position. 2. In Table 1 labeled Steady State and Stability Performance Extreme Events we contend that the change to “relay failure” is unnecessarily limiting. The previous use of Protection system was satisfactory. Protection System is a defined term and encompasses many components that may fail and not just the relay. 3. In table 1 Steady State & Stability Performance Planning Events under P5 “non-redundant” needs to be better defined. We suggest saying in a footnote that two devices do not need to be identical in order to be redundant. Redundant relays or relay schemes need to have the same performance level to be considered redundant but do not need to be identical equipment.
Response: The SDT believes that high speed reclosing is less than one second and has not received other comments that the time should be extended. The SDT believes that the language is clear that any of the three items shall be included in the analyses, if applicable. No change made. Table 1, Extreme Events, Stability Item 2 – The SDT made the language consistent with the language in the Planning Events to ensure that the planner was evaluating Stability based on performance of the System after the failure of a relay to operate and the planner should not address the many component failures that could create different failure modes. No change made. The SDT believes that non-redundant is understood by the industry. No change made.		
Bonneville Power Administration	Yes	1. If current study is performed to assess the system, there is no need to supplement with past studies. o Suggested language for R2.2:- For the planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed and be supported by the following annual current study or qualified past studies as indicated in Requirement R2, Part 2.6 2. Load models should be consistent across the region o Suggested language for R2.4.1:- System peak load for one of the five years. System peak load levels shall include a the latest load model developed by the regional planning coordinator which represents the expected dynamic behavior of loads that could impact the study area, considering the behavior of induction motor loads. 3. R2.5 is redundant and should be deleted. It is already included in R1.1.3 and R2.6.2.4. R3.5: This

Organization	Yes / No	Question 1 Comment
		standard requires mitigating the consequences of extreme events. Requiring potentially very costly mitigation actions for very low probability event is unnecessary burden to utilities. o Suggested language for R3.5. Those extreme events in Table 1 that are expected to produce more severe System impacts shall be identified and a list created of those events to be evaluated in Requirement R3, Part 3.2. The rationale for those Contingencies selected for evaluation shall be available as supporting information. Evaluation of the risk, consequences and adverse impacts of the event(s) shall be conducted.
Response: For Requirement R2, Part 2 - If the planner chooses to annually complete current studies to assess the system, the planner is not required to use past studies, but rather is allowed to use information from past studies in lieu of completing additional current studies. No change made. For Requirement R2, Part 2.4.1 – Not all Transmission Planners and Planning Coordinators are under a regional Planning Coordinator. However, for areas with a regional Planning Coordinator, that regional Planning Coordinator may have a requirement for all Transmission Planners and Planning Coordinators in its area utilize the regional Load model. No change made. Requirement R2, Part 2.5 is not redundant since the referenced requirements do not require the planner to assess the impact in the Long-Term Transmission Planning Horizon. The requirement is that the planners assess the impact of proposed material changes and have corrective action plans to resolve concerns from those proposed changes. The planner is not required to implement the corrective action plans unless the proposed material changes occur and the issues remain unresolved. No change made. Requirement R3, Part 3.5 – The SDT does not believe that the suggested language adds clarity and is also concerned that evaluation of possible actions to reduce the likelihood or mitigate the consequences and adverse impacts of the event are not required by the proposed language. No change made.		
Ameren Services	Ballot Comment	(1) Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. (2) For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow, stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. (3) The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent. (4) Overall,

Organization	Yes / No	Question 1 Comment
		we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities.
Response: For Requirement R2, Part 2.4.1, the SDT believes that there are models available that account for the dynamic nature of the Load. No change made. For Measurements M3 and M4, the planner is required to retain evidence that they completed the tasks required in each sub-part of Requirements R3 & R4. These sub-parts require evidence including steady state power flow, Stability and short circuit. Further, the Contingency lists are specifically required in Requirement R3, Parts 3.4 & 3.5 and Requirement R4, Parts 4.4 & 4.5. No change made. The SDT disagrees that the standard is too restrictive about the system conditions to be evaluated. The SDT believes that this standard is a significant improvement and adds needed clarity to the existing TPL standards. No change made.		
New York State Reliability Council	Ballot Comment	1. In R1.1.5, known commitments for Firm Transmission Service, plus other Interchange that does not violate reliability constraints - it is imperative to model other Interchange after accounting for all existing and planned Firm Transmission Service to ensure that reliability-based transactions are not confused with economic interchange. 2. In R2.2.5, the current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already evaluated as part of category P6 in Table 1, additional studies should not be required; however, spare equipment strategies could be assessed in the context of the planning assessment. 3. In R2.2, the language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study.
Response: The SDT selected known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made. In Requirement R2, Part 2.1.5, the requirement is for the planner to make an assessment of the loss of long lead time (>1 year) equipment, unless the entity's spare equipment strategy can mitigate the issue in less than one year. Therefore, in those instances, the system will be evaluated against the system with the component out of service (multiple Contingencies). While P6 will simulate the same set of outages, the requirements of P1 and P2 are different than P6. Therefore, the planner needs to make an assessment of their system under the more stringent performance requirements. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made.		

Organization	Yes / No	Question 1 Comment
Tennessee Valley Authority	Ballot Comment	1. TVA is concerned about the additional studies, modeling, and projects that must be performed to meet this proposed standard. TVA believes that this amount of work will have little overall improvement on the reliability of the BES. 2. TVA believes that the 7 year implementation plan allowed for “Raising the bar” facilities does not allow sufficient time for TVA to construct the required new facilities. TVA average time for constructing a new 500-kV line can be up to 10 years, given the lead time on ROW and following all NEPA requirements. TVA does understand that the team has language (R2.7.3) regarding the TP or PC inability to get the projects completed through no fault of its own; however, there is no safeguard that the entity will be found non-compliant if all the work cannot be accomplished in this time frame. 3. TVA believes that the footnotes b and c that allow for local load drop in the current TPL standards should still be allowed. TVA understands that this is addressed in FERC Order 693; however, the capital improvements to fix many of these issues will have little overall reliability gain for the Bulk Electric System. TVA believes that this is a local load reliability issue and not a BES concern. 4. TVA is concerned that no generating unit shall pull out of synchronism for Planning Event P1, while the standard does allow generator runback/tripping for the same event. TVA believes that this requirement is overly burdensome without providing any material improvement in system reliability. Does distributed generation have to meet the same requirements for not pulling out of synchronism as a large nuclear unit? 5. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.

Response: 1) The SDT appreciates the concern about additional work compared to the reliability benefits. The SDT believes that the changes within the proposed standard represent the appropriate work to ensure BES reliability. No change made.

2) The SDT believes that the Implementation Plan gives entities the necessary time to develop and implement Corrective Action Plans. No change made.

3) The SDT incorporated the language in Footnote 12 that was approved in Project 2010-11 TPL Table 1 Footnote B. No change made.

4) The SDT does not believe that any generator should pull out of synchronism for a single Contingency. No change made.

5) While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant “raising of the bar” for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment.

Organization	Yes / No	Question 1 Comment
Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS? C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, 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." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made.		

<table>
<tr><th>Organization</th><th>Yes / No</th><th>Question 1 Comment</th></tr>
<tr><td colspan="3">Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made.

Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made.

Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.</td></tr>
<tr><td>Modesto Irrigation District</td><td>Ballot Comment</td><td>Both Sections 2.1.4 (seven sensitivities) and 2.4.3 (five sensitivities) require sensitivity studies to be run for all planning events and for all years specified , which increases the number of required studies beyond a reasonable and manageable limit.

Also, both Section 2.1.4 and 2.4.3 specify that running studies over "...a range of credible conditions that demonstrate a measurable change in System response (performance)." must be completed, yet using "credible conditions" and also "demonstrating a measurable change in System response (performance)", may be mutually exclusive. "Measurable change in System response (performance)" is open to a broad interpretation, which increases the risk that the auditor may very likely interpret it differently than the utility system planner. The definition of the extreme events that have to be analyzed has been made nebulous, where in the existing standards they are quite specific.

Requirement 2.1.5 requires the modeling of the loss of any system element that does not have a back-up or spare available sooner than 1 year, as part of the system normal state. It is not clear why using 1 year of loss of use for a system element is being used as the triggering point requiring further system enhancements. Thank you.</td></tr>
<tr><td colspan="3">Response: Requirement R2, Part 2.1.4 and Part 2.4.3 do not require an unreasonable amount of sensitivities, since they both state the planner must “vary one or more of the following conditions”. No change made.

Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. No change made.

Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made.</td></tr>
</table>

Organization	Yes / No	Question 1 Comment
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed important issues that were raised during the first ballot. Please see specific responses to your comments where they were submitted.		
Luminant Energy	Ballot Comment	Our most significant concerns are related to the following: (1) The requirements for Sensitivity Analysis are not stringent enough. (2)Studies should include variations in the duration and timing of transmission outages. “Anticipated” outages should be included in the studies and not just “known” transmission outages. It is our experience that only including “known” outages drastically under represents the actual number of transmission outages. (3) Major equipment outages lasting three or more months, as a result of Spare equipment strategies should be included in studies. The time limit of one year as specified in the Standard is too lax. Specific suggested language: 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months or any known outage(s) of generation or Transmission Facility(ies) that will extend into the high stress period of the BES. 2.1. For the Planning Assessment, the Near-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies (as indicated in Requirement R2, Part 2.6, as follows). Qualifying studies shall include the following conditions: Add language between 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. Suggested wording: All planning studies must recognize and make provision for secure delivery of each of the Ancillary Services (eg Operating Reserve). In no case shall these studies double count capacity as being available for congestion management and Ancillary Services unless processes are in place to allow for location specific deployment of these Ancillary Service reserves for congestion management purposes.

Organization	Yes / No	Question 1 Comment
		2.1.4 (bullet 7) Duration and timing of anticipated Transmission outages such as required maintenance activities. 2.1.4 (bullet 8 added) Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.1.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied. 2.4.3. For each of the studies described in Requirement R2, Parts 2.4.1 and 2.4.2, sensitivity case(s) shall be utilized to demonstrate the impact of changes to the basic assumptions used in the model. 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 performance: â€¢ Load level, Load forecast, or dynamic Load model assumptions. â€¢ Expected transfers. â€¢ Expected in service dates of new or modified Transmission Facilities. â€¢ Reactive resource capability. â€¢ Generation additions, retirements, or other dispatch scenarios. â€¢ Duration or timing of anticipated Transmission outages such as required maintenance activities. â€¢ Reasonable variations of anticipated generator availability after accounting for equivalent forced outage rate. 2.4.4. P1 events in Table 1, with known outages modeled as in Requirement R1, Part 1.1.2, under those System peak or Off-Peak conditions when known outages are scheduled. 2.4.5 If an entity's spare equipment strategy could result in the unavailability of major Transmission equipment that would cause an outage of three months or more, (such as a transformer) the impact of this outage on System performance shall be studied.

Response: 1) The sensitivities addressed in Requirement R2, Parts 2.1.4 and Part 2.4.3 allow the planner to use engineering judgment to determine the sensitivities to be completed. Since sensitivities are included to ensure that the planner evaluates alternative conditions, it is necessary to allow flexibility to evaluate different types of changes that could occur. No change made.

2) Reliability Standards are the minimum requirements and if conditions warrant, entities may add additional outages to be evaluated in their planning studies.

Organization	Yes / No	Question 1 Comment
No change made. 3) Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. For Requirement R2, Part 2.1, the SDT did not add language between Parts 2.1.3 and 2.1.4 to account for generation limitations due to Ancillary Services. The proposed addition assumes a particular market structure and that market structure is not uniform across North America. The "projected System conditions" in Requirement R1 would be violated if an entity double counted its Ancillary Services. No change made. Requirement R2, Part 2.1.4, bullet 7 & 8 are examples of sensitivities and the examples provided would address those contemplated by the SDT. No change made. Requirement R2, Part 2.1.5 uses one year as a typical definition of a long lead time for equipment, so that the planner will assess their system performance without that equipment over peak periods. No change made. Requirement R2, Part 2.4.3 – Since the five conditions for sensitivities have been vetted through six postings, the SDT did not add the two proposed conditions. No change made. Requirement R2, proposed 2.4.4 – Since the known outages are already included in the cases, as required by Requirement R.1, Part 1.1.2, there is not a need to require specific studies that include them – No change made. Requirement R2, proposed Part 2.4.5 – The proposed requirement is already contained in Requirement 2, Part 2.1.5 and does not need to be duplicated here. The SDT has used the typical one year time period to define long lead time for equipment and believes that three months is too short a time period for this requirement. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT believes that sharing the Planning Assessments with adjacent Transmission Planners and Planning Coordinators is an important component of the planning process. The SDT did not change the VRF. The previous change reflects the latest guidelines on the topic.		

Organization	Yes / No	Question 1 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Platte River Power Authority	Ballot Comment	Stability requirements R4.1.2, along with the second and third bullets of R4.3.1, could be misunderstood to require the development of comprehensive relaying models for all Facilities represented in the stability model. These requirements should be made clear that Stability studies are to simulate the effects of relaying (tripping certain Facilities) and not require relaying models to trigger and cause the effects.
Response: The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made.		
GDS Associates, Inc.	No	1. Footnotea. Footnote should state "Draft 7" instead 2. Requirement R1a. Time Horizon should include both Near-term and Long-term Planning3. Requirement R2a. Time Horizon should include both Near-term and Long-term Planningb. Requirement R2, Part 2.1 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o The term "Qualifying studies" from the last sentence is referring to the qualified past studies, or the annual studies, or both actually? Suggesting adjusting the verbiage so it would not create confusion. o Subpart 2.1.4- Requirement R2, Part 2.1.1 and Part 2.1.2 are referring to system conditions, not studies. The second sentence may be subject of non-objective interpretations and may generate burdensome and

Organization	Yes / No	Question 1 Comment
		unrealistic amount of work. The requirement should state instead "For each of the system conditions described in Requirement R2, Part 2.1.1 and Part 2.1.2, the studies shall include sensitivity cases utilized to demonstrate whether there is any significant impact due to changes on the basic assumptions used in the model. The analysis, by case, may contemplate varying one or more of the following conditions:" o Subpart 2.1.5- We suggest adjusting the time threshold of potential equipment unavailability in order to be consistent with the time frame for the "known Transmission outages". c. Requirement R2, Part 2.2 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o While the Near-Term portion of the Planning Assessment details the premises of the study, the Long-Term is lacking in such thing. d. Requirement R2, Part 2.3 o Although both the steady-state and transient stability studies are required for the Near-Term and Long-Term, the short-circuit study is required only for the Near-Term. This is big disconnect, because there can be stability analyses conducted without a short-circuit assessment. o Breakers should be checked for their breaking capability, as well as to withstand the fault. All other disconnecting equipment, as well as current transformers in particular shall be also verified for their withstand capabilities. The current statement should be replaced with "The short circuit analysis portion of the Planning Assessment shall be conducted annually addressing the Near-Term and Long-Term Transmission Planning Horizon and can be supported by current or past studies as indicated in Requirement R2, part 2.6. The analysis shall be used to assess performances of transmission elements affected by a potential increase of short-circuit contributions to fault" e. Requirement R2, Part 2.4 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. o Similar with 2.1, the last sentence should read "The studies should include the following conditions:" o Subpart 2.4.1- We believe that the dynamic behavior of the load cannot be accurately estimated beyond current time. We are concerned about the effort required to ascertain the dynamic response of the load. As for the "Loads that could impact the study area" the standard doesn't include any directions in how an entity will identify these loads. Perhaps the standard should provide guidelines to determine which loads would impact the study area. o Subpart 2.4.3- See comments from Subpart 2.1.4f.

Organization	Yes / No	Question 1 Comment
		Requirement R2, Part 2.5 o The inclusion of the words "For the Planning Assessment" it seem unnecessary as long as main requirement R2 is only about the Planning Assessment and nothing else. g. Requirement R2, Part 2.6 o Subpart 2.6.2- We agree with the suggested changes as responding to previous commentsh. Requirement R2, Part 2.7 o Subpart 2.7.1- We disagree with the implemented changes. The standard should not include examples. If needed, a white paper can accompany the standard. We suggest adjusting the last sentence to read “Such actions may include, but are not limited to, the following:” i. Requirement R2, Part 2.8 o This should apply to all disconnecting equipment and CT in particular with respect not only to their interrupting duty, but to their withstand capabilities also. See comment on Part 2.3.4. Table 1a. Footnote 9 o With respect to the Curtailment of Firm Transmission Service we suggest SDT to revise the language in order to be consistent with the Implementation Plan. 5. Measure M1a. This measure it is hard to read. For simplicity, we suggest adjusting this measure to read "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 data consistent with MOD-010 and MOD-012, and the models reflect the System conditions in accordance with Requirement R1." 6. Measure M7a. The measure encompasses the particular scenario where the parties involved have reached an agreement for performing the required studies. In order to cover situations where the parties have not reach an agreement, the measure should read "Each Planning Coordinator, in conjunction with each of its Transmission Planners, shall provide dated documentation on roles and responsibilities, such as meeting minutes, agreements, and e-mail correspondence that identifies all individual and joint responsibilities for performing the required studies and Assessments in accordance with Requirement R7." 7. Compliancea. Data retention o The 5th bullet should read "The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5." o The 6th bullet should read "The documentation specifying the criteria or methodology used to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding since the last compliance audit in accordance with Requirement R6 and Measure M6." o The 7th bullet should be reworded in accordance with suggested changes at M7.

Organization	Yes / No	Question 1 Comment

Response: 1. This is the sixth time that this standard has been posted for comments. The reference to a seventh posting on the web site is because the standard was posted once for informational purposes. No change made.

2. Requirement R1. Per the standards process, the Time Horizon for this standard is Long-term Planning; which includes both the Short-Term and Long-Term Planning Horizon. No change made.

3. Requirement R2, Part 2.1 – “For the Planning Assessment” were added in a previous draft for clarity – No change made.

Requirement R2, Part 2.1 – “Qualifying Studies” could be either or both – No change made.

Requirement R2, Part 2.1.4 – The requirement is for the planner to have a completed study for each of the conditions in Parts 2.1.1 & 2.1.2. The requirement to complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made.

Requirement R2, Part 2.1.5 – The SDT determined that the impact of “known outages …” does not directly coorelate to the entity’s spare equipment strategy. No change made.

c. Requirement R2, Part 2.2 – “For the Planning Assessment” were added in a previous draft for clarity – No change made.

Requirement R2, Part 2.2 - The SDT limited the requirements in the Long-Term to allow the planner more latitude in that time frame, while ensuring that the planner conducted a Long-Term assessment of their portion of the BES. No change made.

d. Requirement R2, Part 2.3 - A planner may choose to complete a short circuit study in conjunction with its Long-Term Steady Steady State and Stability studies, but the SDT does not believe that the planner should be required to complete a short circuit study in the Long-Term Transmission Planning Horizon. No change made.

The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made.

e. Requirement R2, Part 2.4 – “For the Planning Assessment” were added in a previous draft for clarity . The SDT does not believe that replacing the last sentence as proposed adds any additional clarity. No change made.

Requirement R2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System Load and develop a representative model, however, the SDT should not dictate “how” the Load should be modeled. Those specific details must be included in the model by the individual planner. No change made.

Requirement R2, Part 2.4.3 - The requirement is for the planner to have a completed study for each of the conditions in Parts 2.4.1 & 2.4.2. The requirement to

Organization	Yes / No	Question 1 Comment
complete sensitivity studies has been included to ensure that the planner tests their system by stressing the system beyond what is within their base cases. Since the System conditions vary across North America, the relevant sensitivities are best determined by the planner. The proposed language does not convey the same intent. No change made. Requirement R2, Part 2.5 – "For the Planning Assessment" were added in a previous draft for clarity – No change made. Requirement R2, Part 2.7.1 – The SDT has included limited examples where we believe that additional clarity is needed. Since the list is clearly marked as "examples", the SDT believes the phrase "but not limited to", is not required. No change made. Requirement R2, Part 2.8 - The SDT agrees that any system element must be able to withstand the stresses that they may be subjected to, however, the standard must ensure BES reliability. Therefore, the SDT limited the requirement to the breakers since they protect other system elements from the fault. No change made. The Implementation Plan has been revised as suggested although the SDT wishes to point out that no dates have been changed. Measure M1 – While the suggested langauage is shorter it does not contain all of the terminology of the matching requirement and thus violates a basic guideline for measures. No change made. 6. Measure 7 – The suggested langauge doesn't change the assumed scenario cited and provides no additional clarity. No change made. 7. Data retention, 5th bullet – The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 5th bullet: The documentation specifying the criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and transient voltage response since the last compliance audit in accordance with Requirement R5 and Measure M5. Data retention, 6th bullet - The SDT agrees that for consistency the suggested terms should be added so that this bullet matches up with the language of the requirement. DR, 6th bullet: The documentation specifying the criteria or methodology utilized in the analysis to identify System instability for conditions such as Cascading, voltage instability, or uncontrolled islanding in support of its Planning Assessments since the last compliance audit in accordance with Requirement R6 and Measure M6. Data retention, 7th bullet – The SDT declined to make the suggested changes to Requirement R7 so no change is necessary for Measure M7.		
United Illuminating ISO New England Inc	No	a. 2.6.2 - What was the intent of this change? The old language seemed to work. The language should not be changed from the previous version. b. For 2.8.2 - Was the phrase changed to reflect modifications of facilities? If so the requirement should be

Organization	Yes / No	Question 1 Comment
		modified to read "Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of identified System Facilities and Operating Procedures with respect to modifications of facilities. Otherwise the requirement is unclear. c. For Section R8.1 - the proposed requirement conflicts with a long standing stakeholder process in our area which posts study results and allows comment within a defined period before studies are finalized. If this section is to be retained then it should be modified to only allow comments on Transmission studies less than one-year old. Requirement 8 and 8.1, should be revised to include 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. d. With respect to Table 1 - We suggest adding an event 6 to P1 to address the contingent loss of back to back HVDC Facilities. If not added to P1 then this event needs to be added somewhere in the standard. e. We don't agree with footnote 7 specifying that only one end of the line should be open for this condition. If the SDT is to keep this concept make P2 event 1 simply say "Opening one end of a line section w/o a fault" and delete the footnote. The existing footnote is unclear due to the use of language such as "possibly".

Response: a. Requirement R2, Part 2.6.2 was revised in response to comments that a "qualified" study may have material changes remote from the area of study and the previous version would not have allowed the use of that study. No change made.

b. Requirement R2, Part 2.8.2 – The added phrase – "of identified System Facilities and Operating Procedures" was added to ensure that it was clear what "implementation status" was referencing. No change made.

c. Requirement R8, Part 8.1 - The SDT does not believe that the requirement conflicts with other stakeholder processes and does not believe that a time limit is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.

d. Table 1, P1 back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.

e. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.

Organization	Yes / No	Question 1 Comment
Northeast Utilities	No	Definition of Terms Used in the StandardThe definitions of “Near-Term Transmission Planning Horizon” and “Year One” have been deleted from the standard, yet they are still used in draft 7. NU is concerned about voting in favor of this standard with these terms being defined by another project without a full discussion of the impact to this proposed standard. NU suggests repeating the definitions in this proposed standard. Requirement R1NU believes that the Normal System Conditions as stated in Requirement R1 should establish the base case conditions to be used for the assessment studies. However, a more detailed guideline for developing base cases should be addressed by the requirements. By just modifying the language of requirement R1 to indicate that “P0” constitutes the initial system conditions does not address this concern in Draft #7. A more detailed guideline for base case development is needed. Requirement R8The wording in requirement R8 needs to be amended to restrict comments to the most recent assessment only, for a limited period (say 3 months) after its release. The current wording appears to offer unlimited opportunity to comment on past assessments, long after their release. Footnote 7It appears there is a discrepancy between Footnote 7 and Event P2-1. Footnote 7 could be eliminated by rewording Event P2-1 as follows: “Opening one end of a line section w/o a fault”. Footnote 12NU did not agree with the clarification of Table 1 Footnote B of TPL-002 and did not vote for its approval. Therefore, NU does not agree with the same clarification being applied here for Non-Consequential Load Loss. For reference, below is NU’s comment on TPL-002 Table 1, Footnote B:”The revised language of Footnote b suggests that non-consequential demand interruption (load that is not directly served by the elements removed from service as a result of the contingency) could be used to mitigate reliability concerns arising from NERC Category B contingency events (i.e., single element contingencies). This language seems to encourage operational workarounds and adds burdens for operators of the system. NU believes this is not consistent with planning a highly reliable bulk electric system and thus does not support this weaker language”. General commentNU believes that a standard should contain statements and requirements that are direct and measurable. TPL-001-2 should not be an exception to this rule. Therefore, statements like “An objective” which appears in Footnotes 9 and 12 shall not be used.

Response: Definitions of Near-Term Transmission Planning Horizon and Year One are now approved NERC Glossary Terms and are no longer needed in this proposed standard. The definitions have been vetted through this process through the 1st six postings of this standard and were approved by the Commission in

Organization	Yes / No	Question 1 Comment
FAC-013. With the wide variety of system conditions and market structures across North America, the SDT chose not to establish a single set of conditions for a base case. Each planner shall establish their base case that meets their needs and their other regulatory requirements. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P2-1 – The SDT does not agree that there is a discrepancy between the Contingency and Footnote 7. Footnote 7 was utilized to clarify a specific condition that would need to be evaluated as a part of P2-1. No change made. Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote 'b'.		
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the revisions do not go far enough in addressing previously submitted comments. As written this standard would require restructuring of the functions in the ERCOT Region because several requirements are being assigned to the PC that are currently performed only by the TPs. It would not provide any reliability benefits to have the ERCOT PC assume these functions. Specifically, the following requirements should be modified: R2.1.5 should be clarified to be applicable to TPs only since the ERCOT PC does not have the information necessary to perform this analysis; R2.3 and R2.8 should be clarified to be applicable to TPs only since the ERCOT PC does not perform this analysis (it is performed by the TPs in ERCOT); R4.1.2 should be clarified to only apply to TPs because the ERCOT PC does not have the modeling information necessary to perform this analysis. Additionally, R2.1.4 and R2.4.3 should be removed because the requirements are subjective and there are no actions prescribed to be taken based on the sensitivity results. The Load model requirement should be removed from R2.4.1 because this would be better addressed in a MOD standard. Alternatively, R2.4.1 should be rewritten as "System peak Load for one of the five years with expected dynamic load models." A concurrent requirement should be incorporated to mandate DSPs and TPs to supply dynamic load model data to the PC to perform the required studies.
Response: Requirement R2, Part 2.1.5 requires that studies be completed based on an entity's spare equipment strategy. The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made.		

Organization	Yes / No	Question 1 Comment
Requirement R2, Parts 2.3 and 2.8 – The ERCOT Planning Coordinator could utilize Requirement R7 to document the individual and joint responsibilities for these studies and document the outcome of these studies. No change made. Requirement R4, Part 4.1.2 requires the Transmission Planner and Planning Coordinator to accurately represent the behavior of the system if a generator pulls out of synchronism. Therefore, this information is needed by each Transmission Planner and Planning Coordinator to ensure that the appropriate system response is modeled. No change made. Requirement R2, Parts 2.1.4 and R2.4.3 require the completion of sensitivity studies and allows the planner the discretion on which variables to vary. In addition, Requirement R2, Part 2.7 requires Corrective Action Plans to address issues that are present in multiple sensitivities. The MOD standards only require data to be submitted, and this requirement allows the variation of the forecasted load as one of the possible sensitivities. No change made. Requirement R2, Part 2.4.1 – The SDT believes that the drafted language more clearly explains the requirement than the proposed language. This requirement is for the planner to utilize models that reflect the dynamic nature of the load with an expectation that the planner will obtain the required information in Requirement R1 to determine how it is modeled. No change made.		
Independent Electricity System Operator	No	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
New York Independent System Operator	No	If the following recommended revisions are made to the requirements listed, subject to other unforeseen material changes, NYISO would no longer oppose the approval of this standard. Requirement R2.1.5 The current requirement language can be interpreted to require evaluation of the simultaneous unavailability of multiple long-lead-time components. Also, as a transformer outage is already

Organization	Yes / No	Question 1 Comment
		evaluated as part of category P6 in Table 1, additional studies should not be required, however spare equipment strategies could be ASSESSED in the context of the Planning Assessment. NYISO thus recommends this requirement be revised as follows: R 2.1.5 When an entity's spare equipment strategy could result in the unavailability of a major Transmission component that has a lead time of one year or more (such as a transformer), the impact of this possible unavailability on System performance shall be assessed with due regard to categories P0, P1, and P2 identified in Table 1. Requirement R2.2The language in this requirement is materially inconsistent with R2.1, unnecessarily requiring a current study. NYISO requests that R2.2 and the sub-requirement be revised as follows:2.2. For the Planning Assessment, the Long-Term Transmission Planning Horizon portion of the steady state analysis shall be assessed annually and be supported by current annual studies or qualified past studies as indicated in Requirement R2, Part 2.6. Qualifying studies shall include: 2.2.1. 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. Requirement R8.1There is an apparent open ended time frame afforded report recipients in their review of any Planning Assessment. This requirement should apply to only the most recent Planning Assessment. NYISO thus recommends the following language: 8.1. If a recipient of the most recent Planning Assessment results provides documented comments on the results, the respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments.
Response: Requirement R2, Part 2.1.5 is not the same as P6 – Table 1, however, the analysis for P6 could be utilized, if the results show there will not be load loss. Except for the outages being evaluated under P0, P1, and P2 for individual components out of service without a long term spare, the requirement does not require the evaluation of the simultaneous loss of multiple long lead time components. The SDT believes that the language "with due regard to" is not as clear as the proposed language. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
NBSO	No	Items that, if not addressed, will likely cause a negative vote from NBSO:R2.2 differs from R2.1, R2.3, R2.4 and R2.5 since R2.2 does not state that the annual assessment of the Long-Term Transmission Planning

Organization	Yes / No	Question 1 Comment
		Horizon portion of the steady state analysis can be supported by qualified past studies. Likely this omission is an oversight, but unresolved it can cause significant burden with little gain in reliability. Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The language of requirements R2.1.4 and R2.4.3 allowing the performance of one or more sensitivities appears to be inconsistent with language in R2.7.2 that requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. R7 (and M7) seem to indicate that the PC is ultimately responsible for determining the individual and joint responsibilities for performing the required planning assessment studies, with the expectation to consult and come to agreement with its corresponding TPs, but this interpretation is not clear. The correct interpretation of this requirement is important for resolving situations where a PC and TP do not agree on the assignment of responsibilities. Suggested wording: “Each PC shall work in conjunction with each of its TPs to determine and identify...” The language in R8 is unclear. One point of confusion relates to which entity is responsible for sending their Planning assessments to other entities. For example, who does a PC distribute their planning assessments to?:-Adjacent PC? (Seems to be clearly addressed)-TPs within its PC footprint? (Not clearly covered by the language in R8)-TPs adjacent to its PC footprint (Not clear if this is the responsibility of the PC, TP or both)In addition, the language in R8.1 appears to offer unlimited opportunity to request response to comments on any past assessment, long after their release. Providing limits in the langue of R8.1 is recommended in order to avoid unnecessary burden on PCs and TPs for little gain in reliability or constructive stakeholder involvement.

Response: Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made.

Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made.

Requirement R7 – The SDT believes that the current language addresses the various arrangements that could exist between the Planning Coordinator and Transmission Planner, better than the proposed language. If agreement is not reached, both the Planning Coordinator and the Transmission Planner would be required individually to perform all of the required studies. No change made.

Organization	Yes / No	Question 1 Comment
Requirement R8 – Each planner is required to distribute its Planning Assessment to all adjacent planners (Transmission Planners and Planning Coordinators). Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made.		
Hydro One Networks Inc.	No	Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the April 15, 2011, draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft (see our response to Question 3).
Response: Please see the response to Question 3.		
Manitoba Hydro	No	-R2.1.4 and R2.4.3: 'Expected transfers' should be replaced with 'Firm Transmission Service and Interchange' to correlate to R1 (R1.1.5 states 'Known commitments for Firm Transmission Service and Interchange' must be represented in system mode
Response: Requirement R2, Parts 2.1.4 and R2, Part 2.4.3 use the more inclusive term - Expected transfers – for sensitivities. The SDT does not want to unnecessarily restrict the transfers that could be evaluated as a part of a sensitivity study. No change made.		
Associated Electric Cooperative Inc	No	R2.4.1:The SDT has put a stronger emphasis on dynamic load behavior in stability studies (FIDVR, induction motor loads, etc) to be included in the peak models. The standard does indicate that "An aggregate System Load model which represents the overall dynamic behavior of the Load is acceptable." We feel that this should be clarified to ensure that the current modeling processes address what NERC desires with this requirement. At a minimum, we recommend that a grace period be implemented to account for any regional modeling practices which need time to implement dynamic load behavior per the draft standard. R2.5:It is our understanding that the Long-Term Transmission Planning Horizon does not require the sensitivity analysis which is required in R2.4 for the Near-Term Transmission Planning Horizon for the stability portion of the studies. R2.7:It is our understanding that Corrective Action Plan(s) do not need to be developed for performance violations observed in the sensitivity analysis (steady state and stability) unless the violation is observed in several sensitivities as it is indicated in R2.7.2: "Include actions to resolve performance deficiencies indentified in multiple sensitivity studies or provide rationale for why actions were not necessary". We feel

Organization	Yes / No	Question 1 Comment
		that this needs to be further clarified. R3.3.1:This requirement indicates that steady state analysis should include the effect of ride-through voltage limitations of generating units. We are having difficulty seeing how this is a steady-state issue. Generally one would expect a generator to experience ride-through voltage issues during faults. Per Table 1, P1.1 already require generator outages be taken - wouldn't that cover this issue? We feel that this needs to be further clarified. R3.4.1:This requirement states that "Transmission Planners 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". We feel that the coordination requirement should be removed from the standard as this will result in a massive increase in workload/time required to perform the TPL studies. AECI has several ties to adjacent Transmission Planners and Planning Coordinators - it will be a very time intensive task to coordinate with all of these parties. If the standard wants to ensure that the Contingencies overlap - we can agree to that, however we feel that the SDT needs to give some firm clarity on how far to go with it (how many buses away, only include ties, etc?). R4.1.2:We would like clarification on what is mean by "apparent impedance swings". R4.3.1:Is the intent of the SDT to require that generic or actual relay models be added to the stability models? We feel that this needs to be further clarified. R8:This requirement states that the Planning Assessments shall be distributed within 90 days of their completion to adjacent Planning Coordinators, Transmission Planners, and functional entities that have a reliability need (3rd Interconnection Customers?). We do not agree with the mandatory requirement of distributing the results of our TPL studies: We consider this information to be CEII We can agree to distribute the results upon request, but do not agree with the 30 day timeframe as more time will be needed to sign applicable Non-Disclosure Agreements, etc.

Response: Requirement R2, Part 2.4.1 – The SDT has allowed flexibility for the planner to determine how to meet this requirement. The implementation plan has allowed at least 24 months for coordination and development of modeling practices. No change made.

Requirement R2, Part 2.5 – Sensitivities are not required for years in the Long-Term Transmission Planning Horizon.

Requirement R2, Part 2.7 – Your understanding of the need for Corrective Action Plans to address deficiencies identified by sensitivity studies is correct. The SDT believes that the proposed language is clear. No change made.

Organization	Yes / No	Question 1 Comment
Requirement R3, Part 3.3.1 – Within the steady state analysis, the planner is required to represent the actual state of each generator based on the system response to a contingency and this includes voltage ride-through for generators. Table 1, P1-1 does not address this issue, since it is only a single generator outage and the requirements of Requirement R3, Part 3.3.1 could be a generator out of service (because it doesn't ride-through) as a result of a more severe contingency. No change made. Requirement R3, Part 3.4.1 – The SDT added the requirement to coordinate Contingency lists to ensure that these lists do not omit Contingencies on adjacent systems that may cause performance concerns. The SDT believes that most planners are already considering outages on the fringes of their neighbors system to ensure that they meet the performance requirements. The SDT does not agree that this will be a massive increase in workload for planners. No change made. Requirement R4, Part 4.1.2 – The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. Requirement R4, Part 4.3.1, bullet 3 – The planner may reflect the effects of either generic or actual relay models. No change made. Requirement R8 – The SDT believes that 30 days should be adequate time to get the necessary agreements in place to make the Planning Assessment available. No change made.		
National Grid	No	R2.8.2We recommend this requirement be clarified with the following modification: The Corrective Action Plan shall:2.8.1. List System deficiencies and the associated actions needed to achieve required System performance. 2.8.2. Be reviewed in subsequent annual Planning Assessments for continued validity and implementation status of planned modifications to System Facilities and Operating Procedures.
Response: The proposed change of "identified" to "planned modifications to" does not change the proposed requirement or add clarity. No change made.		
Consolidated Edison Co. of NY, Inc.	No	Requirement R1.1.5: Delete "and Interchange." The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow

Organization	Yes / No	Question 1 Comment
		case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: Requirement R1, Part 1.5 does not require Interchange for economic purposes. The requirement is to represent "Known commitments". No change made.		
Nebraska Public Power District	No	The existing TPL-001 through TPL-004 Standards and Requirements are clear and concise. The new merged TPL-001-1 Standard and Requirements is no longer clear and concise. Further, the modification made to allow an SPS to trip a remote generator for an N-1 (TPL-002) type of event is a degradation of system reliability. Transmission system facilities should be added to maintain stability for a new generator interconnection for any N-1 Category B event. An SPS should not be relied upon for a Category B event, an SPS should only be allowed for Category C & D (TPL-003 & TPL-004) type events.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards. There is no restriction in the existing TPL-002-1 on a planner's ability to utilize an SPS to trip a remote generator for a Category B event and the SDT did not change this. No change made.		
Northeast Power Coordinating Council	No	The wording of Part 1.1.2, "known outages...with a duration of at least 6 months" should be revised to "...at least 1 year". Also for consideration is that "known outages...with a duration of at least 6 months" are dealt with in operational studies rather than planning studies. Any adverse impacts that these outages might have are mitigated by operational decisions rather than planning decisions within a 6 month horizon. Moving this requirement out of the TPL Standard to an operational standard should be considered. Make the wording consistent between 2.1 and 2.2 as it relates to qualified past studies. Specifically:Parts 2.1.2, 2.1.4, 2.1.5The language of requirements 2.1.4 and 2.4.3 allowing the performance of one or moresensitivities appears to be inconsistent with language in 2.7.2. 2.7.2 requires multiplesensitivities to determine if actions to resolve performance deficiencies are necessary.Will varying only one measurable quantity several times in multiple simulationssatisfy multiple sensitivity studies or just one sensitivity study? The numbers and types of required sensitivity studies is unclear, and subject to interpretation by PCs and TPs. The current wording in Part 2.1.5, "spare strategy", appears to be open-ended regarding the number of

Organization	Yes / No	Question 1 Comment
		permutations to be analyzed. It should be restricted to assessing only one piece of equipment being unavailable or outaged at a time. 2.1.5 should be consistent with R2 and 2.1 regarding the use of the terms assessment and studies. As with the preceding comment regarding Part 1.1.2, moving this requirement out of the TPL Standard and to an operational standard should be considered.It is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service before the application of category P0, P1 and P2 events. This last sentence states:"...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment." The wording in Part 2.2 "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with the similar statement in Part 2.1: "be supported by current annual studies or qualified past studies". Part 2.7.1 lists potential system actions to address System deficiencies. It is suggested that this list be moved to a guideline or white paper. The wording in Part 8.1 needs to be amended to restrict comments to the most recent assessment only. Contingencies on back to back HVDC installations are not mentioned in the standard. The treatment of combined cycle facilities (all units in outage?) needs to be clarified, as well as Footnote 7 of Table 1 requiring clarification. In Table 1, Event 1 of Category P2 and related Footnote 7 are not clear because of the use of the word "possibly". If the intension is to simulate the line end opening condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote). From Table 1b: "Consequential Load Loss as well as generation loss is acceptable as a consequence of any event excluding P0." Firm Transmission Services Loss is also acceptable and should be added (particularly in P1 loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability).

Response: Requirement R1, Part 1.1.2 does not address the outages in the operational time frame. However, if a planner knows that a System component is going to be out of service for more than 6 months, the planner must model the component outage in the appropriate models and evaluate the System to ensure that the System meets the performance requirements of the standard. No change made.

Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to

Organization	Yes / No	Question 1 Comment
ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.1.4 and 2.4.3 each require two studies on sensitivity cases, but more studies can be performed by the planner. Requirement R2, Part 2.7.2 states that Corrective Action Plans are required (or rationale for why they are not needed) are required if performance deficiency exists in multiple sensitivity studies, not just one study. No change made. Requirement R2, Part 2.1.5 requires the study of each major Transmission equipment outage, consistent with spare equipment strategy, for System normal and P1 and P2 Contingencies. It does not require the study of P1 and P2 Contingencies with more than one major Transmission equipment, except for other equipment that are modeled out as "Known outages" consistent with Requirement R1, Part 1.1.2. No change made. Requirement R2, Part 2.1.5 is a planning requirement to ensure that an entity's spare equipment strategy is considered during the development of the Planning Assessment. The curtailment of Firm Transmission Service (FTS) for the situation outlined would be considered curtailing FTS for Normal System conditions and is not allowed. No change made. Requirement R2, Part 2.1 and 2.2 – The SDT left the requirement to conduct the annual study on one of the study years in the Long-Term Planning Horizon to ensure that the planner would conduct a new study annually to evaluate the System improvement needs in the Long-Term Planning Horizon. No change made. Requirement R2, Part 2.7.1 – The list represents examples, but not an exhaustive list of actions that could make up a Corrective Action Plan. No change made. Requirement R8, Part 8.1 - The SDT does not believe that a time limit for commenting on a Planning Assessment is required. Beyond responding to the comment, other actions by the planner are at the discretion of the planner. No change made. Table 1, P1 {back to back DC - The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made. Combined cycle generation outages are expected to be modeled in the manner that they would be tripped, per Requirement R3, Part 3.3.1 and Requirement R4, Part 4.3.1. Therefore, if the outage of one generator causes more generation to be lost (via the Protection System or other automatic controls are expected to disconnect), then, the entire amount of generation lost must be modeled for that specific contingency. No change made. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Top note 1b – The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's		

Organization	Yes / No	Question 1 Comment
concern. No change made.		
Ameren	No	There were a number of comments made on the previous draft of TPL-001-2 for which there were few, if any, changes made to the latest draft of the standard. Specifically:Requirement R1 does not address normal (pre-contingency) operating procedures or system configurations. Language should be added to the requirement (possibly as an additional Requirement R1.1.7) to include normal operating procedures or system configurations in place prior to any contingency occurring. Requirement R2.4.1, which addresses dynamic load modeling, has been a cause for concern because of the lack of guidance regarding reasonable induction motor representation as opposed to generic load models. While it is recognized that the effort to simulate the effects of induction motor loads is important, it is premature to include such modeling as part of the requirements for this standard. In addition, it appears that only the peak load model in R2.4.1 is required to represent expected dynamic behavior of Load. Such load models, if adopted should represent dynamic behavior of the load for all dynamic studies.
Response: The SDT posted a redline draft against the last posted draft and also posted a redline draft against the previous ballot draft. The SDT addressed many important issues that were raised during the first ballot. The SDT did not include all of the different procedures that are permitted. Normal operation procedures or system configuration may be utilized as long as they are consistent with the way the System would be operated and not inconsistent with the requirements within the standard. Requirement 2, Part 2.4.1 – One focus of dynamic Load model requirement in Part 2.4.1 is “considering the behavior of induction motor Load”. The areas of concern for induction motor Load are the Peak Load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at high Load levels with a high penetration of induction motor Loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor Load, for the other Load periods. Even though the standard doesn’t have the explicit requirement for other Load levels, Requirement R1 includes the statement “shall represent projected System conditions”, so the planner cannot ignore the dynamic behavior of the Load for those other Load periods. No change made.		
Western Area Power Administration	No	We concur that the standard is an improvement over previous drafts, but we vote "No" to the existing draft and request additional clarifications and/or modified language for a re-circulated vote prior to adoption. The following are areas where we suggest improvement or have questions:Please further define Consequential and/or Non-Consequential Load Loss: Does the Consequential Load Loss definition include underfrequency or undervoltage load shedding installed to protect transmission system reliability? Does the Consequential Load Loss definition include load tripped by a Special Protection System (SPS) or a

Organization	Yes / No	Question 1 Comment
		Remedial Action Scheme (RAS)? Either how underfrequency and undervoltage load shedding or how load shedding by a RAS relates to Consequential Load Loss should be clear in the Consequential and/or Non-Consequential Load Loss definition of the approved version of this NERC standard. Why is Near-Term Tranmission Planning Horizon deleted from the definitions of Terms Used in this Standard, yet it is used throughout the standard? This definition should remain. R1.1.5: How are "known commitments for Firm Transmission Service" to be modeled and tracked in power flow cases? Is it acceptable for Transmission Planners to simply assume what the ultimate sources and ultimate sinks are for each firm transmission service commitment or are Transmission Planners to know exactly which ultimate sources and ultimate sinks are associated with each commitment and to track each one accordingly in each power flow case?Assuming the intent here is reliability based and not marketing based, is the application of Firm Transmission intended to apply to reliability designated 'paths'? Most all Firm Transmission service contracts have caveats for unplanned interruption and such agreements should qualify as "re-dispatch" per Footnote 9? R2.1.5: If a group of utilities were to develop and manage among themselves a coordinated spare equipment program, such that the risk to any one of its participating entities of experiencing a significant unavailability for any major Transmission equipment that has a lead time of one year or more is deemed not significant, then would those utilities still have to do the studies required by R2.1.5 to evaluate the system impact of extended outages of such equipment?Scenario for Clarification: Short of spare equipment for items with a greater than 1 yr lead time, assessment studies are required to include sensitivities and operating plans for sustained loss of these equipment items, as a prior outage. For example, if an EHV facility is lost for more than 1 yr, and firm transmission interruption is not allowed, it appears the only compliant alternative (to a redundant facility) is a redispatch plan that is well documented and accepted by all stakeholders, per Footnote 9. R2.3: Is only the 5-year Near-Term Transmission Planning Horizon case required for the annual short-circuit analysis? R2.4.1: How is the dynamic modeling of induction motor Loads to be developed by the Transmission Planners? Is it acceptable for Transmission Planners to assume the same induction motor modeling as has generally been assumed and applied by most Transmission Planners throughout the Western Interconnection or will the induction motor modeling have to be based upon the type and amount of actual

Organization	Yes / No	Question 1 Comment
		induction motors installed in the system? R2.5: Does NERC have a particular technical rationale about what determines "proposed material generation additions or changes?" R2.6.2: Does NERC have a particular technical rationale about what determines "material changes?" R2.7.3: Please define "beyond the control" under Definition of Terms Used in Standard. This is an important concept. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If the stakeholder rate payers do not approve expenditures for facility improvements required to eliminate non-consequential load loss, is this beyond the control of the Transmission Planner? Rate payers should be able make the ultimate free market choice determination of risk versus cost associated with their reliability. Otherwise market interests (particularly generation) disproportionately pressure excessive reliability based improvements that must be borne by all rate payers. R3.3.1: Please define "relay loadability limit" under Definitions of Terms Used in Standard. This is an extremely important concept. This term has been used quite commonly for decades and is now used in this latest proposed standard. Without NERC definition, this term is highly debatable and should be eliminated. Scenario for Clarification: If PRC-023 is met whereby all "relay loadability limits" are set at least 150% of the highest thermal limiter (0.85 voltage and 30 lagging powerfactor) this sensitivity would justifiably not be needed so long as verification is shown that no element overloaded greater than 150%. R3.1 and R3.4: The interrelation between these two paragraphs needs additional clarification. R3.1 calls for verification via studies that the BES meets Table 1 performance criteria based on the contingency list resulting from R3.4. However, R3.4 states that the contingency list used to meet R3.1 only need include "Those planning events in Table 1, that are expected to produce more severe System impacts on.....the BES" and the associated "rationale" for those chosen contingencies. Is NERC suggesting that the studies do not need to include all contingencies based on Table 1, so long as ample "rationale" is provided? However, the Transmission Planner must provide studies to determine if every contingency of Table 1 meets performance requirements. How are the "more severe" contingencies determined if the Table 1 contingencies are not evaluated comprehensively? It seems R3.4 could be eliminated and the contingencies be based simply on Table 1. Please define "more severe", relative to less severe under Definitions of Terms Used in Standard, in an effort to help evaluate the suitability of a particular contingency for inclusion on this list. Looking at context, it appears that the purpose of this statement is to ensure that the worst contingencies are studied. Is the intent here simply to allow a given contingency to cover for a less severe or similar contingency and avoid duplicate simulations?

Organization	Yes / No	Question 1 Comment
		R3.4.1 and R4.4.1 Please include and define a reasonable number of contingent buses into adjacent systems that should be considered. No more than 2 are recommended for the standard. R3.5 and R4.5: How many of the "events in Table 1 that are expected to produce more severe system impacts" should the required evaluation identify and evaluate? To what extent should the evaluation focus on the "other" Extreme Events described under items 3.b and 2.f in Table 1, particularly if existing disturbance reports in the Western (or Eastern) Interconnection have recorded and evaluated the occurrence of particular events that have already created cascading? Because the requirement seems to involve a check for Cascading, perhaps some clarity could be provided with respect to the NERC definition of "Cascading." In particular, in the Cascading definition, how widespread is "widespread;" is the phrase "electric service interruption" only about the loss of firm load or could it also be only about the loss of firm generation or only about the loss of firm transmission service or is it about some combination of loss of firm load, loss of firm generation, and loss of firm transmission service; how large an area is meant by the expression "spreading beyond an area predetermined by studies" when the simulations that analyze the initiating Extreme Event will model the entire Western (or Eastern) Interconnection? So how does the study determine that the sequentially spreading service interruption has spread beyond the entire Western (or Eastern) Interconnection that is modeled in the simulation? Or is the term "area" meant to describe only that part of the Western (or Eastern) Interconnection that the Transmission Planner has evaluated for system impacts while ignoring impacts to the rest of the Interconnection? Table 1 - Planning Events, Steady State Only Note i: "The response of voltage sensitive Load that is disconnected from the System by end-user equipment associated with an event" seems to be included as items 2) and 3) under the Non-Consequential Load Loss definition. So, it seems acceptable to use this form of load loss to meet the stability performance requirements. However, the "Steady State Only" note i in Table 1 specifically does not allow its use to meet steady state performance requirements. Therefore, the "Steady State Only" note i in Table 1 should clarify why it seems acceptable to use it to meet stability performance requirements but not to meet steady state performance requirements. Table 1 - Planning Events, Category P2: Category P2 seems to include an unrelated mix of planning events ranging from a seemingly benign event (i.e., opening of a line section without a fault) to what would seem to be much more severe events (i.e., bus section fault or internal breaker fault). A clarification of why these planning events were lumped into the same Category P2 would be helpful to the Transmission Planner. Also, does the language in footnote 7 (i.e., "opening one end of a line section without a fault on a normally networked Transmission circuit ...") mean that P2-1 ("opening of a line section without a fault") should be

Organization	Yes / No	Question 1 Comment
		modeled as an open-ended line section? Table 1 - Planning Events, P2-2 (EHV) and P2-3 (EHV): For each of these planning events, its corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with each of the “No” boxes, similar to that allowed under the seemingly much less severe event P2-1 (“opening of a line section without a fault”). Otherwise, please explain why the seemingly much less severe P2 event (P2-1) has a footnote 12 exception for Non-Consequential Load Loss Allowed but the two seemingly more severe P2 events (P2-2 and P2-3) do not. Table 1 - Planning Events, P4-1 through P4-5 (EHV): For the stuck breaker planning events of P4-1 through P4-5 on the EHV system, their corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with their “No” box, similar to that allowed under the seemingly much less severe N 1 planning events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe stuck breaker events (P4-1 through P4-5) do not. Table 1 - Planning Events, P5-1 through P5-5 (EHV): For the relay failure planning events of P5-1 through P5-5 on the EHV system, their corresponding “Non-Consequential Load Loss Allowed” column should include a footnote 12 with their “No” box, similar to that allowed under the seemingly much less severe N 1 events (P1-1 through P1-5). Otherwise, please explain why the seemingly much less severe N 1 events (P1-1 through P1-5) have a footnote 12 exception for Non-Consequential Load Loss Allowed but the seemingly much more severe relay failure events (P5-1 through P5-5) do not.

Response: The definition of Consequential Load Loss does not include underfrequency or undervoltage load shedding, since this Load is not interrupted by the “Protection System operation designed to isolate the fault”. No change made.

The definition of Consequential Load Loss does not include Load tripped by a Special Protection System (SPS) or a Remedial Action Scheme (RAS), since this Load is not interrupted by the “Protection System operation designed to isolate the fault”. No change made.

The definition of Near-Term Transmission Planning Horizon is now an approved NERC Glossary Term. No change made.

Requirement R1, Part 1.1.5 (Known commitments for Firm Transmission Service and Interchange) is required to ensure that planners consider those transactions that have been committed to and meet the system performance requirements. “How” the planners account for these commitments should be developed by the planner in accordance to all of the regulatory and market rules that apply to them. No change made.

Requirement R2, Part 2.1.5 does not require a planner to study the unavailability of major long lead time equipment if the entity’s spare equipment strategy could

Organization	Yes / No	Question 1 Comment

not result in the unavailability of that equipment for one year or more. No change made.

Requirement R2, Part 2.3 requires the short circuit analysis only for the years of the Near-Term Transmission Planning Horizon. No change made.

RequirementR2, Part 2.4.1 – The SDT believes that the planner must consider the dynamic behavior of its System load and develop a representative model, however, the SDT should not dictate "how" the load should be modeled. No change made.

Requirement R2, Part 2.5 does not specify "how" an entity determines that "proposed material generation additions or changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made.

Requirement R2, Part 2.6.2 does not specify "how" an entity determines that "material changes" have occurred. It is up to each entity to develop its technical rationale for its determination. No change made.

Requirement R2, Part 2.7.3 has been included to account that certain Corrective Action Plans may not be able to be implemented due to circumstances that the planner cannot control. The SDT expects that these situations will be limited and that the impact to BES will be limited to interrupting Non-Consequential Load if the Contingency were to occur. Due to the wide variety of circumstances across North America, the SDT did not believe that it was appropriate to articulate the acceptable set of conditions. No change made.

Requirement R3, Part 3.3.1 utilizes the term "relay loadability limits" as it is utilized in the PRC standard. No change made.

Requirement R3, Parts 3.1 and 3.4 together require the planner to create a list of the "more severe" Contingencies, along with the rationale for "why" those Contingencies were selected, that will be simulated to ensure that the System meets the performance requirements. This language was included to be consistent with the existing TPL standards that do not require the planner to run simulations of all possible Contingencies. No change made.

Requirements R3, Part 3.4.1 and Requirement R4 Part 4.4.1 do not include "how" to define the Contingencies in adjacent systems that should be included since it will be variable based on the conditions of the System. It is the responsibility of the planners to coordinate the list of Contingencies to ensure BES reliability. No change made.

Requirement R3, Part 3.5 and Requirement R4 Part 4.5 require the planner to identify the "events in Table 1 that are expected to produce more severe system impacts". The number of "events" that should be included in the list are a "how" that the planner must determine. No change made.

Table 1, Extreme Events Steady State 3b and Stability 2f are included to ensure that the planner considers "operating experience" when determining the extent of Contingency analysis to conduct for the entity's Extreme Event simulations. The term "widespread" categorizes those events that are more far-reaching than the Local Area events identified in Extreme Events Steady State 2 a-e. No change made.

Table 1, Top note 'i' Steady State Only does not apply to Stability studies. Therefore, voltage sensitive Load disconnected by end-user equipment may be used during Stability simulations. The planner should not depend on this voltage sensitive Load being disconnected to meet the performance requirements (steady state after the system transient reaction ends) but this Load should be disconnected from the System for the Stability simulations to accurately represent how the

Organization	Yes / No	Question 1 Comment
System will respond. No change made. Table 1, P2 contains single Contingency events that have the same performance requirements. No change made. Table 1, P2-1 covers the opening of line section without a fault and Footnote 7 clarifies that the line section may be energized from one end and still serving Load. The expectation is that both situations are evaluated when appropriate. No change made. Table 1 P2-2 (EHV) and P2-3 (EHV) do not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these single Contingencies without Non-Consequential Load Loss. No change made. Table 1, P4-1 through P4-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made. Table 1, P5-1 through P5-5 (EHV) does not allow the exception allowed by Footnote 12. The SDT believes that the EHV system should be planned to handle these Contingencies without Non-Consequential Load Loss. No change made.		
Progress Energy		First, Progress Energy ("PE") notes that many changes to the Requirements language have been appropriate or have improved upon the language of the previous drafts, and PE commends the SDT in this. PE does have concerns, however, with the language in R8 and its corresponding Measure M8, and therefore must select 'no' for Q1 and provide comments. PE disagrees with the language of R8 primarily to the extent that the use of the verb “distribute” with respect to communicating Planning Assessments leads the reader to M8, which lacks language that would provide for the optimal correlation with R8. Regarding the M8 language, PE feels that the term “demonstration of a public posting” is a valid action in demonstrating compliance with R8 and thus should be more clearly described as one of several acceptable methods of distributing Planning Assessments. In addition, given the appropriate concern that NERC and FERC have recently raised regarding Cyber threats and the need for additional Cyber Security measures, PE feels that the public posting language should contain a qualification regarding the security of CEII information. PE thus recommends that an appropriate phrase to use would be “demonstration of a secure public posting”, thereby making clear that a public posting would not be a website accessible to just anyone due to CEII concerns.
Response: Requirement R8 - The SDT agrees that posting is an acceptable method of distributing but the intent of the standard requirement is to ensure that affected parties obtain the Planning Assessment. Measure M8 clarifies that posting is acceptable but not the only way to meet the requirement. While the SDT recognizes that certain planning information is covered by CEII requirements, the responsibility to protect that information already resides with the entity and is therefore not needed within this standard. No change made.		

Organization	Yes / No	Question 1 Comment
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
MRO's NERC Standards Review Forum	Yes	
BC Hydro	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Arizona Public Service Company	Yes	
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Muscatine Power and Water	Yes	
ITC	Yes	
Tri-State Generation and Transmission Assn., Inc.	Yes	In general, revisions are editorial and seem to have improved the overall document.

Organization	Yes / No	Question 1 Comment
Pepco Holdings Inc	Yes	Pepco Holdings Inc supports the proposed revisions.
Puget Sound Energy, Inc.	Yes	We Appreciate SDTs efforts in bringing clarity to the TPL standards.
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
American Transmission Company, LLC	Yes	
TVA TP&C	Yes	
Xcel Energy	Yes	
MISO	Yes	
Consumers Energy	Ballot Comment	We agree with the comments of MISO.
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

2. **The SDT has made revisions to the VRF and VSL of TPL-001-2 which will be part of a non-binding poll with this posting based on industry comments and the Quality Review. Do you agree with these changes? If you do not support these changes or you agree in general but feel that alternative language would be more appropriate, please provide specific suggestions in your comments.**

Summary Consideration: Comments received were predominantly about individual assessments of whether a VRF or VSL had been assigned correctly and some pointed out what they thought were incorrect interpretations of established guidelines by the SDT. The SDT followed guidelines established by FERC and NERC in these areas and therefore no changes were made in this regard.

In two particular instances, inconsistencies between wording in the requirement and VSL were pointed out and the SDT made the following changes due to those comments:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR, The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners.

	it was more than 30 days but less than or equal to 40 days following the request	it was more than 40 days but less than or equal to 50 days following the request.	it was more than 50 days but less than or equal to 60 days following the request.	OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.

Organization	Yes / No	Question 2 Comment
Consolidated Edison Co. of New York	Ballot Comment	Requirement R1.1.5: Delete “and Interchange.” The inclusion of other than Firm transactions (e.g. economic transactions in Interchange) in a base power flow case utilized for planning/designing the interconnected system blurs the boundary between reliability issues and purely economic issues. Reliability issues are issues that a Transmission Owner (TO) must address for the purpose of meeting its load demand, and are defined by the application of well established reliability standards and criteria that are based on the electrical characteristics of the interconnected system, but without economic considerations. Instead, economic transactions are types of transactions that a TO may enter into once its load obligations are met, and are

Organization	Yes / No	Question 2 Comment
		evaluated based on economic parameters that are markedly different from the aforementioned reliability criteria (e.g. congestion costs). Modeling all types of transactions in a power flow case without distinction detracts from the accuracy and validity of either assessment (reliability and economic).
Response: The SDT selected Known commitments for Firm Transmission Service and Interchange to separate the planning requirements of commitments from the economic transactions. No change made.		
San Diego Gas & Electric	Ballot Comment	The clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT believes that there is much less ambiguity in the proposed standard than the existing standards, based on feedback from previous postings. . No change made.		
Alberta Electric System Operator	Ballot Comment	The AESO casts an abstain vote as the VSLs and VRFs in Alberta are established by provincial authorities.
Response: Thank you for your response.		
Western Electricity Coordinating Council	Ballot Comment	I'm not certain that I agree with changing the VRF for R2 from Medium to High. I understand that it is accordance with the VRF guidelines, but I guess I disagree with the guidelines. I don't believe that any requirement with a planning time frame, if violated, could directly cause or contribute to bulk electric system instability, separation, or a cascading sequence of failures, or could place the bulk electric system at an unacceptable risk of instability, separation, or cascading failures, or could hinder restoration to a normal condition.
Response: The SDT is required to follow the VRF guidelines established by FERC, which apply to both operations and planning on equal footing. No change made.		
Florida Municipal Power Agency	Ballot Comment	FMPA has minor comments to help improve the clarity of the standard. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures.

Organization	Yes / No	Question 2 Comment
		R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Keys Energy Services City of Green Cove Springs	Ballot Comment	R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request? Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)
Response: Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made. Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made. Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.		
City of Austin dba Austin Energy	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote "b" regarding the planned or controlled interruption of electric supply for an N-1 event. In our view, a Registered Entity's Board of Directors, local public utility commission or customers should determine the acceptable level of service and the associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. Additionally, with respect to R2 (2.5), the value of annually assessing system stability for years 6-10 is

Organization	Yes / No	Question 2 Comment
		questionable. The requirement for stability assessment in years 6-10 should be limited to new generation interconnections or planned major transmission system improvements with regional impact. The standard should clarify the "material changes" that would necessitate stability planning assessments and documentation. Finally, The R8 requirement to distribute all Planning Assessment results to adjacent Planning Coordinators and Transmission Planners is excessive and cumbersome. Regarding R8, we suggest the following language: "Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and Transmission Planners in accordance with the requirements of the applicable Reliability Coordinator. Any Registered Entity with a reliability-related need may submit a written request for the Planning Assessment results and the Transmission Planner or Planning Coordinator shall provide the latest Planning Assessment results within 30 days of such request."
Response: Footnotes 12 and 9 were translated from the BOT approved language from TPL-002-1, Footnote ‘b’. No change made. For Requirement R2, Part 2.5, the SDT believes it is important to evaluate Stability when the planners are evaluating new generation additions or changes which can be more than 5 years in the future, as required in NERC Standard FAC-001-0. 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. No change made. For Requirement R8, the SDT disagrees that the requirement is excessive and cumbersome and did not make the suggested change. In addition, the proposed language would place requirements on the Reliability Coordinators, who are not included in the Applicability for this standard, and they should not be involved in determining the extent of the distribution of the Planning Assessments.		
Southwest Power Pool Regional Entity	Ballot Comment	I'm voting affirmative, but I'd prefer to avoid having VSLs where the only choice is Severe. I'd like to see either some gradation or we should use a different term to clarify that the requirement is either met or not (binary) instead of Severe VSL.
Response: The SDT is required to follow the guidelines established by NERC and FERC. No change made. No change made.		
Arizona Public Service Co.	Ballot Comment	While AZPS generally supports this standard, AZPS cannot support the violation severity levels that are proposed in the recirculation ballot. AZPS believes the time frames set forth in the proposed security levels are unreasonably short (10 days) and should be extended to 30 days between each elevation in severity level. For these reasons, AZPS has changed its vote to “negative.”

Organization	Yes / No	Question 2 Comment
Response: The SDT has followed the accepted guidelines for timeframes in the proposed VSLs. The SDT is required to follow the guidelines established by NERC and FERC. . No change made.		
Balancing Authority of Northern California NCR11118	Ballot Comment	SMUD believes believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: The SDT is required to follow the VRF guidelines established by FERC,.. No change made.		
Black Hills Corp	Ballot Comment	Black Hills is voting against the proposed VRF/VSL's based on the fact that the VRF for R2 was changed from Medium to High without any explanation.
Deseret Power	Ballot Comment	R2 was moved from medium to high without reason. Since it is long term it should remain medium.
California ISO	Ballot Comment	The VRF for Requirement R2 was changed from Medium to High without explanation. The other VRF's for assessment requirements continue to have a Medium VRF designation, and for consistency it would be appropriate for Requirement R2 to continue to have a Medium VRF designation.
Bonneville Power Administration	No	The VRF for R2 was changed from Medium to High without any explanation. Since the time horizon for R2 is Long Term Planning, BPA believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Arizona Public Service Company	No	With regards to R2, it appears that the VRF has changed from Medium to High without any justification; and with the time horizon of long term planning, AZPS believes there is no justification for changing it from Medium to High.
Idaho Power Company	Ballot Comment	The VRF for R2 was changed from Medium to High without any explanation. The time horizon for R2 is Long Term Planning and the Idaho Power believes that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Tucson Electric Power Co.	Ballot	This recommendation is based on the fact that the VRF for R2 was changed from Medium to High without any

Organization	Yes / No	Question 2 Comment
	Comment	explanation. The time horizon for R2 is Long Term Planning and it is believed that the VRF should be Medium, as are the VRFs for the other requirements related to conducting the assessments, rather than High.
Response: In the comment form for this posting, the SDT did address this issue as shown below: R2 – The VRF has been changed to High to reflect the importance of the Planning Assessment and to meet the latest guidelines. No change made.		
MidAmerican Energy Co.	Ballot Comment	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: In assigning the VRF for Requirement R8, the SDT is required to follow the guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes that it is important to continue with the approval of this standard. If FERC directs changes based on TPL-002-1, Footnote 'b', they will be addressed with this project.		
Hydro One Networks, Inc.	Ballot	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several

Organization	Yes / No	Question 2 Comment
	Comment	important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: Please see responses to on-line comments.		
Platte River Power Authority	Ballot Comment	VRF for R2 should be changed back to Medium. VRF for R8 should be changed back to Low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. . No change made.		
American Municipal Power	Ballot Comment	The VSLs appear to have a very low threshold for a SEVERE violation of the individual standard requirements for a planning standard. Please consider the impact of having arbitrarily low thresholds for SEVERE violations. The way the VSLs are set now, an honest interpretation or a small administrative mistake could result in a very high dollar penalty and would be construed as having a high correlation with causing a cascading outage by the media. I think we all just want the appropriate fines or sanctions for a violation and to have minimal fines or sanctions for accidental interpretations or menial paperwork based violations. Please consider another metric or raising the current thresholds.
Response: The SDT is required to follow the VSL guidelines established by NERC and FERC, which apply to both operations and planning on equal footing. No change made.VSL		
Florida Municipal Power Pool	Ballot Comment	A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal? B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady

<table>
<tr><th>Organization</th><th>Yes / No</th><th>Question 2 Comment</th></tr>
<tr><td></td><td></td><td>state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?

C. R7 is not needed and administrative in nature. Instead is should say that an entity can use as evidence another entity's study, but not in the requirement and rather in the measures.

D. R8 is ambiguous, does the requirement require submitting the Planning Assessment only after receiving a written request, or automatic distribution to neighboring PCs and TPs without a written request, and to others with a reliability related need following a written request?

E. Table 1, under first heading of "Steady State and Stability", bullet c should be removed since it is duplicative of the standard, and not entirely consistent with the standard (e.g., open to interpretation whereas the standard better clarifies how to study protection system operation)</td></tr>
<tr><td colspan="3">Response: Requirement R2, Part 2.1.5 ensures BES reliability by requiring the planner to assess the system for long lead time items based on the entities' spare equipment strategy. The footnotes in Table 1 clearly define the way transformers are evaluated. No change made.

Table 1, Steady State and Stability, Item I does not restrict the use of UVLS since it only addresses equipment disconnected by end-user equipment. No change made.

Requirement R7 ensures that there are no gaps between Transmission Planners or the Planning Coordinators that may cause reliability concerns. No change made.

Requirement R8 requires the automatic distribution to neighboring Planning Coordinators and Transmission Planners without a written request and to others with a reliability related need following a written request. The SDT believes this is an important consideration and not ambiguous. No change made.

Table 1, Bullet c under first heading, is not in conflict with the requirements. The SDT decided to include additional details in Table 1 so that it would have the basic information necessary for the planner to develop their simulations for their studies without always referring back to the requirements language. No change made.</td></tr>
<tr><td>MRO's NERC Standards Review Forum</td><td>No</td><td>The NSRF recommends that the VRF for Requirement 8 remain “Low”, rather than be changed to “Medium”. We do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.</td></tr>
</table>

Organization	Yes / No	Question 2 Comment
Minnkota Power Coop. Inc.	Ballot Comment	MPC echoes the comments of the MRO NSRS/F
Lincoln Electric System	Ballot Comment	Refer to comments submitted by the MRO NERC Standards Review Subcommittee.
Response: The SDT is required to follow the guidelines established by NERC and FERC.. No change made.		
Tri-State Generation and Transmission Assn., Inc.	No	Many of the sub-requirements of R2 do not warrant high risk VRFs, yet violation of any R2 sub-requirement would result in a "High Risk Factor" violation assessment. We believe that having so many sub-requirements can result in inaccurate overall severity classification. For example, skipping one study defined in R2.1.2 (Planning Assessments) for a particular time frame or load level would probably not result in a direct actual degradation in system performance, but would still result in a High Violation Risk Factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC, which apply to both operations and planning on equal footing.. No change made.		
Muscatine Power and Water	No	MP&W would like to recommend that the VRF for Requirement 8 remain "Low", rather than "Medium." It is our belief that there is not a significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. This is more administrative in nature. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. Additionally, entities with a reliability-related need for Planning Assessment information generally have the ability to perform their own independent planning assessment of adjacent systems or other areas of interest.
American Transmission Company, LLC	No	ATC recommends that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium". ATC does not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entities or a documented response to Planning Assessment comments is not provided within 90 days of a request. The findings in an assessment report are not urgent, but address system needs that will emerge over years in the future. In addition, entities with a reliability related need for Planning Assessment information generally have the means to make their own independent planning assessment of adjacent systems or other areas of interest.

Organization	Yes / No	Question 2 Comment
Electric Reliability Council of Texas, Inc.	No	ERCOT ISO believes that the VRF for R8 should be "low". The distribution of the Planning Assessment is administrative in nature, the failure to distribute the Planning Assessment does not necessarily equate to not communicating the content of the assessment, and the consequence of not distributing the Planning Assessment does not immediately impact the reliability of the BES; thus it does not warrant a 'Medium' risk factor.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
ReliabilityFirst	No	ReliabilityFirst generally agrees with the Violation Risk Factors (VRFs) but disagrees with the Violation Severity Levels (VSLs) for the following reasons:1. VSL for R1a. Under the last "Severe" VSL, the word "latest" should be removed to be consistent with the language in Requirement 1. This is a violation of the FERC Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement"2. VSLs for R2a. To be consistent with the language in Requirement 2, suggest modifying the last "Severe" VSL to state "The responsible entity failed to prepare an annual Planning Assessment of its portion of the BES" 3. VSLs for R3a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement. (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R3, Part 3.3.") 4. VSL's for R4a. Under the last VSL under the "High" category, the word "perform" should be replaced with "simulate" to be consistent with the requirement (e.g. "The responsible entity did not simulate Contingency analysis as described in Requirement R4, Part 4.3."). 5. VSLs for R6a. To be consistent with the language in Requirement 6, suggest modifying the "Severe" VSL to state "The responsible entity failed to define and document, within their Planning Assessment, the criteria or methodology used in the analysis to identify System instability for conditions, as described in Requirement R6." 6. VSLs for R7a. Suggest adding the following language to the end of the "Severe" VSL; "for the Planning Assessment", to be consistent with the requirement. 7. VSL for R8a. Under all four categories of VSLs, any reference to "Planning Assessment" should be changed to "Planning Assessment results" to be consistent with the language in Requirement 8 (or more appropriately, the term "results" should be removed from Requirement 8). This is a violation of the FERC

Organization	Yes / No	Question 2 Comment
		Guideline 3: "Violation Severity Level Assignment Should Be Consistent with the Corresponding Requirement" b. Under the "Lower" VSL, it is unclear why there is a 30 day timeframe for the first VSL, while the "Moderate", and "High" VSLs have a 10 day timeframe. Based on FERC recommendations, suggest making the timeframe for all four VSL s, 10 day increments. c. VSLs need to be developed to deal with a violation of Part 8.1 (i.e. the PC or TP failed to provide a documented response to that recipient within 90 calendar days of receipt of those comments)

Response: 1. The SDT has corrected the language used as shown:

R1. VSL – Severe (third part): The responsible entity's System model did not use ~~the latest~~ data consistent with ~~the data~~that provided in accordance with the MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.

2. The SDT believes that the wording shown must be taken in context and thus is clear. No change made.

3. & 4. The SDT believes the word 'perform' is consistent with the language used in the requirement. No change made.

5. The SDT sees the suggested change as unecessary and not providing any additional clarity as it is clear that the analysis is part of the Planning Assessment. No change made.

6. The entire standard is about the Planning Assessment and the SDT believes that this is clear in the language used. No change made.

7. The SDT has made the suggested change as shown below:

R8 VSL	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 120 days but less than or equal to 130 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 130 days but less than or equal to 140 days following its completion. OR,	The responsible entity distributed its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners but it was more than 140 days following its completion. OR

Organization	Yes / No	Question 2 Comment			
	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request.	The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 50 days but less than or equal to 60 days following the request.	The responsible entity did not distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners. OR The responsible entity distributed its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 60 days following the request. OR The responsible entity did not distribute its Planning Assessment results to functional entities having a reliability related need who requested the Planning Assessment in writing.	

7b. The 30 days shown is according to the established guidelines as are the 10 day increments that follow. The SDT is required to follow the guidelines established by NERC and FERC. No change made.e.

7c. VSLs have been developed with regard to Requirement R8, part 8.1 and were shown in the posted version. No change made.

<table>
<tr><th>Organization</th><th>Yes / No</th><th>Question 2 Comment</th></tr>
<tr><td>ITC</td><td>No</td><td>ITC recommends revising R8 VSLs as follows:Lower VSLThe responsible entity distributed its Planning Assessment to known adjacent Planning Coordinators and known adjacent Transmission Planners but it was more than 90 days but less than or equal to 120 days following its completion. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 30 days but less than or equal to 40 days following the request.

Moderate VSLsThe responsible entity distributed its Planning Assessment more than 30days but less than 60 days after subsequent requests by adjacent Planning Coordinators or adjacent Transmission Planners who were not sent copies upon completion of the Planning Assessment. OR, The responsible entity distributed its Planning Assessment to functional entities having a reliability related need who requested the Planning Assessment in writing but it was more than 40 days but less than or equal to 50 days following the request

High VSLs - eliminate this section. i.e., no high VSLs only lower,moderate and severe

Severe VSLsThe responsible entity distributed its Planning Assessment to functional entities having a reliability related need, adjacent Transmission Planners and adjacent Planning coordinators who requested the Planning Assessment in writing but it was more than 60 days following the request.</td></tr>
<tr><td colspan="3">Response: 1. The suggested wording change is not consistent with the language used in the Requirement. Furthermore, the SDT does not believe that the word ‘known’ is necessary in this regard. No change made.

2. The suggested wording is not consistent with the language used in the requirement. Furthermore, the increment suggested would violate established guidelines. The SDT is required to follow the VSL guidelines established by FERC. No change made.

3. When dealing with incremental times in VSLs, the established guidelines indicate that all 4 types of VSL should be utilized. No change made.

4. The SDT believes the suggested change makes the VSL less clear. No change made.</td></tr>
<tr><td>Manitoba Hydro</td><td>No</td><td>-The language “latest data” is used in the Severe VSL for R1, however “latest” was removed from R1 and M1. “Latest” should also be removed from the Severe VSL for consistency.-What is the rationale for changing the preparation of the Planning</td></tr>
<tr><td colspan="3">Response: The SDT has corrected the language used as shown:

R1. VSL – Severe (third part): The responsible entity’s System model did not use <s>the latest</s> data consistent with <s>the data</s><u>that</u> provided in accordance with the</td></tr>
</table>

Organization	Yes / No	Question 2 Comment
MOD-010 and MOD-012 standards and other sources, including items represented in the Corrective Action Plan.		
National Grid	No	R 2.0 We recommend that the VRF for this Planning Requirement remain at "Medium". The risks associated with Planning Requirements have a longer time horizon for corrective action than, for example, those risks associated with much shorter Operational time frames.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
Independent Electricity System Operator	No	See our response to Q1.
Response: See response to Q1.		
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
MISO	No	Regarding Requirement 8, we do not believe that there is significant risk to the reliability of the BES if an annual Planning Assessment is not distributed to another entity or if a documented response to Planning Assessment comments is not provided within 90 days of a request. Requirement 8 is an administrative requirement that adds little to improve reliability. We recommend that the VRF for Requirement 8 remain "Low", rather than be changed to "Medium".
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
New York Independent System Operator	No	Requirement 8 is an administrative burden that adds no value to reliability. Comments have been provided on several past drafts highlighting this effect. The revisions made to the VRF and VSL for Requirement 8 further exacerbate this burden. One could conclude from observation of the VSLs and VRFs, that Requirement 8 was the most important requirement of TPL-001-1.Many Planning Coordinators and Transmission Planners have stakeholder processes that govern participation and notification. Further, FERC Order 890 requires stakeholder participation and transparent processes.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC.. No change made.		

Organization	Yes / No	Question 2 Comment
Ameren	No	The VRF for Requirement R8 should remain Low. There is no significant risk to the reliability of the BES if a Planning Assessment is not distributed to another entity, or if a documented response is not provided within 90 days of a request. The assignment of some VRFs are inconsistent with the importance of the requirements. R2 requires the development of an assessment and it is determined to have a high VRF. However, R3 and R4 require that studies be performed and these studies are determined to have a medium VRF. Performing the studies is essential to developing an assessment and more important to maintaining reliability. If the VRFs for R3 and R4 are correct, then the VRF for R2 should be no higher than medium. The VRF for R5 to develop a steady-state voltage criteria is determined to be medium. However, the VRF for R6 to develop instability criteria is determined to be low. If the VRF for R6 is correct, then the VRF for R5 should also be low.
Response: The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made. The SDT agrees that studies are essential to the Planning Assessment but believes that the Planning Assessments are more than just the studies. For example, under the correct set of circumstances, an entity can use past studies in their Planning Assessment. Therefore, the SDT believes that the VRFs assigned are correct and in adherence with established guidelines. No change made. The SDT believes that having the criteria (Requirement R5) is more important for the reliability of the BES than documenting the methodology (Requirement R6). No change made.		
SERC Planning Standards Subcommittee	Yes	
SPP Reliability Standards Development Team	Yes	
Entergy Services	Yes	
Imperial Irrigation District	Yes	
Progress Energy	Yes	

Organization	Yes / No	Question 2 Comment
American Electric Power	Yes	
Duke Energy	Yes	
Transmission Strategies, LLC	Yes	
NIPSCO	Yes	
Puget Sound Energy, Inc.	Yes	
South Carolina Electric and Gas	Yes	
Georgia Transmission Corporation	Yes	
United Illuminating	Yes	
TVA TP&C	Yes	
ISO New England Inc.	Yes	
GDS Associates, Inc.	Yes	Agree in general.
Pepco Holdings Inc	Yes	
Northeast Utilities	Yes	
Oncor Electric Delivery Company LLC	Yes	
Response: Thank you for your support.		

3. **If you have any other comments on this Standard that you have not already provided in response to the prior questions, please provide them here.**

Summary Consideration: Several commenters stated that the SDT failed to address significant concerns and that only minor changes were made from the prior draft. The SDT believes that some stakeholders based their review on a red-line document of the TPL standard which only describes changes made following the Quality Review (QR) team review of the standard; shown as a red-line document http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted and communicated after the start of the last comment period. A number of changes were made in response to industry feedback prior to the latest ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf.

A number of commenters indicated they cast a negative vote and recommended the SDT delay further work on TPL-001-2 pending FERC's ruling on the revised Footnote 'b' to Table 1 found in the existing TPL standards. The SDT believes concerns in process efficiency related to this project and FERC's on-going review of the revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that an entity's vote should be based on the technical merits of the standard. The SDT has taken care to ensure footnotes 9 and 12 in combination are written consistently with footnote 'b'. The SDT encourages that any negative ballot based solely on FERC's pending ruling on footnote "b" be revisited.

Some commenters stated they find the new standard to be poorly organized and too prescriptively written and that the existing standards are preferred over the proposed TPL-001-2. The SDT and others in industry, as evidenced by the 74% ballot approval, hold a different opinion in regard to the standard. The SDT believes the comments of one stakeholder well articulate its view of the standard: "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace." The SDT believes many important improvements in transmission planning are driven by the proposed TPL-001-2 that will further improve reliability of the Bulk Electric System.

A few commenters questioned the term "non-redundant relay" as used in planning event P5 and asked the SDT to clarify a distinction between a "back-up relay" and a "redundant relay" and proposed the SDT provide a definition for the term "non-redundant". The SDT clarifies that redundant means 'duplicate capability resulting in the same outcome.' A redundant relay is not the same as back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition.

Several commenters noted that the standard makes use of new capitalized "defined" terms, yet the definitions proposed in previous drafts were removed from the most recent draft of TPL-001-2. The SDT clarified that two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10, titled "FAC Order 729". The two definitions, "Near-Term Transmission Planning Horizon" and "Year One" were approved by the NERC Board of Trustees on January 24, 2011.

Some commenters indicated that the standard' Implementation Plan should be extended to permit a full 5-years implementation of any Corrective Action Plans required due to short circuit studies. The commenters indicate that these studies are not presently covered by a NERC Reliability Standard and they see this as a significant "raising of the bar" as characterized by other new requirements. The SDT clarified that while a short circuit study requirement is new to mandatory enforceable standards, the SDT does not believe the short circuit study requirements present a significant "raising of the bar" for industry and that good utility short circuit practices are already in place to ensure safe operation of equipment. No extension in the Implementation Plan was made in regard to short circuit studies.

Several commenters stated an opinion that Requirement R1, Part 1.1.2 indicating the models maintained by the Transmission Planners should reflect "known outages … with a duration of at least 6 months", are more appropriately dealt with in the operational studies rather than planning studies and that the item should be removed from the standard. The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for long durations of time one or more years in the future and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The SDT retained the requirement in the standard.

A number of commenters stated that they believed that there was an inconsistency between Requirement R2, Parts 2.1 and 2.2, since qualified past studies were not allowed for the Long-Term Transmission Planning Horizon case. The SDT clarifies that the requirement to conduct a current annual study for one of the study years in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified past studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon.

Several commenters stated that they believed that Requirement R2, Part 2.1.5 was ambiguous since it was not clear that the planner did not have to include multiple outages of long lead time components simultaneously. The SDT explained that Requirement R2, Part 2.1.5 does not require simultaneous outages of multiple long lead time components.

Some commenters expressed concerns with Requirement R2, Part 2.4.1 since they were concerned with the ability of planners to adequately model the dynamic behavior of Load. The SDT explained that the "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific.

The SDT appreciates the concern raised by multiple commenters in regard to the inclusion of the 2nd bulleted item of Requirement R3, Part 3.3.1 that states the steady-state Contingency analysis should include subsequent "Tripping of

Transmission elements where relay loadability limits are exceeded". The commenters believe this concern is addressed by PRC-023 and should be removed from the standard. The SDT believes the item is warranted and that TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach.

A number of commenters expressed concern that Requirement R7 was administrative and was not required. The SDT explained that it believes that the requirement is necessary to ensure that there are no gaps created between the Transmission Planners and the Planning Coordinators when they determine their individual responsibilities.

Several commenters stated that they had concerns with Requirement R8. These concerns are that the requirements create excessive work and should include time limits on requesting the Planning Assessment, are ambiguous, and should include the ability to post the Planning Assessment. The SDT explained that the requirements are only to distribute the Planning Assessment, which should not require a large amount of work, and the requirements are clear that the planners must distribute to adjacent Transmission Planners and Planning Coordinators and others with a reliability need. The SDT further explained that posting the Planning Assessment could meet the requirement to distribute.

Several commenters stated that they believed that Table 1, P2-1 was inconsistent with Footnote 7. The SDT explained that Footnote 7 was included to clarify that "Opening a line section without a fault" could include, but does not always, creating a radial line section with Load and that the planner must evaluate this situation as a part of P2-1.

No requirements were changed as a result of comments received. However, two bulleted items were marked as bullets incorrectly and that formatting has been corrected.

3.1.1 Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made.

3.3.1.2 Tripping of Transmission elements where relay loadability limits are exceeded.

4.3.1.1 Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized.

4.3.1.2 Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made.

4.3.1.3 Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.

Organization	Yes/ No	Question 3 Comment
James A. Maenner	Ballot Comment	The medium VRF for R8 should remain at low. Not sharing planning assessments with other entities within 90 days doesn't create a serious or imminent threat to the BES.
Response: The change to a Medium VRF resulted from the Quality Review (QR) conducted by the independent QR team prior to the last ballot. This requirement is seen as more than simply an administrative response to a request but rather a proactive step required of the applicable planner to share results of its system assessment which may include and reflect potential system impacts to neighboring systems. The SDT is required to follow the VRF guidelines established by NERC and FERC. No change made.		
San Diego Gas & Electric	Ballot Comment	Clarity of this standard is getting worse. Our earlier comments did not seem impacting. At this point, we believe the existing TPL-001-0.1, TPL-002-0a, TPL-003-0a and TPL-004-0 provide much better clarify for us to comply with the TPL standards.
Response: The SDT respectfully disagrees with your view. According to results of the last ballot, 74% of the ballot poolsupport the proposed standard. The SDT believes the standard clarifies a number of expectations and that appropriate changes have been made to further improve the future planning and review of the Bulk Electric System's ability to reliably serve users of the system. No change made.		
Western Electricity Coordinating Council	Ballot Comment	It is unknown at this time what the outcome of the FERC request for additional infomation related to footnote B will be, but if if results in changes to the language of footnote B, that may change our support for this standard.
Salt River Project	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In SRP's view, a Registered Entity's Board of Directors, state Utilities Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Snohomish County PUD No. 1	Ballot	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or

Organization	Yes/ No	Question 3 Comment
	Comment	controlled interruption of electric supply for an N-1 situation. In our view, a Registered Entity's Board of Directors, Utility Commission, and/or its customers should determine what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Public Utility District No. 1 of Chelan County	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Clark Public Utilities	Ballot Comment	Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, the utility's elected board of commissioners should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made.		
Imperial Irrigation District		Previous TPL Standard balloting included the FERC Order that clarified footnote 'b', regarding the planned or controlled interruption of electric supply for an N-1 situation. In our view, board of directors/Public Utility should have the determination what level of service is acceptable and with what associated cost. This view is captured in footnote #12 of Table 1 in the TPL Standard and will be crucial to maintaining an Affirmative vote. 1. R2 (2.5): The value of assessing system stability for years 6-10 is questionable. Stability studies should be conducted for new generation interconnections or for planned major transmission system improvements that have regional impact. 2. R8 requirement to distribute all Planning Assessment results to adjacent PCs and TPs are excessive and cumbersome. Regarding R8, IID suggest the following languages:Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators and adjacent Transmission Planners in accordance with the overseeing Reliability Coordinator requirements. Any functional entity that has a reliability related need and submits a written request for the Planning Assessment results, the Transmission Planner and Planning Coordinator shall provide the latest Planning Assessment

<table>
<tr><th>Organization</th><th>Yes/ No</th><th>Question 3 Comment</th></tr>
<tr><td></td><td></td><td>results within 30 days of such request.</td></tr>
<tr><td colspan="3">Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees and submitted for regulatory approval. No change made.

Regarding Requirement R2, Part 2.5, the SDT believes the requirement as written meets your perspective. For the long-term period, the stability assessment is only required to address "… the impact of proposed material generation additions or changes in that timeframe …". No change made.

Regarding Requirement R8, the SDT disagrees that the requirements for distributing assessment results should be based on requirements of the Reliability Coordinator. The Reliability Coordinator is primarily focused on real-time issues/concerns not planning horizon timeframes. The SDT does not see this requirement as overly burdensome as the results could be emailed to multiple entities in a single notification. Additionally, we do not see Requirement R8 as excessive as we believe it is important to communicate assessment results with others in industry whose systems for which they are responsible for may be impacted by the host analysis being communicated. No changes made.</td></tr>
<tr><td>Gainesville Regional Utilities</td><td>Ballot Comment</td><td>I do have one point of concern for your consideration; This standard does raise the bar in some areas, most notably for an entity the size of GVL it applies performance requirements for long lead equipment emergency replacement. For example if we don't have the ability to replace a transformer at Parker within a few months of failure, then we would have to demonstrate that we can meet many (but not all) of the same performance criteria without the transformer that we can with the transformer.</td></tr>
<tr><td colspan="3">Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. No change made.</td></tr>
<tr><td>Beaches Energy Services</td><td>Ballot Comment</td><td>My biggest concern is the spare transformer issue. Beaches Energy Services is fine because our Transmission Planner (FMPA) actually run the assessments proposed in the new standard and we have excess transformer capacity; but, I'm concerned for other small entities. Essentially, the requirement will likely be interpreted as requiring us to meet the loss of a Bulk Electric System transformer, plus another contingency (two contingencies) to the same performance criteria as a single contingency, if we don't have a spare. This seems discriminatory to small entities.</td></tr>
<tr><td colspan="3">Response: The commenter is referring to expectations stated in Requirement R2, Part 2.1.5 related to a spare equipment strategy regarding the potential unavailability of long lead time equipment that could be out of service for a year or more in the absence of a spare replacement. The SDT believes it has appropriately limited the analysis to address Planning Events P0, P1, and P2 as stated in Table 1. Any organization – large or small - meeting functional entity</td></tr>
</table>

Organization	Yes/ No	Question 3 Comment
registration obligations has the potential to impact the Bulk Electric System and their assessments must include appropriate spare equipment strategies. No change made.		
Hydro One Networks, Inc.	Ballot Comment	Hydro One Networks is casting a negative vote. Other than a few changes related to Footnotes 9 and 12 of Table 1 and VSLs, the other changes in the proposed draft are minor. The concerns of the industry on several important issues have not been sufficiently addressed in this draft. For detailed comments please refer to our submission through the on-line comment form.
Response: The SDT believes the commenter's response is based on their review of red-line document of the TPL standard which only describe changes made following the Quality Review (QR) team review of the standard which was conducted prior to the last ballot. That red-line was shown as http://www.nerc.com/docs/standards/sar/tpl-001-2_redline_to_last_posted_110415.pdf. A complete and thorough red-line of the TPL standard showing all changes made from the prior 3/01/10 ballot period to the version posted on the most recent ballot (concluded on 5/31/11) was posted during the last comment/ballot period. A number of changes were made in response to industry feedback prior to the last ballot. Those changes can be viewed at: http://www.nerc.com/docs/standards/sar/TPL-001-2_Redline_to_last_balloted.pdf. The SDT's response to input provided by the on-line comment form is addressed in responses to Q1 and Q2 above. No change made.		
Hydro-Quebec TransEnergie	Ballot Comment	These are the two major concerns : * In Table 1 footnote 3 : Again, the definition of EHV facilities shoud be changed to something like : 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. * In Table 1 b : "Consequential Load Loss as well as generation loss is acceptable as a a consequence of any event excluding P0". We should also add Firm Transmission Services Loss is also acceptable (particularly in P1 Loss of a single pole of a DC line for which the transfer is reduced accordingly to the remaining pole capability). "
Response: In regard to Table 1 footnote 3, the SDT respectfully disagrees and believes the footnote is clear in regards to what subset of Bulk Electric System Facilities are classified as EHV and that the remaining fall to HV Facilities. Anything not deemed Bulk Electric System by a Regional Entity is outside of the scope of footnote 3 and the footnote clarifies that Table 1 sometimes has unique performance requirements depending on the event studied. The SDT believes the categorization is correct. No change made. The SDT disagrees that Firm Transmission Service (FTS) may be interrupted for all events. The events where the interruption of FTS is not permitted are shown with a "No" in the column titled "Interruption of Firm Transmission Service Allowed", however, footnote 9 clarifies that interruption of Firm Transmission Service		

Organization	Yes/ No	Question 3 Comment
can be used as both a corrective action and system adjustment as permitted within Table 1. For the specific issue raised, loss of a single pole of a DC line, to the extent the availability of the DC pole is a condition of the transfer being viable, footnote 4 may also address the commenter's concern. No change made.		
Independent Electricity System Operator	Ballot Comment	IESO is generally supportive of the draft of TPL-001-2 as evidenced by our previous AFFIRMATIVE vote during the last ballot. Further, IESO also supported the revisions to Footnote 'b' to Table 1 of the TPL standards under Project 2010-11. That revision was balloted and approved by the ballot pool in February 2011 and filed with FERC for approval in March 2011. The revised footnote has been incorporated into the current draft of TPL-001-2 as Footnotes 9 and 12 but the Commission, by letter to NERC dated May 17, 2011, has requested NERC to provide supplemental information before the revised Footnote 'b' could be approved. In light of FERC's request and the uncertainty regarding the final provisions of these footnotes, coupled with the ongoing work on Project 2010-17 for the revision of the BES definition and development of an Exception Process and the impact that may have, we respectfully suggest that the drafting team delay further work on TPL-001-2 pending FERC's ruling on NERC's petition seeking approval of the transmission planning standards that contain the revised Footnote 'b' to Table 1.
Response: The SDT believes IESO's concerns in process efficiency related to this project and FERC's on-going review of the prior submittal of a revised footnote 'b' should not be the sole reason for a negative vote on the new proposed TPL standard and that IESO's vote should be based on the technical merits of the standard. The SDT encourages IESO to revisit its negative ballot position during the recirculation ballot. As stated in the comment provided, IESO finds footnotes 9 and 12 to be written consistently with footnote 'b' and if IESO supported footnote 'b', the SDT encourages continued support of the issue in the new proposed TPL-001-2 and doing so shows support of the standard on its technical merits. No change made.		
Lakeland Electric	Ballot Comment	LAK appreciates the hard work of the Standard Drafting team and applauds the significant improvement of clarity of the draft standard. FMPA believes we are almost there, but, there are a number of issues left to resolve. Issues that Cause FMPA to Recommend a Negative Vote A. Spare Equipment, R2.1.5 - The requirement reaches beyond the FERC directive. The directive was: "Accordingly, the Commission directs the ERO to modify the planning Reliability Standards to require the assessment of planned outages consistent with the entity's spare equipment strategy." So, the directive is only to address planned outage, not unplanned outages. Also note that the applicability to GSUs is ambiguous. "Transmission" is defined as: "An interconnected group of lines and associated equipment for the movement or transfer of electric energy between points of supply and points at which it is transformed for delivery to customers or is delivered to other electric systems." Is the "point of supply" the generator terminal, or the GSU high side terminal?

Organization	Yes/ No	Question 3 Comment
		B. Table 1, under first heading of "Steady State Only", bullet i is open to interpretation. Many utilities use steady state P-V analyses to study voltage stability and design UVLS systems in apart around those steady state analyses. Would this bullet essentially eliminate P-V and Q-V studies and the related use of UVLS?
Response: The SDT respectfully disagrees that the Commission directive regarding a spare equipment strategy is limited to planned outages. In Order 693, Par 1725, the Commission states in its discussion "Thus, 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." The SDT believes FERC clearly intended the spare equipment strategy to cover a catastrophic loss of such long lead-time equipment. Further, the SDT believes it has appropriately limited this review to a small subset of the overall Planning Events – P0, P1, and P2 and for a loss that would be sustained for a year or longer. No change made. The SDT refers the commenter to footnote 5 in regards to the applicability of GSU transformers. The "point of supply" is irrelevant in regards to planning a Transmission system for potential generation loss. The applicable generation is any unit deemed to be BES generation supply by the applicable regional entity. No change made. The SDT points out that Table 1 header note "i" applies to steady-state only and is intended to prevent any reduction in non-consequential Load due to what the planner believes to be sensitive Load loss that may drop out as voltage declines. It is the understanding of the SDT that most utilities only reflect or account for such reduction in Load in the transient timeframe and that planning decisions based on steady-state analysis would appropriately account for serving the non-consequential Load unless subject to interruption per that studied planning event. The bullet does not eliminate P-V or Q-V studies nor does it prohibit use of UVLS as a mitigating action where non-consequential load interruption is permitted. No change made.		
New Brunswick Power Transmission Corporation	Ballot Comment	Foot Note 12: Rather than requiring planning entities to have a open and transparent planning stakeholder process, which could require significant costs and administration, the foot note should focus on ensuring that affected loads/entities are aware of the possible risks of load loss and alternatives and provide for affected stakeholder feedback
Response: The SDT believes the open and transparent stakeholder process described by footnote 12 provides an efficient platform for which the affected end-users and other registered entities would be made aware of instances where non-consequential Load loss is being considered as a Corrective Action Plan and provides the best opportunity for feedback. The process envisioned is already in place in various areas across the various Interconnections in which the NERC Reliability Standards are enforceable. No change made.		
Powerex Corp.	Ballot Comment	Powerex has submitted a negative ballot for Draft #6 of Standard TPL-001 because Powerex has concerns regarding Footnotes 9 and 4 that need to be addressed. Details of our concerns are summarized below.

Organization	Yes/ No	Question 3 Comment
		Background: The work that transmission planners do to ensure Firm Transmission Service is tremendously important for the reliability of the Bulk Electric System and forms a key part of the foundation upon which system operators and energy market participants interact. As a Purchasing-Selling Entity, Powerex is primarily concerned about Footnote 9 that conditions when interruption of Firm Transmission Service may allowed. We believe that the goals of maintaining system reliability and enhancing market participation will both be best served if the conditions for interrupting Firm Transmission Service become clear and unambiguous in the TPL-001-2 Standard. In our experience, Transmission Providers have different interpretations of the TPL-001 Performance Table and because of latitude previously granted by Footnote B have different perspectives of when Interuptions of Firm Transfers is acceptable. Below we describe the two interpretations using the language of the proposed TPL-001 standard. Interpretation #1: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads and Firm Transmission Service indefinitely. o Typically this is achieved by assuming that the System Operators would, within a few minutes of the P1 Single Contingency, curtail all non-firm transmission service and then arm Special Protection Schemes that could result in Interruption of Firm Transmission Service or Non-Consequential Load Loss in the event of a P6 Multiple contingency. Interpretation #2: Following loss of the most critical transmission element under stressed conditions, the transmission provider plans to supply the forecast peak loads indefinitely but may curtail all Firm Transmission Service within 20 minutes if required. o Typically this occurs on systems where there are no Special Protection Schemes to address P6 Multiple contingencies, consequently, the transmission planners assume that curtailment of all non-firm AND as much Firm Transmission Service as required will occur within ~20 minutes of the P1 Single Contingency because the Operators must prepare their transmission system to withstand the next worst contingency. Currently, Purchasing-Selling Entities must plan for situations where they could see their Firm Transmission Service on certain paths curtailed within 20 minutes of a P1 contingency. The less stringent interpretation of the TPL-001 Performance Table that allowed a P1 contingency to change into a P6 contingency within the same operating hour, has resulted in situations where the Firm Transmission Service for inter-regional transfers face significantly greater risks of interruption than the Firm Transmission Service provided to local Load Serving Entities. Powerex recommends that the Standards Drafting Team revise TPL-001 such that all Transmission Planners will know that they should plan for Firm Transmission Service to be sustained indefinitely following P1 contingencies. Specific Comments on TPL-001-2: Footnote 9: Deviation from the Approved Footnote B Powerex believes that the Footnote B, as approved by the NERC Board of Trustees on February 17, 2011, is more stringent than the previous Footnote B and will have the effect of ensuring that Firm Transmission Service can be sustained indefinitely following P1 contingencies. The key difference of the proposed Footnote 9 is that it adds

Organization	Yes/ No	Question 3 Comment
		the phrase "as a System adjustment" to the approved version of Footnote B. We believe this addition would cause the practice of curtailing Firm Transmission Service within 20 minutes of P1 contingencies to continue. Consequently, we recommend that the proposed Footnote 9 maintain the approved wording as follows: Footnote 9: An objective of the planning process should be to minimize the likelihood and magnitude of interruption of Firm Transmission Service following Contingency events. Curtailment of Firm Transmission Service is allowed (deletion)[as] a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch.... For consistency, Table 1 should also be modified to remove the Footnote 9 reference from the Initial Condition Column for the P3-Multiple Contingency and P6 Multiple Contingency Categories. Footnote 9: Clarity on what is meant by "Resources obligated to re-dispatch" It is unclear to many parties what is meant by an obligation to re-dispatch. Some interpret this as a right to direct the Source to curtail energy scheduled on Firm Transmission Service. Our belief is that "an obligation to re-dispatch" should correspond to a formal agreement with a Generation Owner, located on the load side of a transmission constraint, to resupply the load that had been receiving energy from a remote source before the Firm Transmission Service was curtailed. Consequently, we recommend that Footnote 9 be revised as follows: Footnote 9: ..... a corrective action when achieved through the appropriate re-dispatch of resources obligated to re-dispatch [to ensure uninterrupted energy supply to the Load-Serving Entity(ies)], where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in any Non-Consequential Load Loss.... Footnote 4: Conditional Firm Transmission Service Footnote 4: "Curtailment of Conditional Firm Transmission Service is allowed when the conditions and/or events being studied formed the basis for the Conditional Firm Transmission Service." In a sense, offering conditional firm transmission service is analogous to selling land in a known flood plane - this can be a perfectly acceptable option provided all parties involved in current and future transactions can quantify the risks and manage them appropriately. There needs to be coordination between the planners, operators and marketers to ensure that the conditions that could lead to curtailment of Conditional Firm Transmission Service are understood and the associated risks properly managed. We are concerned that in the absence of coordination, specifically additional requirements included in the BAL and INT standards, energy that is scheduled on conditional firm could actually be marketed as firm and as a result the counterparties to some transactions may not be aware of the curtailment risks they could face.

Response: Footnote 9 - The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The key is that there must

Organization	Yes/ No	Question 3 Comment
be no loss of Load and the planner must be able to show that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. The commenter indicates an opinion that footnote 9 introduces a difference from the revised footnote 'b' because footnote 9 is applied to multiple Contingency planning events P3 and P6 as an intermediate step – system adjustment. However, the SDT believes that footnote 'b' is consistent as it does not explicitly distinguish between the two – corrective action or system adjustment following the single Contingency event that may precede a multiple Contingency event. No change made. Footnote 4 – The SDT agrees with the commenter that the specifics of Conditional Firm Transmission service including the potential/rights for curtailments need to be well understood by all parties involved but the SDT has not identified any BES reliability gaps. No change made.		
Tucson Electric Power Co.	Ballot Comment	The definition for Near Term Planning Horizon was deleted, but the formal term is used in other sections such as R2.2.1. There should be a linkage to MOD standard (e.g. 028, 029 & 030) definitions such as 13 months, etc.
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011.		
Western Area Power Administration	Ballot Comment	Standard is improved over previous drafts, but would like to see further changes. Please see suggestions and comments provided on the Official Comment Form.
Response: Please see the SDT's response to your suggestions in Question 1.		
SERC Planning Standards Subcommittee		R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are not required in the current version 0 standards. The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Response: Requirement R1 of the new TPL standard requires the Transmission Planner and Planning Coordinator to maintain System models within its		

Organization	Yes/ No	Question 3 Comment
respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were either discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
SPP Reliability Standards Development Team		A5 It would seem that 84 months wouldn't be universally attainable due to different system configurations, terrain, geography, and permitting issues that are required to complete a corrective action plan. In 2.4.1 we would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the answer is a very detailed representation of the load system then it may take a longer time to implement. In section 2.7 we would to see clarification on the sensitivity analysis. Is this in reference to seasonal models and differences in fuel availability? We need more detail on how this is to be done so that it won't be left up to interpretation. We would like for clarification of the planning assessment and who is performing which tasks. We would also like to utilize a regional assessment due to limited resources. Under which criteria should the assessment fall under the regional entity or the individual companies? In section 3.4.1 this type of coordination could be difficult due to other adjacent entities on different schedules and some possibly couldn't have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? PC's between regions are already coordinating for long term studies. Should this standard fall more on the back of the PC's rather than the TP Can we get a bright line definition of what apparent impedance swings means? R4.3.1 will the detailed amount of data then be incorporated back into the NERC modeling processes and create a more detailed model with better accuracy?

Organization	Yes/ No	Question 3 Comment
		R8 We do not agree that we should provide the assessment to every adjacent PC and TP. We do agree however that if requested by these entities we would provide the assessment. We don't mind sharing information with requestors but would like a longer duration than 30 days due to the fact that we would like to know what type of "reliability need" any entity would have considering that some of the information could be considered CEII. Non disclosure agreements may be needed in order to provide this information.

Response: Effective Date (A5) – The SDT believes the 7 year (84 month) transition to areas where the standard significantly raises planning expectations over the existing standard is more than sufficient for the vast majority of the continent and for most Corrective Action Plans. To the extent additional time is required an entity would need to submit a timely mitigation plan with its Regional Entity organization. No change made.

The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made.

In Requirement R2, Part 2.7, it is stated that a Corrective Action Plan is not required solely for a "single sensitivity study". The standard envisions a portfolio of sensitivity analyses being established for a planning area and the standard does not require Corrective Action Plans for single sensitivity results that may have placed the system in a greater stressed analysis (i.e., heavy system transfers) for its initial (P0) sensitivity model over other models that did not identify performance criteria violations for the same Contingency event studied. No change made.

If a Regional Entity acts as your "Planning Coordinator" then tasks between the Planning Coordinator and Transmission Planner are to be defined as part of Requirement R7. The standard does not prohibit the use of valid studies performed by 3rd parties for a given planning area. No change made.

In regards to Requirement R3, Part 3.4.1, the SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the Planning Assessment. No change made.

Both the registered Transmission Planner and Planning Coordinator have functional entity responsibility for Transmission system planning as defined by NERC's Functional Model. The SDT believes the new TPL-001-2 is appropriately aimed at both throughout the standard. Additionally, Requirement R7 should address the commenter's concern and if greater responsibility can be agreed upon for the Planning Coordinator for a particular area of the continent the standard would not prohibit such a determination. No change made.

The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line

Organization	Yes/ No	Question 3 Comment
to trip. No change made. This standard does not address the studies performed by NERC or its model building practices. The SDT and (based on the recent ballot approval of 74%) the majority of industry support Requirement R8 – no change made.		
MRO's NERC Standards Review Forum		The NSRF recommends that the term, "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems, which is the definition of the NERC Glossary term, "System". These locations are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6
Muscatine Power and Water		MP&W recommends that the term "System" be replaced with "BES" in various places throughout the standard when the reference should not be to the collective generation, transmission, and distribution systems. This is the current definition of the NERC Glossary term "System". The locations where "System" can be found in the Standard are: R2.1.4, R2.1.5, R2.4.3, R2.6.2, R2.7, R2.7.1, R2.7.4, R2.8.1, R2.8.2, R3.5, R4.5, R5, and R6.
Response: Even though the capitalized term "System" includes distribution components, the SDT believes that its usage within this standard is correct because the Reliability Standards apply only to the BES. Therefore, adding additional qualifiers is not needed. No change made.		
BC Hydro		BC Hydro agrees with merging the standards together into one and we feel the new version brings further clarity to the annual planning assessment. BC Hydro would vote Affirmative for bringing clarity, however we do not believe the rewording in Footnote 9 is clear which is why we are voting Negative. Footnote B, as approved by the NERC Board of Trustees on February 17, 2011 was reworded as Foot Note 9 in the proposed TPL 001-2 draft 7 amendment. This rewording still does not clearly define what impact the proposed revision would have on the curtailment of firm transfers in the regional entities.
Response: The equivalent of the revised footnote 'b' as approved by the NERC Board of Trustees on February 17, 2011 is addressed by the combination of two footnotes – footnote 9 and footnote 12 – in the new proposed TPL-001-2 standard. The SDT believes that footnote 9 appropriately allows interruption of Firm Transmission Service as both a corrective action to the initial event studied and as a permissible intermediate "system adjustment" when evaluating a multiple Contingency event such as P3 or P6. The reliance on the interruption of Firm Transmission Service in the Planning Horizon is limited in two ways. First, there must be no planned use of firm Load shedding and second, the planner must be able to demonstrate that the curtailment is supported by a valid re-dispatch of generation that would be "obligated to re-dispatch." Therefore, the planner cannot simply re-dispatch units outside the area of control for the transmission system for which it is reviewing – the re-dispatch must be valid and realistic. No change made.		

Organization	Yes/ No	Question 3 Comment
Entergy Services		Footnote 12 to Table 1 concerning non-consequential load loss should be clarified. The existing language will result in difficulties in proving compliance. Suggested language would be:"Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of a P1 or P2 event and where the location of the planned loss of Demand is limited to those Transmission Facilities made radial.
Response: The SDT in a separate standards development project - Project 2010-11 TPL Table 1 Order – attempted the radial concept described by the commenter in its revision of footnote 'b' as used in the existing set of TPL standards. The proposed "radial" footnote 'b' was presented for industry ballot from 05/17/10 through 05/27/10 and failed at 63.8%. Following an industry technical conference, the SDT continued to work on footnote 'b' and a revised version was approved by the NERC Board of Trustees on February 17, 2011. The combination of footnotes 9 and 12 consistently apply the industry approved revised footnote 'b' in the new standard. No change made.		
Tri-State Generation and Transmission Assn., Inc.		R1.1 to "System models used for Steady State and Stability Analysis shall represent:" Much of what is in R1.1 is unnecessary for Short Circuit studies. In contrast, there are items not mentioned in R1.1 that are necessary for short circuit studies. R2.1.4 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.1.4 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? In R2.3, change the first sentence to read "The short circuit analysis portion of the Planning Assessment shall be conducted annually, using one of the cases described in 2.1.1, addressing the Near-Term Transmission Planning Horizon and can be supported by current or past studies as qualified in Requirement R2, Part 2.6." There appears to be no reason to perform short circuit studies for all three Near-Term Transmission Planning Horizon cases. R2.4.3 requires sensitivity analysis to study "a range of credible conditions that demonstrate a measurable change". How will the required actions in R2.4.3 be documented or measured, and what is accomplished by performing sensitivity analysis in the context of a system performance assessment? R2.7.1 remove the last bullet. We believe these programs are already factored into the load forecast, as they are associated with resource scheduling and planning load serving, and not transmission planning. In particular, DSM measures would fall under R2.4.1, and the term "new technologies, or other initiatives" The language of Requirement 3 unnecessarily repeats the language of R1 and R2. As now written, R3 states "For the steady state portion of the Planning Assessment, each Transmission Planner and Planning

Organization	Yes/ No	Question 3 Comment
		Coordinator shall perform studies for the Near-Term and Long-Term Transmission Planning Horizons in Requirement R2, Parts 2.1, and 2.2. The studies shall be based on computer simulation models using data provided in Requirement R1.” R3 We recommend that the introductory language in Requirement R3 be changed to read “The studies in Requirement R2, Parts 2.1, and 2.2 shall be performed using models as defined in Requirement R1 in accordance with the following criteria.” We believe that Requirements 3.1 and 3.4 should be combined into R3.1, eliminating R3.4. It is redundant to have Requirement 3.1 say “perform R3.4”. We recommend that R3.4 be deleted and that R3.1 be replaced with:R3.1 Planning event studies shall be performed in accordance with “Table 1 - Steady State & Stability Performance Planning Events;” and shall be based on a supportable Contingency list. Comment: The content of 3.4.1 was intentionally omitted as it is redundant with R7. Also, the language “...more severe System impacts...” was intentionally omitted as it could be subject to a wide range of interpretations.Similarly, we recommend that R3.5 be deleted and that R3.2 be replaced with:R3.2 Extreme event studies shall be performed in accordance with “Table 1 - Steady State & Stability Extreme Events;” and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R3.2 language:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the event(s) shall be conducted. Comment: As before, the language “...more severe System impacts...” was intentionally omitted as it could be subject to a wide range of interpretations. We recommend removing the second bullet of R3.3.1, “Tripping of Transmission elements where relay loadability limits are exceeded” for the following reasons:1. There is currently no tool to model relay loadability characteristics in Steady State analysis. 2. Requirement R3.3.1 would require inclusion of relay models in modeling data that are not currently provided. MOD-012 does not require impedance or overcurrent relay models to be submitted.3. In Requirement 3.3.1, the second bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. At best an individual point could be chosen to model relays based on a selected power factor. We recommend changing the opening text of Requirement R.3.3.2 to say “Simulate the expected automatic or manual operation...” Subrequirement R4.1.2 represents a tremendous increase in dynamic modeling complexity. Modeling relay

Organization	Yes/ No	Question 3 Comment
		action during apparent impedance swings would require inclusion of impedance relay models in modeling data that are not required to be submitted in MOD-012. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. We believe that Requirements 4.1 and 4.4 should be combined into R4.1 as shown below and R4.4 should be deleted. It is redundant to have Requirement 4.1 say "perform R4.4." We recommend R4.1 language be revised to read as follows:R4.1 Planning event studies shall be performed in accordance with "Table 1 - Steady State & Stability Performance Planning Events;" and shall be based on a supportable Contingency list.Comment: The content of 4.4.1 should be omitted as it is redundant with R7. Also, the language "...more severe System impacts..." should be omitted as it could be subject to a wide range of interpretations. Similarly, R4.5 should be deleted and R4.2 should be replaced with:R4.2 Extreme event studies shall be performed in accordance with "Table 1 - Steady State & Stability Extreme Events;" and shall be based on a supportable Contingency list. We recommend the following new requirement be inserted after the revised R4.2:Should the extreme event studies identify potential Cascading, an evaluation of possible actions designed to reduce the likelihood or mitigate the consequences and adverse impacts of the even(s) shall be conducted. Comment: As before, the language "...more severe System impacts..." was intentionally omitted as it could be subject to a wide range of interpretations. Clarify the first bullet in Requirement R4, part 4.3.1 by changing it to "High-speed (less than 1 second) reclosing, where the fault has cleared, and high-speed reclosing into the permanent fault , but in each case only if high-speed reclosing is utilized". In Requirement R4, part 4.3.1, third bullet, it is impossible to model complete and accurate relay loadability using present-day steady state simulation tools. Existing applications do have impedance relay models, but these models do not model many relay capabilities- for example, non-circular protection regions and load-encroachment. We recommend removing this bullet. The comment statement we made above referring to R4.1.2 also applies to R4.3.1. MOD-012 does not require reclosing relay model data to be submitted. If such modeling is necessary, then the corresponding data requirements need to be addressed in MOD standards. Furthermore, there is not a standard built-in reclosing relay model in current stability simulation tools. Comments regarding Table 1-We assume the headnote i. to Table 1 - "The response of voltage sensitive Load..." - means that studies must not rely on end-user load tripping to meet the performance requirements defined in TPL-001-2 but that it should be modeled (when known) so that its occurrence would be evident.

Organization	Yes/ No	Question 3 Comment
		We don't see the need to apply Footnote 12 to only certain contingency categories or certain events in categories. Recommend putting the footnote in the column header just as with Footnotes 1, 2, 3, and 4.Recommend changing "utilized" in Measurement M3 to "performed."Recommend changing "utilized" in Measurement M4 to "performed."Modify Measurement M7 to "Each Planning Coordinator shall provide dated documentation on roles and responsibilities of its Transmission Planners, such as..." The deleted phrase, "in conjunction with each of its Transmission Planners," appears to be unnecessary.

Response: Requirement R1, Part 1.1 – The SDT believes that the planners must have the general information in Requirement R1, Part 1.1 in order to conduct the necessary studies for steady state, stability, and short circuit. The requirement states that the planner shall maintain System models, not to have a single model that covers all three categories. The SDT believes that the planner will need the items in Requirement R1, Part 1.1 to develop the smaller set of items that are necessary for their short circuit models. No change made.

Requirement R2, Part 2.1.4 – This item requires the planner to show evidence of one or more sensitivity studies which show appreciable change from the prior projected (P0) system condition (pre-sensitivity adjustment). Measurable changes for the revised P0 system condition could be evidenced by line or transformer flows, voltages, a change in dispatch, load increase, etc., assuming the change places additional stress on a portion of the system being reviewed for the sensitivity studied. The sensitivity analysis is important for the applicable entity to better understand their system's vulnerability to alternate "base (P0)" conditions. The intent is to develop a portfolio of potential credible conditions so that the planner better understands potential vulnerabilities. In the Corrective Action Plans (CAP) area of the standard, Requirement R2, Part 2.7, a CAP may be required if a Planning Event shows performance criteria concerns for one or more sensitivity scenarios. No change made.

Requirement R2, Part 2.3 – The standard states that the planner shall maintain System models, not to have a single model that covers all three categories - for steady state, stability, and short circuit. It is common within many organizations that separate models are maintained for short circuit analysis since they require breaker configuration details not contained within steady-state load flows. Additionally, short circuit models may not have end-use Load represented but rather emphasis is on system topology, impedance, generation dispatch, fault location etc. No change made.

Requirement R2, Part 2.4.3 – same response as Requirement R2, Part 2.1.4 above.

Requirement R2, Part 2.7.1 – The SDT disagrees that the last bulleted item which includes use of a rate application or DSM program would be inclusive to the forecasted Load within the model studied. No change made.

Requirement R3 – The SDT clarifies that Requirement R2 refers to an "annual assessment" which collectively includes current or past studies, Corrective Action Plans, etc. required for steady-state, stability, and short circuit analysis. Requirement R3 deals with a portion of the overall assessment and is focused on the

Organization	Yes/ No	Question 3 Comment
steady-state “study” requirements for the Near-Term and Long-Term Transmission Planning Horizons. No change made. Requirement R3, Part 3.1 – The SDT did not receive any significant industry objection to having Parts 3.1 and 3.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.2 – The SDT did not receive any significant industry objection to having Parts 3.2 and 3.5 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R3, Part 3.4.1 and Requirement R7 are uniquely different and not redundant as suggested by the commenter. No change made. Requirement R3, Part 3.5 (proposed new 3.2 by commenter) – The commenter finds the term “more severe System impacts” too open to interpretation and suggests a focus on Cascading conditions. The SDT believes the requirement is clear as written and that the statement “more severe System impacts” is used to describe the latitude in engineering judgment afforded to the planner in developing its extreme Contingency list. Action is only required on the subset of items that show the potential for Cascading. No change made. Requirement R3, Part 3.3.1, bullet 2 – this does not require an “automatic” modeling feature but rather it could be further subsequent manual analysis performed as needed for a given Planning Event. For example, if a line flow shows >150% loading the planner may need to trip the circuit to see if a stable condition results and what performance criteria issues may be present. To the extent this could be automated through programming the planner may do so at their discretion. No change made. For similar reasons stated in the response to Requirement R3, Part 3.5, the SDT does not find the phrase “more severe System impacts” as vague and open to interpretation. No change made. Requirement R3, Part 3.3.1 - The SDT language does not require comprehensive relaying models. No change made. Requirement R3, Part 3.3.2 - The SDT does not believe the proposed wording changes provide any clarity and finds the item clear as stated. No change made. Requirement R4, Part 4.1.2 – The “apparent impedance swing” is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. With that explanation, the SDT does not believe the modeling requirements are overly complex or difficult to achieve. No change		

Organization	Yes/ No	Question 3 Comment
made. Requirement R4, Parts 4.1 and 4.4 - The SDT did not receive any significant industry objection to having Parts 4.1 and 4.4 separated. The proposed change is based on a formatting and style preference and does not address a reliability gap in the standard. No change made. Requirement R4, Part 4.5 - the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, first bullet – the SDT does not believe the proposed wording changes are warranted and finds the item clear as stated. No change made. Requirement R4, Part 4.3.1, third bullet – The SDT language in Requirement R4, Part 4.3.1 states "The analyses shall include the impact of subsequent" and does not require comprehensive relaying models. However, it does require that the planner take into account the effects of System Protection on System performance. No change made. Table 1 header note "i" – The SDT notes that this item only applies to steady-state load flow analysis and no assumed shedding of non-consequential sensitive Load is permitted for the steady-state analysis unless it is to be intentionally dropped as part of a Corrective Action Plan where warranted. No change made.		
Hydro One Networks Inc.		A. Regarding Requirement 1.1.2, assessment of "known outages... with a duration of at least 6 months", are dealt with in the operational studies rather than planning studies. In addition, any adverse impact that these outages might have, are mitigated by operational decisions rather than "planning" decisions within a 6-month horizon. It is suggested to move this requirement out of TPL standards and instead include it a relevant operational standards. B. The statement in R 2.1.4, "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", leaves room for very different interpretations by PCs and TPs as to the number and type of required sensitivity studies. Are all interpretations, based on the engineering judgment of the PC and TP, acceptable? C. The language of R 2.1.4 and 2.4.3 allowing to perform one or more sensitivities appears to be inconsistent with the language in R 2.7.2 which requires multiple sensitivities to determine if actions to resolve performance deficiencies are necessary. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study?

Organization	Yes/ No	Question 3 Comment
		D. The language of Requirement 2.1.5, "spare strategy", appears to be open-ended regarding the number of permutations to be analyzed. It is suggested to move this requirement out of TPL standard and instead have this issue dealt with in the operational standards. E. In R 2.2, the statement "be supported by the following annual current study, supplemented with qualified past studies" should be replaced with a similar statement in R 2.1 which says: "be supported by current annual studies or qualified past studies". F. In R 4.1.1, "For planning event P1: No generating unit shall pull out of synchronism" is too restrictive. In many cases a P1 event may result in instability of a small nearby generator without a significant impact on the reliability of BES. The same requirement states that "A generator being disconnected from the System ... by a Special Protection System is not considered pulling out of synchronism". If rejection of ANY generator by SPS is acceptable, why should instability of a small generator, resulting in its disconnection by its protection without a severe impact on the system, be unacceptable in all circumstances? If this requirement is unchanged, it dictates the addition of an SPS (Generation Rejection) for any unit that might go unstable without any benefit for the reliability of the BES. G. In Table 1, Event 1 of Category P2 and related Footnote 7 (simulation of LEO condition) are not clear (concern with the use of the word "possibly"). If the intension is to simulate LEO condition of tapped lines, this should be clearly stated in the table (without reference to "Opening of a line section" and use of different language in the footnote).

Response: A: The SDT disagrees with the view that outages of 6-months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

B. The standard does not mandate the number of sensitivity analyses performed nor the number of adjustments made and engineering judgment of the Transmission Planner and Planning Coordinator is acceptable. No change made.

C. Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. The situation described ~~would~~ could be considered multiple sensitivity studies, if the multiple simulations represent more than one of the studies in Requirement R2, Part 2.1.1 and 2.1.2 or Requirement R2, Part 2.4.1 and 2.4.2. No change made.

D. The spare equipment strategy is an important planning aspect to better assist operations. The SDT disagrees that the number of permutations is open-ended. The evaluation is simply a new P0 condition starting with a long lead-time (one year or more) facility removed from service followed by an analysis

Organization	Yes/ No	Question 3 Comment
covering the P0, P1 and P2 studies. No change made. E. The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. F. The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by your Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made. G. Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made.		
Arizona Public Service Company		AZPS would like to reiterate its "Affirmative" voting recommendation with regard to the proposed revisions to the Standard. AZPS erroneously entered a "Negative" Standard vote for one of its voting segments.
Transmission Strategies, LLC		The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace.
Response: Thank you for your support.		
NIPSCO		1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six months. This is a little confusing to me. Does this mean the outage must last at least six months?Or does this mean at least model outages that last six months or more. If it is the latter then, I'm not sure that is stringent enough.There may be known critical outages occurring over peak that do not last 6 months. If non-consequential load loss is not allowed for loss of one element, then what about the next contingency? Couldn't that result in having to interrupt Firm service? Is that okay as a corrective action plan in the outage coordination horizon?Does this apply to both near-term and long-term planning? If so, we probably need to model additional unplanned potential outages on top of n-1 conditions.

Organization	Yes/ No	Question 3 Comment
		Lastly. in section 2.1.4 should there be a category for high/low wind conditions?

Response: Requirement R1, Part 1.1.2 is related to known existing conditions or known future conditions of facilities being removed from service; i.e., a construction project that requires an existing facility to be de-energized for a period of 6-months or more. This requirement should not be confused with hypothetical situations that could result in an extended loss of a facility. Those situations are the intended purpose of a sound spare equipment strategy. The standard only requires analysis of known or planned outages of 6-months or greater to be included within a P0 system condition. The planner could review shorter duration planned outages as part of its sensitivity analysis portfolio. No change made.

The SDT does not believe there is a need to account for a high/low wind condition situation. The intended purpose of this suggested condition within the sensitivity portfolio is not clear. No change made.

Organization	Yes/ No	Question 3 Comment
ReliabilityFirst		1. Requirement 8 and 8.1 uses the language of “Planning Assessment results”. This language is not defined in the section of the standard that defines the terms of use. For consistency “Planning Assessment results” should be replaced with “Planning Assessment”. 2. Requirement 2.1.5 has statements that are ambiguous. What is considered major transmission equipment? What is an entity’s “spare equipment strategy”? The requirement is not clear as to how many power flow models are required (one per piece of “major transmission equipment” without a spare, or one model with every piece of “major transmission equipment” without a spare being out of service)? As written, if an entity has no “spare equipment strategy” they could be exempt from this requirement. 3. We interpret the use of bullet points in Requirement 3.3.1 to mean that either one of the statements can be chosen. This requirement should be written where all the bulleted statements are included in the analyses.

Response:

1. The SDT sees no reliability reason or clarity for the change suggested. No change made.
2. Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity’s system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a “long lead-time” scenario. No change made.

Organization	Yes/ No	Question 3 Comment
3. The bulleted items of Requirement R3, Part 3.3.1 were meant to be inclusive. This means that the use of bullets here was incorrect and the items should be numbered elements. This same change was made to Requirement R4, Part 4.3.1. **3.3.1.1** Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. **3.3.1.2** Tripping of Transmission elements where relay loadability limits are exceeded. **4.3.1.1** Successful high speed (less than one second) reclosing and unsuccessful high speed reclosing into a Fault where high speed reclosing is utilized. **4.3.1.2** Tripping of generators where simulations show generator bus voltages or high side of the GSU voltages are less than known or assumed generator low voltage ride through capability. Include in the assessment any assumptions made. **4.3.1.3** Tripping of Transmission lines and transformers where transient swings cause Protection System operation based on generic or actual relay models.		
ITC		ITC COMMENTS on TPL-001 voteITC will reluctantly vote to approve the draft standard. While we have concerns, we are voting to approve this standard because we believe the positive elements outweigh the portions of the draft standard that we object to. It is important that the improved requirements that effectively “raise the bar” over the existing standard should become effective sooner rather than later. A negative vote, which might cause a further delay in implementation of the standard, would be the least desirable outcome. However, we still believe that the VSL that would find that an entity had committed a “severe” violation for failure to distribute its planning assessment to an adjacent Transmission Planner or Planning Coordinator has the potential to overly punish a simple error in oversight. We would agree that willfully withholding an assessment from a neighbor or a valid requestor justifies a severe violation but an administrative or clerical oversight does not. For example, it might escape our attention that an entity, particularly a smaller one, registers as a TP or TP. As far as we know, there is no requirement that a registrant, or even one who de-registers, must notify an “adjacent” TP or PC of their change in status. As written, the standard requires you be found in “severe” violation, even if that new entity fails to notify you of their change in status. You would still be in severe violation even if they later ask for your planning assessment. Even if the standard passes, we request that this VSL be fixed to make the distinction between an administrative error and willful neglect. Our response to question 2 offers a suggested method to do this.
Response: Requirement R8 is an important aspect of the new TPL-001-2 standard to communicate results with neighboring systems and those demonstrating a reliability need. The SDT notes that the VSL Guidelines require a Severe VSL for each and every requirement but encourages graded (multiple level) VSLs where		

Organization	Yes/ No	Question 3 Comment
possible. In regard to Requirement R8, the SDT has established four VSLs. It is noted that an entity can be up to 120 days (~ 4 months) late in its delivery of the information and remain in the Lower VSL category before being exposed to the Severe VSL category. The 10 day increment in the other VSL categories, above the 120 day Lower VSL, conforms to NERC's VSL Guidelines. See the response to your suggested VSL changes in Question 2, however, it is noted that no changes were made to the Requirement R8 VSLs. No change made.		
South Carolina Electric and Gas		R1 does not seem to address errors in data that have been introduced in the latest model data. In addition, R1 and its VSL may be interpreted to exclude the use of past studies. The Implementation Plan should include a five year delay in the effective date for short circuit studies for parts 2.3 and 2.8 of R2 because these studies are not required in the current Version 0 standards.
Response: Requirement R1 of the new TPL-001-2 standard requires the Transmission Planner and Planning Coordinator to maintain System models within its respective area of responsibility. The requirement indicates that information received via MOD-010 and MOD-012 shall be "supplemented by other sources as needed" and to the extent errors and omissions were to be discovered by, or brought to the attention of, the Transmission Planner or Planning Coordinator Requirement R1 establishes an expectation that these "other sources" would be utilized to accurately "represent the project System conditions" being studied. No change made. Requirement R1 is applicable to models used for both current and past studies. No change made. Implementation Plan, Short Circuit Studies – While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant "raising of the bar" for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Manitoba Hydro		-Why was the Near Team Transmission Planning Horizon definition moved to the Glossary prior to TPL-001-2 approval?- The definition of Non-Consequential Load Loss should not contain '(2) the response of voltage sensitive Load' because voltage sensitive
Response: Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled "FAC Order 729". The two definitions, "Near-term Transmission Planning Horizon" and "Year One" were approved by the Board of Trustees on January 24, 2011. The statement related to the "Non-Consequential Load Loss" definition is incomplete. No change made.		

Organization	Yes/ No	Question 3 Comment
National Grid		R 1.1.2 We recommend the known facility outage duration be defined as facility outage durations lasting at least twelve months. R 1.1. (page 4) System models shall represent: 1.1.1. Existing Facilities 1.1.2. Known outage(s) of generation or Transmission Facility(ies) with a duration of at least six twelve months. 1.1.3 ...... R 2.1.4 We recommend that this requirement be eliminated. We do not see the value of this additional analysis when the number, type and severity of the sensitivity tests are not well defined. These tests are then used to define Corrective Action Plans in cases only where multiple tests show performance deficiencies. R 2.1.5 Spare equipment strategies are typically designed to prevent long outages (possibility a year or more) of equipment with very long lead times. Any such strategy "could" result in these long outages depending upon the number of failures that may be postulated.This requirement is misleading and we thus recommend it be eliminated. R 2.2 We recommend the language for R 2.2 should be consistent with 2.1 for example - use "current or qualified past studies" instead of "the following annual current study." R 2.6.2 We recommend that the wording of this requirement remain unchanged. R 2.7.1 This portion of the requirement provides a list of "acceptable" Corrective Action Plans. It provides equal weight to infrastructure reinforcements and Special Protection Systems as means to mitigate violations resulting form single or multiple contingencies at both the EHV and HV levels.National Grid's position is that a national standard should not endorse the use of Special Protection Systems as corrective actions to mitigate single contingency violations.Local Northeast Planning Criteria indicates that special protection systems (SPS) shall be used judiciously and may be used to provide protection for infrequent contingencies, or for temporary conditions that may exist such as project delays, unusual combinations of system demand and equipment outages or availability, or specific equipment maintenance outages. A SPS may also be applied to preserve system integrity in the event of severe facility outages and extreme contingencies. The decision to employ a SPS shall take into account the complexity of the scheme and the consequences of correct or incorrect operation as well as its benefits. We are further of the opinion that specific methods of correcting system performance deficiencies should not be specified in a National Standard. We thus recommend that the Corrective Action List be eliminated from this requirement as illustrated below. 2.7.1. List System deficiencies and the associated actions needed to achieve required System performance. R 2.7.2 We feel that this requirement and requirement R 2.1.4 adds ambiguity to the process as we have

Organization	Yes/ No	Question 3 Comment
		indicated above. We thus recommend that this requirement be eliminated. R 3.3.1 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" Contingency analyses for Requirement R3, Parts 3.1 & 3.2 shall: 3.3.1. Simulate the removal of all elements that the Protection System and other automatic controls are expected to disconnect for each Contingency without operator intervention. The analyses shall include the impact of subsequent: o Tripping of generators where simulations show generator bus voltages or high side of the generation step up (GSU) voltages are less than known or assumed minimum generator steady state or ride through voltage limitations. Include in the assessment any assumptions made. R 3.4.1 We would recommend the following addition as a clarification to the required information exchange: 3.4. Those planning events in Table 1, that are expected to produce more severe System impacts on its portion of the BES, shall be identified and a list of those Contingencies to be evaluated for System performance in Requirement R3, Part 3.1 created. The rationale for those Contingencies selected for evaluation shall be available as supporting information. 3.4.1. The Planning Coordinator and Transmission Planner shall coordinate with adjacent Planning Coordinators and Transmission Planners to ensure that Contingencies on adjacent Systems which may impact their respective Systems are included in the Contingency list. R 8.1 National Grid's concern regarding this requirement stems from the apparent open ended time frame afforded report recipients in their review of the Planning Assessment. This has the potential to stall the review process. National Grid thus recommends that any recipient of the Planning Assessments be given a specific time period for their response as indicated in R 8.1 below. R8. Each Planning Coordinator and Transmission Planner shall distribute its Planning Assessment results to adjacent Planning Coordinators, and adjacent Transmission Planners, within 90 calendar days of completing its Planning Assessment, and to any functional entity that has a reliability related need and submits a written request for the information within 30 days of sucha request. [Violation Risk Factor: LowMedium] [Time Horizon: Long-term Planning] 8.1. The recipient of the Planning Assessment results shall provides documented final comments on the results within 90 calendar days of receipt of the Planning Assessment. The respective Planning Coordinator or Transmission Planner shall provide a documented response to that recipient within 90 calendar days of receipt of those comments. Table 1 Steady State & Stability Performance Planning Events (Page10). The event description for

Organization	Yes/ No	Question 3 Comment
		Category P2 Event 1. along with the accompanying footnote 7 (Page 14) creates some confusion for multi-terminal lines. We recommend that Footnote 7 be eliminated and the event description be changed as follows: Category Initial Conditions Event P2 Normal System 1. Opening of a single load interrupting device at one terminal of a line without a fault. Table 1 (Planning Events and Extreme Events) Footnote 12 (Page 14).We are concerned that additional stakeholder process indicated in Footnote 12 has the potential to stall the Planning Assessment review process. We recommend that reference to this new process be eliminated from the Footnote.Our additional, concerns with Footnote 12 are addressed in comments originally provided by ISO-NE. We agree with their following comments : The following language for Footnote 12 is proposed:"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."If Footnote 12 in Table 1 must be retained, the following language is proposed: "An objective of the planning process shall be to minimize the likelihood and magnitude of interruption of Demand, (excluding Interruptible Demand or Demand-Side Management), following Contingency events. However, it is recognized that Demand will be interrupted if it is directly served by the Elements removed from service as a result of the Contingency. Furthermore, in limited circumstances Demand may need to be interrupted to address BES performance requirements. When interruption of Demand is utilized within the planning process to address BES performance requirements, such interruption is limited to: a. Interruptible Demand or Demand-Side Managementb. Circumstances where the uses of Demand interruption not directly interrupted by the contingency are documentedc. Curtailment of firm transfers is allowed to meet BES performance requirements and meet applicable Facility Ratings, where it can be demonstrated it does not result in the interruption of any Demand (other than Interruptible Demand or Demand Side Management)"

Response: Requirement R1, Part 1.1.2 – The SDT and a majority of industry stakeholder support the 6-month period stated in the requirement. No change made.

Requirement R1, Part 1.1 – Same comment as above. No change made.

Requirement R2, Part 2.1.4 – Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made.

Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing

Organization	Yes/ No	Question 3 Comment
spare equipment strategy to provide a means of returning to service (in less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity's system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a "long lead-time" scenario. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans. The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Part 2.6 – The changes made to this requirement in the last draft were essentially style changes and the most substantive change is the introduction of documentation required to support the technical rationale for determining whether or not material changes have occurred. This was a recommendation made by the Quality Review process and agreed to by the SDT. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that actions that could be part of a Corrective Action Plan (CAP) should be eliminated. In regard to the concern of allowing SPS within the CAP, this view is not shared across the continent-wide footprint and National Grid and its Regional Entity always have the ability to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R2, Part 2.7.2 - Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a Corrective Action Plan that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Requirement R3, Part 3.4.1 – The additional information suggested was not implemented as it did not add to reliability or clarify the issue beyond the present wording. No change made. Requirement R8, Part 8.1 – The SDT does not see a reliability related need for the suggestion and believes a response regarding a Planning Assessment is warranted no matter when raised by the reviewing party. No change made.		

Organization	Yes/ No	Question 3 Comment
Table 1, footnote 7 – The SDT added the footnote to further explain its intent for P2-1 and to ensure that the planner assess the voltage of a load bus that was on a radial line. The word "possibly" was used since having load on a radial is not always the outcome of opening one end of a line section. No change made. Table 1, Footnote 12 – The SDT believes the stakeholder process provides a level of transparency needed when an entity intends to utilize provisions offered by footnote 12 (and footnote 9). No change made.		
TVA TP&C		TVA - has following comments: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 BES reliability is not impacted. Otherwise significant capital improvements will be required that will have no overall reliability gain for the Bulk Electric System. In R4.1.1, TVA is concerned that no generating unit (including distributed generation) 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. Table 1 contains both planning events and extreme events. Suggest labeling the planning events as Table 1 and the extreme events as Table 2 to help reduce confusion. VSL for R1 does not seem to address issues where data errors have been introduced into the latest model data. Also, R1 and its VSL may be interpreted to exclude the use of past models. The Implementation Plan should include a five-year delay in the effective date for short circuit studies (R2 parts 2.3 and 2.8) since these studies are a new TPL requirement and are not required in the current version 0 standards.
Response: The SDT has taken care to ensure consistency in footnote 12 (and footnote 9) with the prior footnote 'b' revision supported by industry, approved by the NERC Board of Trustees, and submitted for regulatory approval. No change made. Requirement R4, Part 4.1.1 - The SDT respectfully disagrees with the commenter. For a P1 single Contingency event, the SDT believes, and a majority of industry stakeholders find it reasonable, that no Bulk Electric System (BES) generation unit be pulled out of synchronism due to the P1 event studied. If the "small" nearby unit is served below threshold kV and MW size limitations set by the Regional Entity to qualify as a BES unit, the unit would not be within scope of the standard. No change made.		

Organization	Yes/ No	Question 3 Comment
Desire for Two Tables – This has been vetted within industry in prior comment/ballot periods. The majority of stakeholders support the current format. No change made. Requirement R1 VSL – The requirement indicates that supplied data may have to be supplemented as appropriate. The SDT believes that this covers correcting any data errors. The SDT sees no reason why the current language invalidates the use of past models as long as they meet the requirements. No change made. While short circuit study requirements may be new in the realm of mandatory enforceable standards, the SDT does not believe that they present a significant “raising of the bar” for industry. The SDT believes that prudent short circuit practices are effectively in place today to ensure safe operation of the equipment. Therefore, no extension in the Implementation Plan was made in regard to short circuit studies.		
Independent Electricity System Operator		See our response to Q1.
Response: See response to Q1.		
NBSO		Items that, if not addressed, will likely cause a negative vote from NBSO: NBSO believes that R1.1.2 is more appropriately addressed in the operational timeframe. Perhaps more appropriate alternatives could include:-only considering planned outages with durations of one year or more (in-line with typical planning timeframes), or -requiring that facilities with planned outages lasting over the complete duration of time period being studied be modeled out of service. R2.1.5 may significantly increase the demands of the planning assessments with little gain in reliability. Depending on interpretation, R2.1.5 could exponentially increase the work load of the annual planning assessment. NBSO interprets the intent of R2.1.5 to require that entities have, review and evaluate their spare equipment strategies. Perhaps the assessment of a spare equipment strategy would be more appropriately addressed in a separate standard. Further, categories P0, P1 and P2 do not reference footnote 9 in the Initial Condition column. NBSO is unclear if the last sentence of R2.1.5 allows for the curtailment of firm transmission service under the N-1 conditions before the application of category P0, P1 and P2 events. This last sentence states:”...with the conditions that the System is expected to experience during the possible unavailability of the long lead time equipment.” Table 1, note b should be modified to allow for the loss of Firm Transmission Service. This addresses cases where Firm Transmission Service is lost in direct consequence to the event (e.g. loss of one DC pole, an

Organization	Yes/ No	Question 3 Comment
		interface comprised of a single line, a bus fault that clears multiple lines in an interface, etc...) Individual items that, if not addressed, may not cause NBSO to vote Negative, but in combination may result in a negative vote:The definitions of “near-term transmission planning horizon” and “year one” have been removed from the standard, yet they are still used in draft 7. Further, the definition of these terms is being filed as part of another project. NBSO is concerned with endorsing a standard based on terms whose definitions may change independently of this project. For R7, NBSO is concerned that one entity may be found noncompliant should another entity fail to meet their agreed upon responsibilities. For example, a PC may be relying on the results from a TP’s studies to complete its own planning assessment, but the TP did not meet their responsibilities. In this case, the PC should not be found non-compliant for an incomplete planning assessment due to the failure of the TP to meet their responsibilities.Contingencies on back to back HVDC facilities are not addressed in the standard.

Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. No change made.

Requirement R2, Part 2.1.5 is intended to analyze the removal of a single piece of long lead time equipment (one year or more) to the extent there is no existing spare equipment strategy to provide a means of returning to service (in a less than one year) a comparable replacement. If this condition exists, then the facility (single element) in question must be removed in the model to establish a new P0 system condition and studies must then be run for P0, P1, and P2 for the new system scenario. The spare equipment strategy must be reviewed for the entity’s system exposure to catastrophic failures resulting in the long lead-time facility outages, however, only one facility must be removed at a time if the condition exists for multiple facilities. A Transmission Planner may have no spare equipment strategy if they are able to demonstrate they are not responsible for any facilities which they believe could place them in a “long lead-time” scenario. No change made.

Requirement R2, Part 2.1.5 & Footnote 9 – Footnote 9 is not applicable to the Initial Condition (Pre-contingency) of P0, P1, and P2 even with a long lead-time device out of service. No change made.

Table 1, footnote ‘b’ - The SDT believes the concern should be addressed by footnote 4, Conditional Firm Transmission Service. No change made.

Removal of Definitions - Two previously proposed definitions that were part of this project were moved to another standard development project – Project 2010-10 titled “FAC Order 729”. The two definitions, “Near-Term Transmission Planning Horizon” and “Year One” were approved by the Board of Trustees on January 24, 2011.

Requirement R7 – The SDT disagrees, having documented clear lines of responsibility should protect against the concern raised. No change made.

Organization	Yes/ No	Question 3 Comment
Back to Back HVDC – The contingent loss of back to back HVDC facilities is included as a transformer. Footnote 5 states, in part, that "Requirements which are applicable to transformers also apply to variable frequency transformers and phase shifting transformers. Therefore, the SDT has not explicitly included back-to-back HVDC as a separate Contingency. No change made.		
Xcel Energy		Effective Date: The effective date section seems to imply that Non-Consequential Load Loss will not be permitted after the 84 month implementation period. We do not believe that was the drafting team's intent and request that it be modified. Footnote # 12 in Table 1, in particular, seems to support our assumption that the team did not intend to disallow it. For reference, the footnote states:"12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to address BES performance requirements. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss is documented, including alternatives evaluated; and where the utilization of Non-Consequential Load Loss is subject to review in an open and transparent stakeholder process that includes addressing stakeholder comments." However, if it was the drafting team's intent to not allow Non-consequential Load Loss after the 84 month implementation period, we disagree and ask the team to reconsider. Particularly for rural areas, in some cases, this will be the only action possible. R2.1.4: a) We would like to see clarification on the term "sensitivity analysis". Is this in reference to seasonal models and differences in fuel availability? We would like more detail on how this is to be done so that it won't be left up to interpretation. b) We would like the drafting team to consider stratification of the tasks needed to perform a Planning Assessment. In our opinion, having both the TP and PC do exactly the same study produces tremendous and unnecessary duplication. Without stratification, the TPL-001 standard will continue to perpetuate the same paradigm used in the existing TPL-001 through TPL-004 standards. The NERC Functional Model makes a clear distinction between PC and TP functions/responsibilities. It is not clear why that distinction is not leveraged in the new TPL-001 standard. This will be particularly troublesome in areas where an ISO or RTO is the Planning Coordinator. In order for the RTO/ISO, as the PC, to be able to do their Planning Assessment, the Transmission Planners would have to provide a lot of detailed input data. So, in effect, both the PC and TP would be performing their assessment from the same data. It would make more sense if the RTO (as the PC) performed the required studies on the 500-345 kV network and the TP performed the required studies on everything below 230 KV.

Organization	Yes/ No	Question 3 Comment
		We also recommend the allowance for utilization of a regional assessment, instead of performing your own, due to individual entity resource constraints. R2.4.1: We would like to see better clarity on what an Aggregate system load model is and how granular it should be. If the intent is for the model to contain a very detailed representation of the load system, then it may take a longer time to implement. R3.4.1: a) This type of coordination could be difficult due to other adjacent entities on different schedules and some may not have the amount of detail to incorporate into another's processes. We know this is generally covered in coordination of real time operations and wonder if it is appropriate to require this type of coordination in the long term process. Is there already an operational standard that covers this? Would it be better to address this in the operational standards? We would like the roles of the coordinators vs. the planners to be clarified in order to ensure that no work is being duplicated. b) PC's between regions, such as RTOs, are already coordinating for long term studies. In these cases, we feel the PC should alone be responsible for the requirements, rather than also the TPs. c) Can we get a clear definition of what apparent impedance swings means? We interpret it as rotor angle stability. R4.3.1: We would like to see that the detailed data is incorporated back into the NERC modeling processes and create a more detailed model with better accuracy. R8: We do not agree with the requirement to provide the assessment to every adjacent PC and TP because we fail to see the reliability benefit in doing so. However, we do agree that the PC and TP should be required to provide the assessment to any of these entities, if requested. Additionally, for entities that make such requests, we would like to have 90 days instead of 30 to respond. In many cases a non-disclosure agreement will have to be executed due to CEII classification of some information, and this can take several months.

Response: Effective Date - The SDT believes the Effective Date section is sufficiently clear. The use of Non-Consequential Load Loss while discouraged by the standard is permitted when justified and presented in a transparent manner to other stakeholders (footnote 12). No change made.

Sensitivity Analysis – This analysis should be viewed as a modified study of the Peak or off-peak studies required in Requirement R2, Parts 2.1.1 and 2.1.2. The SDT believes the examples provided in the bulleted list of Requirement R2, Part 2.1.4 are sufficiently clear as examples of what could be modified to create the sensitivity model. No change made.

Organization	Yes/ No	Question 3 Comment
Delineation of tasks between Transmission Planner and Planning Coordinator – The issue raised is addressed by Requirement R7. No change made. Regional Assessments – The standard does not prohibit the use of valid studies performed by 3rd parties for use in the assessment results. No change made. Requirement R2, Part 2.4.1 - The "aggregate" dynamic Load model may include high-level assumptions on Load profiles for industrial, commercial, and residential Loads that are applied generically across the planning area study based on the planner's engineering judgment and system knowledge. The model is not required to be "bus" specific. No change made. Requirement R3, Part 3.4.1 - The SDT envisions that knowledge of the applicable Contingencies on neighboring systems would develop over time and be discovered with the results being distributed in Requirement R8. The SDT believes that this is an important improvement to the planning timeframe analysis and that system information learned in the operations environment should most certainly be considered to the extent it improves the robustness of the planning assessment. No change made. Planning Coordinator responsibility – NERC's Functional Model clearly places Transmission planning responsibility both on the Transmission Planner and Planning Coordinator. Requirement R7 should help alleviate any overlap concerns in responsibility. No change made. Apparent Impedance Swings - The "apparent impedance swing" is the trajectory of changes in the apparent impedance seen by a distance relay for various system and Fault conditions. In the case contemplated in Requirement R4, Part 4.1.2, it is the trajectory seen by the distance relay for the initial Fault and the subsequent generator(s) pulling out of synchronism. If that trajectory were to come within the tripping characteristic of the relay for a sufficient length of time, the relay would cause its associated line to trip. No change made. NERC Modeling Process – The standard does not govern NERC actions as they are not a registered entity. To the extent NERC pulls information from a model building process such as MMWG (ERAG) then the models used by NERC will likely contain the information desired. No change made. Requirement R8 – The SDT and a majority of industry support Requirement R8. No change made.		
ISO New England Inc.		We feel previous comments have largely been ignored by the Standards Drafting Team leading to a lack of support for the standard. Overall the standard should be more precise in its language. The following comments are provided for serious consideration with respect to revisions:Comments: From Section A.3 - the introduction please strike the word "probable" as shown below Purpose: Establish Transmission system planning performance requirements within the planning horizon to develop a Bulk Electric System (BES) that will operate reliably over a broad spectrum of System conditions and following a wide range of probable Contingencies This is deterministic contingency testing and this word introduces probability into the standard where it does not belong. For 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

Organization	Yes/ No	Question 3 Comment
		considered (e.g. P0, P1, & P2)). Regional allowances for load shedding under this condition should be acceptable. Duration of known outages should be increased from six months to one year. For R1.1 Part 1.1.6 Delete "required for Load". Resources may also be used for export to other areas, not just internal load. REMOVE INTERCHANGE from 1.1.5 - Definition of Interchange - The inclusion of Interchange requires designing for non-Firm service.In the NERC Glossary of Terms Used the term Interchange is defined as "Energy transfers that cross Balancing Authority boundaries." It is meant to refer to energy transaction 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 are deemed highly interruptible and 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 under TPL-001. 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 or 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 condition 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 or revised as follows: 2.7.2. Corrective Action Plans are not required for performance deficiencies identified in a sensitivity analysis. We 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." For 2.7.1 - We don't believe this list provides value nor should it be included in the standard. Section 3.3 - We feel that the last sentence of 3.3.1 should be removed. This is handled by PRC-023. Line

Organization	Yes/ No	Question 3 Comment
		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.” In Table 1 - The fault descriptions must be clear. They must use “3-phase”, “single-phase-to ground”, or “2-phases-to ground” in the descriptions of a fault rather than SLG (a line is not a phase in electrical terms--single line to ground is not precise enough). In Table 1 - Where two elements are affected by a fault it must be clear whether the requirement is for a single-phase-to ground fault, or a 2-phase-to ground fault. They are different faults that will have different dynamic responses. For Table 1- add a footnote for the term generator to address the treatment of Combined Cycle Generators - “In addition to evaluating the loss of a single generator, the loss of all interrelated generators shall also be considered as a single contingency.” Operating experience has shown that trips of the entire CC facility often occur even on facilities that claim the combined cycle generators are independent. Where a category involves an initial condition representing the loss of a facility followed by an event represeting the loss of a facility such as P3, the standard must be clear as to the amount of time assumed between faults. An assumption may be 30 minutes, but the standard must not leave this unsaid. This clarity must be provided in the Table 1 Notes.In addition, the standard must be clear on the allowable re-adjustments between contingencies such as P3, or better, must be clearly limit the permissible re-adjustments. For example, it is not realistic to assume an unlimited amount of re-dispatch between faults-e.g. the allowable re-adjustment should be limited to actions that can be effectively implemented in less than 30 minutes, such as a, b, c, d, ..., and the amount of generation re-dispatch must not exceed the amount of future planned contingency reserve, or similar language. This clarity must be derivable from the Table 1 Notes.

Response: A.3 Purpose Statement – While admittedly “probable” is somewhat in the eye of the beholder the intent is that Bulk Electric System (BES) should operate reliably for the more “probable” or “credible” Contingencies, i.e., Planning Events (Table 1), and that the BES reliability performance expectation is lower for the less “probable” extreme events. The SDT does not see this statement as defining the standard as probabilistic Contingency planning and agrees that the standard is deterministic planning. No change made.

Requirement R2, Part 1.1.2 – The SDT disagrees that the duration of known outages should be increased from 6 months to one year. The intent is to ensure review of an upcoming construction project requiring certain facilities to be removed from service for long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans (CAP) as required. The SDT believes it is

Organization	Yes/ No	Question 3 Comment
appropriate to study all planning events for the projected system and not limit it to just P0, P1. or P2. Load shedding could be part of a "temporary" CAP when justified by the use of footnote 12. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the Load. The term Load does not depict whether it is located internal or external to the Transmission system footprint. No change made. Requirement R1, Part 1.1.5 – Both firm and non-firm transfers of power should be modeled to the extent they are "known commitments" in the Planning Horizon. The short duration transactions described would likely not be known and therefore should not be included in a planning model. No change made. Requirement R2, Part 2.1.4 – the commenter has missed the key phrase "… by a sufficient amount to stress the System …". So, by definition of the requirement the sensitivity analysis is not intended to lower the overall stress of the system being analyzed. Additionally, Requirement R2, Parts 2.1.4 and 2.4.3 are not inconsistent with Requirement R2, Part 2.7.2. With the various requirements, the planners are required to conduct multiple sensitivities. Therefore, Requirement R2, Part 2.7.2 could be used when the results of these multiple sensitivities identify common concerns. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-Term Transmission Planning Horizon is intentional to drive earlier identification of potential transmission performance limitations and earlier development of Corrective Action Plans (CAPs). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, R2.7.1 – The SDT respectfully disagrees that example actions that could be part of a Corrective Action Plan (CAP) should be eliminated. If an entity takes issue with the use of one of the stated items as part of a CAP, they are always free to go above and beyond the requirements of a NERC standard if they believe such action is warranted. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made. Fault Types – Only single line to ground (SLG) and three-phase (3PH) fault types are covered by the standard. See Table 1, footnote 2 for further information on fault types and standard expectations. No change made. Combined Cycle Plants – If the planner believes it is appropriate to model the tripping of the combined cycle generation as a set then they should do so. Recall, in planning assessments, you are analyzing Contingency events based on electrical Faults and the SDT reminds the commenter that adherence to introductory Table 1 note "c" is required. Additionally, to the extent the combined cycle units deliver their power via a common GSU transformer the loss of the GSU should also address the concern. No change made. System Adjustments – The timing between events which are not common mode events (P3, P6) is not defined by the standard. Engineering judgment should		

Organization	Yes/ No	Question 3 Comment
prevail and if the planner believes a susceptibility to an N-2 event of quick duration places their system at risk then the use of automatic controls should be considered. The only qualifier on System adjustments is that Facility Ratings must be adhered to during the adjustment. So, if you are adhering to a 30-minute Emergency Rating, but are exceeding a 24-hour Emergency Rating then the adjustment must be completed within the time limitation of the rating. No change made.		
Northeast Utilities		The following previous comments that were filed by NU were not addressed by the SDT in the current draft. For NU to support the standard these comments should be addressed or reasons should be provided why they have not been addressed. Repeated below are NU's comments that were filed for the previous draft. Requirement R1, Part 1.1.2 NU requests that the six month duration stated by Requirement R1, Part 1.1.2 should be modified to one year duration to eliminate outages that occur within the "operational planning timeframe". Requirement R1, Part 1.1.6The phrase "required for Load" should be deleted as this confuses the issue.Requirement R2, Part 2.2The language of Requirement R2 Part 2.2 seems to suggest that current annual studies are always required for the long-term steady state assessment. 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. Requirement R2, Parts 2.1.4 & 2.4.31) 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. 2) Requirement R2, Part 2.1.4 and Part 2.4.3 should clarify what is meant by multiple sensitivity studies and one sensitivity study. Will varying only one measurable quantity several times in multiple simulations constitute multiple sensitivity studies or one sensitivity study? Requirement R3, Part 3.3.1NU feels that the last sentence of Requirement R3, 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."
Response: Requirement R1, Part 1.1.2 - The SDT disagrees with the view that outages of 6 months or more should only be reviewed in the operations timeframe. Such an outage could be for an upcoming construction project requiring certain Facilities to be removed from service for a long durations of time and those situations should be evaluated with sufficient lead time to determine any vulnerabilities and development of sufficient Corrective Action Plans as required. The		

Organization	Yes/ No	Question 3 Comment
review of known and planned construction items should not be delayed until the operations timeframe. No change made. Requirement R1, Part 1.1.6 - The SDT does not believe the phrase "required for Load" is confusing. Without the statement, in theory, one could have a model with lots of supply resources but none which are dispatched to serve the load. No change made. Requirement R2, Part 2.2 - The requirement for an annual current steady-state study in the Long-term Transmission Planning Horizon is intentional to drive earlier identification of potential Transmission performance limitations and earlier development of Corrective Action Plans (CAP). The study results can be used as qualified studies as they advance to later years, including moving to the Near-Term Transmission Planning Horizon. No change made. Requirement R2, Parts 2.1.4 & 2.4.3 – The "base case" assumption is described in Requirement R1 by the fact that the P0 model "shall represent the projected System conditions" for the study period. That essentially establishes the "base case" condition. The sensitivity analysis in Requirement R2, Part 2.1.4 is intended to address some potential "what if" conditions that the planner should consider as an alternate base P0 condition. The SDT believes Requirement R2, Part 2.1.4 provides sufficient detail and clarity of the intended purpose of a sensitivity study and defers to engineering judgment in how the alternate base (sensitivity) model is established. Varying one variable multiple times would cover multiple sensitivities. For example, one may vary the Load modeled. If the base condition is a 50/50 forecast model, one sensitivity may be an 80/20 forecast, while yet another is a 90/10 forecast model. No change made. Requirement R3, Part 3.3.1 – The SDT appreciates the concern raised; however, it believes the subsequent tripping of "Transmission elements where relay loadability limits are exceeded" is warranted. The TPL studies may earlier identify and flag relay setting concerns based on required Long-Term Transmission Planning Horizon studies. Within the TPL standard, such a concern would have a CAP that would address the issue which would also meet the expectations of PRC-023. The SDT sees this as a defense in depth approach. No change made.		
MISO		Overall, we remain concerned that the revisions to the TPL standard are not on balance an improvement to the original. The document is not well organized topically, making it more difficult to navigate and understand. If the primary improvements sought in requirements for reliability planning were to increase system performance levels (no loss of firm demand) for certain multiple contingency events, and to ensure more stressed system sensitivities are analyzed, this can be accomplished in a much simpler revision. We do not believe that this standard as written improves the clarity of what is required, and therefore provides an opportunity for greater disputes between compliance monitors and applicable entities, and this is not a positive outcome. We also believe that the standard is too prescriptive as to what critical system conditions must be modeled, as these conditions vary considerably from system to system and within large systems. Table 1-Steady State and Stability Performance Planning Events, Category P5, now includes "non-redundant" relay in the Event column. What is meant by non-redundant relay? It is unclear if the SDT's intent is to provide distinction between a back-up relay and a redundant relay. We recommend that the SDT provide a definition for the term "non-redundant".

Organization	Yes/ No	Question 3 Comment
Consumers Energy	Ballot Comment	We agree with comments submitted by MISO
Response: The SDT and others in industry hold a different opinion in regards to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believe is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states "The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace". No change made. Redundant Relay – Redundant means duplicate capability resulting in the same outcome. The redundant relay is not the same as a back-up relaying capability which may result in more Facilities being removed for failure of the primary/redundant relay to operate as designed. The SDT believes this concept is widely understood by most in industry and does not see the need for a NERC Glossary Definition. No change made.		
New York Independent System Operator		Requirement R2.4.1The NYISO, along with many other systems, has not determined a need to model dynamic loads, and therefore has not benchmarked any such models. The NYISO recommends that prior to the implementation of this requirement a modeling standard should exist that is specific to dynamic loads, including as assessment for the need for dynamic load models.
Response: Requirement 2, Part 2.4.1 – One focus of the dynamic Load model requirement in Requirement R2, Part 2.4.1 is "considering the behavior of induction motor load". The areas of concern for induction motor load are the Peak load periods since Fault Induced Delayed Voltage Recovery (FIDVR) is primarily a concern at a high load levels with a high penetration of induction motor loads. The SDT has spelled out this requirement in the Peak Load studies but did not include the explicit requirement, with focus on induction motor load, for the other load periods. Even though the standard doesn't have the explicit requirement for other load levels, Requirement R1 includes the statement "shall represent projected System conditions", so the planner cannot ignore the dynamic behavior of the load for those other load periods. No change made.		
Ameren		With respect to Requirement R8, will posting the assessment to a secure web site meet the intent of the requirement? What are the Planning Assessment results identified in R8, and how are they different from the Planning Assessment? It appears that the language for R8 is inconsistent with the VSL for R8. The revised language for the VSL for R8 has removed the word "results". For Measurements M3 and M4, there is still some question as to what is to be provided as sufficient evidence of a study. It is not clear whether the study results would be sufficient, or whether the entire powerflow,

Organization	Yes/ No	Question 3 Comment
		stability, or short circuit effort needs to be documented in a formal study report. For example, it is not clear whether contingency lists used in performing the study work would need to be retained as part of the documentation. The items listed as 4.1.1 through 4.1.3 are not requirements but are performance criteria and should be included in the Table 1 only, consistent with the other performance criteria. Overall, we believe that this standard does not improve the clarity of what is required, and would give additional occasions for disputes between compliance monitors and various registered entities. The standard as written is too prescriptive with regard to critical system conditions which are to be modeled. Such conditions would vary considerably for different systems across the continent.

Response: Requirement R8 – Posting results to a secure website with adequate communication that the results are available for review would suffice for Requirement R8. The “Planning Assessment” and “Planning Assessment results” are one and the same. No change made.

Measures M3 and M4 – The evidence could be a combination of summary documented results, the power flow case itself, the Contingency lists, output files showing evidence of the Contingency analysis being performed, etc. No change made.

The SDT believes the items in Requirement R4, Parts 4.1.1 through 4.1.3 are properly located. The standard is the sum of the parts – requirements and the Table and the location of the highlighted items is not critical to the desired outcome. No change made.

Clarity of the standard - The SDT and others in industry hold a different opinion in regard to the standard. The SDT refers you to the comments provided by Transmission Strategies, LLC which well articulates what it believes is the opinion of many in industry evidenced by the 74% approval during the last ballot. Transmission Strategies, LLC states “The SDT, Observers, and the Industry as a whole have put a tremendous amount of thought and work into the development of this latest draft. While nobody should claim that this latest version is perfect, it is far clearer, more in tune with current industry needs, and much improved compared to the existing approved Standards that it will replace”. No change made.