NERC

NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on TPL Table 1 Order (footnote 'b') — Project 20010-11

The TPL Table 1 Order Drafting Team thanks all commenters who submitted comments on the revised footnote. These standards were posted for a 30-day informal public comment period from September 8, 2010 through October 8, 2010. The stakeholders were asked to provide feedback on the standards through a special Electronic Comment Form. There were 42 sets of comments, including comments from more than 96 different people from approximately 75 companies representing 7 of the 10 Industry Segments as shown in the table on the following pages.

Comments can be reviewed in their original format on the following project page:

http://www.nerc.com/filez/standards/Project2010-11_TPL_Table-1_Order.html

Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text for various reasons and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided including minority opinions such as not allowing Demand interruption at all and has made clarifying revisions to the footnote 'b' text.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ 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:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

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Based on the review of comments received and the fact that only clarifying changes were made due to those comments, the SDT is recommending that this project be moved forward to balloting.

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	Guy Zito	Northeast Power Coordinating Council	10									

	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.	Micahel Schiavone	National Grid	NPCC	1
4.	Sylvain Clermont	Hydro-Quebec TransEnergie	NPCC	1
5.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
6.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
7.	Dean Ellis	Dynegy Generation	NPCC	5
8.	Brian Evans-Mongeon	Utility Services	NPCC	8
9.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3
10.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
11.	Kathleen Goodman	ISO - New England	NPCC	2
12.	Chantel Haswell	FPL Group, Inc.	NPCC	5
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Michael R. Lombardi	Northeast Utilities	NPCC	1

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

15.	Randy MacDonald	New Brunswick System Operator	NPCC	2
16.	Bruce Metruck	New York Power Authority	NPCC	6
17.	Lee Pedowicz	Northeast Power Coordinating Council	NPCC	10
18.	Robert Pellegrini	The United Illuminating Company	NPCC	1
19.	Si Truc Phan	Hydro-Quebec TransEnergie	NPCC	1
20.	Saurabh Saksena	National Grid	NPCC	1

2.	Group	Philip R. Kleckley	SERC Planning Standards Subcommittee	1, 3, 5

Additional Member	Additional Organization	Region	Segment Selection	
1.	Bob Jones	Southern Company Services - Trans	SERC	1
2.	John Sullivan	Ameren	SERC	1
3.	Charles Long	Entergy	SERC	1
4.	Jim Kelley	PowerSouth Energy Cooperative	SERC	1
5.	Pat Huntley	SERC Reliability Corporation		10

3.	Group	Carol Gerou	MRO's NERC Standards Review Subcommittee	10

	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	WPS Corporation	MRO	3, 4, 5, 6
4.	Jason Marshall	Midwest ISO Inc.	MRO	2
5.	Jodi Jenson	Western Area Power Administration	MRO	1, 6
6.	Ken Goldsmith	Alliant Energy	MRO	4
7.	Alice Murdock	Xcel Energy	MRO	1, 3, 5, 6
8.	Dave Rudolph	Basin Electric Power Cooperative	MRO	1, 3, 5, 6
9.	Eric Ruskamp	Lincoln Electric System	MRO	1, 3, 5, 6
10.	Joseph Knight	Great River Energy	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10

11. Joe DePoorter	Madison Gas & Electric	MRO	3, 4, 5, 6
12. Scott Nickels	Rochester Public Utilties	MRO	4
13. Terry Harbour	MidAmerican Energy Company	MRO	1, 3, 5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment
4.	Group	Denise Koehn	Bonneville Power Administration	1, 3, 5, 6

Additional Member	Additional Organization	Region	Segment Selection
1. Chuck Matthews	BPA, Transmission Planning	WECC	1
2. Berhanu Tesema	BPA, Transmission Planning	WECC	1
3. Kyle Kohne	BPA, Transmission Planning	WECC	1
4. Kendall Rydell	BPA, Transmission Planning	WECC	1
5. Rebecca Berdahl	BPA, Long Term Sales and Purchases	WECC	3

Group/Individual		Commenter	Organization	Registered Ballot Body Segment
5.	Group	Louis Slade, Jr.	Dominion	1, 3, 5, 6

Additional Member	Additional Organization	Region	Segment Selection
1. Angela Park	Electric Transmission	SERC	1, 3
2. John Loftis	Electric Transmission	SERC	1, 3
3. Mike Garton	Electric Market Policy	NPCC	5, 6
4. Michael Gildea	Electric Market Policy	RFC	5, 6

Group/Individual		Commenter	Organization	Registered Ballot Body Segment
6.	Group	Ben Li	IRC Standards Review Committee	2

Additional Member	Additional Organization	Region	Segment Selection
1. Bill Phillips	MISO	MRO	2
2. Partick Brown	PJM	RFC	2
3. James Castle	NYISO	NPCC	2
4. Mark Thompson	AESO	WECC	2
5. Charles Yeung	SPP	SPP	2
6. Greg Van Pelt	CAISO	WECC	2
7. Matt Goldberg	ISO-NE	NPCC	2

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
7.	Individual	Jana Van Ness	Arizona Public Service Company	X		X		X					
8.	Individual	Sandra Shaffer	PacifiCorp	X		X		X	X				
9.	Individual	John Cummings	PPL Corp	X		X		X					
10.	Individual	Andy Tillery	Southern Company	X		X							
11.	Individual	Don Gilbert	JEA	X		X		X					
12.	Individual	RoLynda Shumpert	South Carolina Electric and Gas	X		X		X	X				
13.	Individual	Laura Zotter	ERCOT ISO		X								
14.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
15.	Individual	Steve Stafford	Georgia Transmission Corporation	X									
16.	Individual	John Canavan	NorthWestern Energy	X									
17.	Individual	Tim Ponseti	TVA Transmission Planning & Compliance	X		X		X				X	
18.	Individual	Gordon Rawlings	BC Hydro	X	X	X		X					
19.	Individual	Jon Kapitz	Xcel Energy	X		X		X	X				
20.	Individual	John Sullivan	Ameren	X		X		X	X				
21.	Individual	Darcy O'Connell	California ISO		X								
22.	Individual	Doug Hohlbaugh	FirstEnergy	X		X	X	X	X				

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
				1	2	3	4	5	6	7	8	9	10
23.	Individual	Orlando A Ciniglio	Idaho Power	X		X		X					
24.	Individual	Michael Lombardi	Northeast Utilities	X		X		X					
25.	Individual	Thad Ness	American Electric Power	X		X		X	X				
26.	Individual	JC Culberson	ERCOT		X								
27.	Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
28.	Individual	Charles Lawrence	American Transmission Company	X									
29.	Individual	Kathleen Goodman	ISO New England Inc.		X								
30.	Individual	Dan Rochester	Independent Electricity System Operator		X								
31.	Individual	Ed Davis	Entergy Services	X		X		X	X				
32.	Individual	Terry Harbour	MidAmerican Energy	X		X		X	X				
33.	Individual	Patrick Farrell	Southern California Edison Company	X		X		X	X				
34.	Individual	Jonathan Appelbaum	United Illuminating Co	X									
35.	Individual	Michael Moltane	ITC	X									
36.	Individual	Gregory Campoli	New York Independent System Operator		X								
37.	Individual	David Kiguel	Hydro One Networks Inc.	X		X							
38.	Individual	Jason Marshall	Midwest ISO		X								

Group/Individual		Commenter	Organization	Registered Ballot Body Segment									
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39.	Individual	Claudiu Cadar	GDS Associates Inc.	X									
40.	Individual	Chifong Thomas	Pacific Gas and Electric Co.	X		X		X					
41.	Individual	Catherine Koch	Puget Sound Energy	X									
42.	Individual	Harold Wyble	Kansas City Power & Light	X		X		X	X				

1. **The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Orders which required the ERO to clarify TPL-002-0, Table 1 - footnote 'b', regarding the planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.**

Summary Consideration: Industry response was divided in relation to support for the proposed footnote 'b' which was posted for an informal comment period through October 8, 2010. Although there were a number of supporters for the proposed footnote they were outnumbered by the commenters who did not support the footnote text and offered their views and concerns.

The Standard Drafting Team (SDT) carefully considered the feedback provided and has made clarifying revisions to the footnote 'b' text. For each major item, the SDT has addressed the issue raised and has summarized any revision made to footnote 'b' in response to the feedback provided. The SDT appreciates industry input and believes the changes made are responsive to the comments received.

Open and Transparent Process: Most of the comments received related to the use of an "open and transparent" stakeholder process as described in the proposed footnote 'b'. While the comments on this topic varied, the majority of comments indicated that such a process should not be included within a mandatory Reliability Standard and cited that FERC Order 890 already requires the sharing of planning information. Others indicated that the statement for "review and acceptance" exceeds expectations required by FERC Order 890 and that an entity's compliance to a Reliability Standard should not be subject to the "acceptance" of stakeholders and that a process conforming with FERC Order 890 principles already requires dispute resolution. Some commenters expressed support of the process and it is noted that those who responded "Yes" with no comment were assumed to support the process "as is".

The SDT's inclusion of a stakeholder review in footnote 'b' was driven by the fact that FERC Order 890 does not fully cover the continent-wide footprint addressed by a NERC Reliability Standard. Additionally, footnote 'b' is being applied to address localized Bulk Electric System performance and not a wide-area Bulk Electric System concern that is generally the focus of the "open and transparent" process governed by FERC Order 890.

The SDT thoroughly considered all comments on the stakeholder process model. The SDT continues to support a Reliability Standard providing mandatory enforcement utilizing a stakeholder process where any intended use of planned Demand interruption has transparency and that stakeholders have the opportunity to comment on its use. However, upon further reflection the majority of SDT members agreed that including the "acceptance" aspect of the stakeholder process presents challenges within the context of a Reliability Standard and "acceptance" has been removed. The SDT agrees with opinions that an entity's compliance should not be subject to the "acceptance" of its plans by stakeholders. Also, the SDT realizes that for most entities there is a final, high level review with acceptance or approval of Transmission plans at the local level. So, while the footnote no longer references the need for stakeholder acceptance, the expectation is that there will be a review process in place that will consider the implementation of any plan calling for Demand interruption as explained in the footnote.

In addition, the SDT has revised footnote 'b' to explicitly require a response to any challenges presented via the stakeholder process.

Demand vs. Load: Several commenters questioned the SDT's use of the term "Demand" instead of "Load" in the proposed footnote. The SDT clarifies that this was intentional as the existing, approved TPL suite of standards uses the term Demand throughout the requirement text. Additionally, the existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore, for consistency with the existing standard text, the term Demand is retained.

Firm transfer vs. Firm Transmission Service: Some stakeholders suggested that the SDT revert back to the use of "Firm Transmission Service" instead of the undefined term "firm transfers." The SDT clarifies that that the change to "firm transfers" was intentional as the existing, approved TPL suite of standards references "firm transfers" both in requirement text and Table I. The existing, approved TPL performance requirements documented in Table I contain the column heading "Loss of Demand or Curtailed Firm Transfers" which is the subject of the footnote 'b' applicability for category B (single element) Contingencies. This project, Project 2010-11, aims to address footnote 'b' regulatory directives with no change to the remainder of the standard. Therefore for consistency with the existing standard text, the term 'firm transfer' is retained.

Amount of Demand Loss: The majority of commenters agree with the SDT's clarifications regarding interruption of Demand as defined in the proposed footnote 'b'. The majority of entities who commented support the limited use of Demand interruption and that when used to address a BES performance requirement agree that it should be documented, and made known through a stakeholder process. However, as stated above, the majority stopped short of supporting a mandatory Reliability Standard requiring "acceptance" by other entities for the planned interruption of Demand.

Other minority views propose to limit or cap the amount of Demand loss and some suggested 50 MW as the appropriate level. Some felt the SDT's prior approach of limiting the Demand loss to only "radial" line configurations was appropriate and superior to the "open process" approach. It is also noted that some commenters went further to say no loss of Demand should be allowed for a single Contingency, but this was clearly a minority view of the comments submitted.

The SDT carefully considered the comments and unanimously agreed that defining a Demand level limit is problematic based on the vast differences in BES applications across the continent and that each potential use is case specific. The SDT also had concerns that setting such a limit may have the unintended consequences of planned Demand interruption being more widely accepted in practice in Transmission planning. The SDT and most commenters are of the opinion that a stakeholder review process is a better deterrent for Demand interruption and will appropriately guard against any misuse.

The revised footnote 'b' is:

b) An objective of the planning process ~~is to avoid~~ should be to minimize the likelihood and magnitude of interruption of Demand following Contingency events. ~~Interruption of Demand is discouraged and measures to mitigate such interruption should be pursued within the planning process~~. However, it is recognized that Demand ~~may need to~~ 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:

- ~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~
- Interruptible Demand or Demand-Side Management
- ~~Demand that does not adversely impact overall BES reliability where the c~~Circumstances ~~describing~~ where the use of ~~such~~ Demand interruption are documented, including alternatives evaluated; and where the ~~application~~ Demand interruption is subject to review ~~and acceptance~~ in an open and transparent stakeholder process that includes addressing stakeholder comments.

Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.

Organization	Yes or No	Question 1 Comment
Northeast Power Coordinating Council	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that “However, Demand may need to be interrupted in limited circumstances to address BES performance requirements” in the introductory paragraph contradicts bullet 3 “Demand that does not adversely affect BES ...” 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is “accepting”, and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, “would” should be replaced by “must”. Alternatively, possible rewording of footnote “b” to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC

Organization	Yes or No	Question 1 Comment
		Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
Hydro One Networks Inc.	No	1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. Recommend that the drafting team revise the wording to eliminate this implication, and soften the expectation such that it is recognized that some Interruption of Demand is unavoidable by system configuration, but that each entity should establish a reasonable limit on how much demand can be interrupted due to the loss of an element. 2. The Statement that "However, Demand may need to be interrupted in limited circumstances to address BES performance requirements" in the introductory paragraph contradicts bullet 3 "Demand that does not adversely affect BES ..." 3. The third Bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system, documentation expectations, and to answer fundamental questions such as who has the authority to decide the use if the stakeholder process is "accepting", and the necessity of having a stakeholder process. It is unlikely that the interruption of Demand will adversely impact the BES system. This constraint is too broad. The language in this bullet also allows that non-consequential Demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies). 4. In the second paragraph, the conditions when interruption of Firm Transfers may be used are not specified. 5. In the last sentence of the second paragraph, "would" should be replaced by "must". Alternatively, possible rewording of footnote "b" to be considered: b) An objective of the planning process should be to minimize the likelihood of interrupting Demand and measures to mitigate such interruption should be pursued within the planning process. However, Demand may need to be interrupted in limited circumstances to address BES performance requirements or other local reasons which have no adverse impact on overall BES reliability or the interconnected BES. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Demand that does not adversely impact overall reliability of the BES or the interconnected BES and where the circumstances describing the use of such Demand interruption are documented, including alternatives evaluated; and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within

Organization	Yes or No	Question 1 Comment
		applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. The Drafting Team should reconsider the use of "Load" as opposed to "Demand". By definition (NERC Glossary dated April 20, 2010) Demand is:"1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer."Load is defined as:"An end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table.
SERC Planning Standards Subcommittee	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest the following: Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected. " 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."
Ameren	No	The revised text to footnote b relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues rather than on local load serving issues. We suggest the following text for footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Demand or Demand-Side Management o Demand that does not adversely impact overall BES reliability and is made temporarily radial as a result of the Contingency, where that Demand must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the

Organization	Yes or No	Question 1 Comment
		re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected.
MRO's NERC Standards Review Subcommittee	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and maybe subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term, reverting to the “Firm Transmission Service” term, or using another appropriate defined term.
American Transmission Company	No	The revised draft is a significant improvement over the first draft. However, we suggest the following minor changes: 1. The criterion of “adversely affect overall BES reliability” is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest adding the words “as defined by each Transmission Planner or Planning Authority”. 2. The term of “firm transfers” is undefined and may subject to a wide range of interpretation by Transmission Planners, Planning Authorities, and auditors. So, we suggest establishing a definition for the term of "firm transfers", reverting to the “Firm Transmission Service” term, or using another appropriate NERC defined term.
PacifiCorp	No	PacifiCorp believes that the current version of footnote “b” is an improvement over the language that currently exists in the standard, except for one component of the revised footnote. The third bullet in the draft standard currently limits the interruption of Demand if it does not adversely impact overall BES reliability, where the circumstances describing the use of the interruption are documented (including alternatives evaluated) and the application is subject to review and acceptance in “an open and transparent stakeholder process.” PacifiCorp believes that the language requiring review and acceptance of an application of demand interruption through any sort of stakeholder process should be removed. It is not practical or effective to prescribe that either this standard or any other standard requires stakeholder approval in order to maintain compliance. As presently drafted, this requirement for stakeholder review and acceptance appears to be inconclusive and indeterminate as to what is required for registered entities to comply. Instead, this third bullet should require the documentation, by the Planning Authority and Transmission Planner, of the circumstances describing the use of Demand interruption - including methodologies used, assumptions relied upon, and alternatives evaluated - as part of the Planning Authorities’ and/or Transmission Planners’

Organization	Yes or No	Question 1 Comment
		documentation of results in their annual Reliability Assessments. These annual assessments are already submitted to the appropriate Regional Reliability Organization pursuant to TPL-002-1b Requirement R3. This annual assessment can be provided by the ERO to other appropriate third parties upon their request.
Southern Company	No	The revised text relating to the planning process exceeds what is appropriate for a reliability standard. Existing open and transparent stakeholder processes focus on larger system issues and not on local load serving. We suggest that the drafting team go back to the concept of local load being the load that is made temporarily radial by the contingency. That was a much better approach.
JEA	No	The requirement in general is acceptable; however, there needs to be an added "such as" clause to the referenced "...in an open and transparent stakeholder processes." I suggest adding "..."...in an open and transparent stakeholder processes such as the FERC approved regional 890 process that includes the load serving entity affected".
South Carolina Electric and Gas	No	SCE&G believes the first sentence "An object of the planning process is to avoid interruption of Demand." goes beyond what is appropriate for a reliability standard and therefore should be deleted. Also, the part of the sentence that states "and where the application is subject to review and acceptance in an open and transparent stakeholder process" goes beyond what is appropriate for a reliability standard and should be deleted.
NorthWestern Energy	No	In addition to the three bullet items, add a fourth bullet item to the list of limitations under the body of footnote b: "In no case will a total loss of load that is less than 50 MW be considered a violation of this standard."
TVA Transmission Planning & Compliance	No	TVA supports FERC's actions on improving reliability of the BES; however, TVA believes that the new proposal is focusing more on reliability of local loads than on the overall reliability of the BES. Footnote b should focus only on the overall reliability of the BES. Reliability of local loads should be addressed outside the TPL standards and therefore should not be used/referenced in footnote b. Also existing stakeholder processes (referred to in the SDT proposal) typically focus on larger system issues and not on local load serving. Thus TVA believes that some local load should be allowed to be dropped in order to maintain BES reliability. However TVA does believe that there should be a limit of how much load can be dropped in order to maintain BES reliability. TVA believes that 50 MW is a reasonable number for this limit. Based on the above, TVA proposes substituting the following for the revised footnote b:Demand may need to be interrupted in limited circumstances to address BES performance requirements. When interruption of Demand is utilized within the planning process, such interruption is limited to: Demand that is directly served by the elements that are removed from service as a result of the Contingency Interruptible Demand or Demand-Side Management Demand that does not adversely impact overall BES reliability, where that Demand (not to exceed 50 MW)

Organization	Yes or No	Question 1 Comment
		must be interrupted to meet performance requirements. Curtailment of firm transfers is allowed when coupled with the appropriate re-dispatch of resources obligated to re-dispatch where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected.
BC Hydro	No	The SDT is to be commended for their efforts to develop clear, unambiguous language for Footnote "b". From the discussions that have taken place it seems that there are many different perspectives and to get agreement on specific language will be very difficult. We believe that it would be useful to identify the main issues that Footnote "b" needs to address and we consider those main issues to be: o Definitions of (a) Consequential Load Loss, (b) Firm Demand, (c) Firm Transmission Capability (as distinct from the OATT term, "Firm Transmission Service"), (d) Firm Transfer (this could be defined as transfers using the OATT's Firm Transmission Service, (e) Manual System Adjustments (capitalized in the Category C section of TPL-001, but not defined in the NERC Glossary) and (f) the Bulk Electric System (BES). o Identifying permissible Demand/Transfer curtailment actions for (a) the planning studies simulating the Category B event itself and (b) the planning studies associated with determining acceptable actions for preparing for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). This would define the acceptable (pre-emptive) "Manual System Adjustments" of Category C events. o Define separate acceptable curtailment actions for (a) curtailment of Demand (ie, end-user load) and (b) curtailment of market to market transfers, that very rarely, if ever, result in the loss of any end-user load. o Define the planning studies required to determine the acceptability of the impacts on the BES resulting from curtailments in a "remote" part of the system that have been accepted by those directly affected by those curtailments. At this point we don't have specific language to suggest, but we do have the following comments that we hope will help: A. Interruption of Demand: A.1. Consider improving the definition of "Firm Demand" in the NERC Glossary that now reads, "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions". Perhaps it could be changed to something like, "That portion of the Demand that the planned transmission system must be able to supply without interruption for Category B events. A.2. Consider stating in Footnote "b" that curtailment of Firm Demand is (a) not permitted in the simulation of the N-1 event itself and (b) it is not permitted as part of the (pre-emptive) "Manual System Adjustments" needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last

Organization	Yes or No	Question 1 Comment
		several weeks). B. Interruption of Firm Transfers: B.1. “Firm Transfers” could be defined as transfers using the OATT’s Firm Transmission Service, but consider developing a system reliability-based term for “Firm Transmission Capability” instead of referring to the tariff-based NERC definition of “Firm Transmission Service”. This would recognize the difference between planning standards and commercial/tariff rules. The NERC definition of “Firm Transmission Service” is now, “The highest quality (priority) service offered to customers under a filed rate schedule that anticipates no planned interruption”. Transmission tariffs address the priority of curtailments when the loading on a transmission path needs to be reduced for whatever reason (single- or multiple-contingencies). The NERC transmission planning standards need a system reliability definition like, “Firm Transmission Capability” is the transmission capability across a cut-plane, on a defined transmission path or across a defined flowgate that is available, before any manual corrective actions are taken, following the worst Category B event under the most onerous normal system conditions considering all plausible generation dispatch patterns and the full range of expected load levels.” B.2. Consider stating in Footnote “b” that curtailment of Firm Transfers is only permitted to the extent that redispatch of generation can be implemented so that delivery to the Firm Transfer recipient is not interrupted (a) in the planning studies of the Category B event itself and (b) as part of the (pre-emptive) “Manual System Adjustments” needed to prepare for the next set of contingencies should the initial single contingency be prolonged (ie, last several weeks). C. General Comments: C.1. Consider replacing the first bullet of the proposed Footnote “b” with simply “Consequential Load Loss” since the NERC Project 2006 02 (TPL 001) Standard Drafting Team is introducing the following definition: Consequential Load Loss: All Load that is no longer served by the Transmission system as a result of Transmission Facilities being removed from service by a Protection System operation designed to isolate the fault C.2. Consider removing “Demand-Side Management” (DSM) from the second bullet because that term is too general. The present definition of DSM in the NERC Glossary is:”The term for all activities or programs undertaken by Load-Serving Entity or its customers to influence the amount or timing of electricity they use”. C.3. Consider being more specific on what constitutes acceptable “Interruptible Demand”, like: “Interruptible Demand that is part of an automatic real-time Direct Control Load Management (DCLM) system that is activated by the contingencies that require it and that is a completely “dual-redundant” scheme including all communications equipment. The DCLM system must result in automatic curtailment of Demand that is fast enough to maintain all BES system performance standards (eg, voltage stability, voltage dip, etc)”.

Organization	Yes or No	Question 1 Comment
		C.4. Consider eliminating the description of how interrupting Demand that does not adversely impact overall BES reliability was accepted (ie, the stakeholder process, etc). If such a process were undertaken and it resulted in acceptance that the Demand could be curtailed for Category B events, wouldn't that simply mean that the Demand was "Interruptible Demand". It really doesn't matter what process resulted in it being accepted. The key considerations are that (a) if the interruption of that Demand is necessary to maintain BES reliability, then it must be interrupted in a very reliable manner (ie, dual redundant scheme, etc) and (b) if the interruption of that Demand is not necessary to maintain the reliable performance of the BES, then that should be confirmed by the planning studies (ie, it doesn't need to have an expensive, sophisticated, dual-redundant DCLM scheme since the impact on the BES is acceptable even if the scheme doesn't work). D. Additional Questions related to Curtailment of Firm Transfers: In the past, the latter part of Footnote B read: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers."The last part of the proposed Footnote B now reads: "Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions would also be respected."We would like to understand the implications of the proposed Footnote B as it relates to curtailment of Firm Transfers (as per definition proposed earlier) for the following questions: 1) In the most recent draft of Footnote B, why was the NERC defined term 'Firm Transmission Service' replaced with the non-defined term 'firm transfers'? 2) In the most recent draft of Footnote B, why was the tone softened from "No curtailment of Firm Transmission Service is allowed, except..." to "Curtailment of firm transfers is allowed when..."? 3) Assuming an outage of a single transmission line (N-1 Category B event) has occurred and assuming that no "resources [are] obligated to redispatch" for this outage, would a transmission provider be allowed to curtail Firm Transmission Service (NERC defined term) that it has sold in order to prepare to withstand the next worst credible contingency? 4) Would transmission providers be allowed to sell Firm Transmission Service on a path above what could be delivered with any one element of that path out of service and a range of operating conditions? 5) If the proposed Footnote B is approved, would utilities have to reinforce their system (within 60 months) to ensure that Firm Transmission Service for particular paths would not be curtailed can be delivered when any one element of that path is out of service? 6) If a transmission provider employs Generation Dropping for single contingencies in order to support Firm Transmission Service between regions, and assuming there are no provisions for obligated re-dispatch, would

Organization	Yes or No	Question 1 Comment
		the proposed Footnote B force a recalculation of firm vs non-firm transfer capability? 7) Path 66 (PACI) and Path 65 (PDCI) can both see significant derates in their firm transfer capability for single contingencies. How would the proposed Footnote B impact Firm Transmission on these paths?
FirstEnergy	No	FirstEnergy appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. The proposed footnote B is much improved from the prior draft proposals. One change that FirstEnergy proposes is to strike the text following the semicolon in the third bullet item which states "and where the application is subject to review and acceptance in an open and transparent stakeholder process." This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890. We appreciate the SDT's careful consideration of our comments.
Northeast Utilities	No	NU agrees with the language of the proposed revision to Footnote b EXCEPT FOR bullet #3 which suggests that non-consequential demand interruption could be used to mitigate reliability violations arising from the NERC Category B contingency events (i.e., single element contingencies).
ERCOT	No	The introductory paragraph of footnote b includes policy language. Since this is a reliability standard-and not a policy directive-the general narrative setting forth the desired policy goal of minimizing load-shedding is misplaced. Including policy language can cloud the specific issues the standard attempts to address, and ERCOT recommends deleting the first two sentences in the introductory paragraph. The next sentence in the introductory paragraph goes on to state, generally, that demand may be interrupted to "address BES performance requirements." This phrase is vague. To which performance requirements does this refer? The intent is not clear. If the intent is to generally recognize the need to shed load to respect

Organization	Yes or No	Question 1 Comment
		NERC standards and to allow flexibility for an entity to exercise discretion relative to meeting BES performance requirements, then that intent should be clearly reflected in the language. Furthermore, the last sentence of the introductory paragraph and the subsequent bullet points are arguably inconsistent with this approach, because they could be viewed as removing an entity’s flexibility/discretion by limiting the circumstances when load can be shed. The second bullet point is unnecessary, because it is already apparent that interruptible demand/demand side management programs can be used according to their terms. This could create confusion in that it could be implied that, absent the need to use these to meet BES performance requirements, using them otherwise is inconsistent with/not allowed under footnote b. Simply put, those products are not load shedding as contemplated by this footnote. Therefore they should not be listed here. With respect to the third bullet point, the phrase "demand that does not adversely impact overall BES reliability" is not adequately defined, and provides opportunity for confusion. This is an ambiguous phrase and can’t be linked back to objective NERC standards/requirements. The bullet points should avoid ambiguity to mitigate ambiguity risk in audits. In addition, the last part of the language in this bullet imposing an open and transparent stakeholder process is unclear. What is the intent behind requiring review in a stakeholder process? If it is to establish the ability of the entity to develop load shedding procedures beyond those explicitly contemplated in footnote b, ERCOT questions if it is reasonable for the responsible entity to be required to get “permission” from stakeholders to implement reliability measures related to its obligation as the functional entity. Again, the language simply is not clear. Accordingly, ERCOT recommends this bullet point be removed. If it is retained, it should be revised consistent with these comments to remove ambiguous language to mitigate potential confusion around the meaning/scope of the footnote in the administration of the CMEP. In addition, ERCOT recommends revising the draft footnote b to allow for planned Demand interruption as a means of mitigation during interim periods when a unanticipated (such as unexpected demand growth or unit retirements) or temporary change on the system occurs in a timeframe that is shorter than the time necessary to plan and implement the system upgrades necessary to avoid the Demand interruption. Finally, in the last paragraph of footnote b, it isn’t clear why “Transmission Service” was changed to “transfers.” Firm transmission service is a service provided in some regions, and it provides relative value to other types of services-e.g., non-firm and network. The mention of transmission service may also be irrelevant in this footnote, since the allowance of its interruption doesn't also allow for load shedding. Therefore, ERCOT recommends eliminating the last paragraph of footnote b.
ISO New England Inc.	No	ISO New England does not allow non-consequential load loss for first contingencies in Planning Analysis, and as an overall matter, ISO-NE believes that the appropriate step is for NERC to modify the footnote in line with

Organization	Yes or No	Question 1 Comment
		the original FERC Order. However, ISO-NE offers the following recommendation to improve the proposed language for footnote b if it is to be retained similar to what has been proposed. In short, ISO-NE proposes changing the third sub-bullet, because the provision is both unnecessary and inappropriate for a NERC Standard. First, the sub-bullet is redundant, because the Commission has ordered that companies add to their Open Access Transmission Tariffs an open and transparent planning process. If Transmission Planners establish their system planning assessments through those processes, then there should be no question that the Planner’s assessments have been effectively communicated to the region. Second, the passive nature of the language (i.e., “where the application is subject to review and acceptance...”) is unclear as it suggests that someone other than the Planning Coordinator/Transmission Planner is responsible for determining what belongs in a long-term system assessment. Including Demand-Side Management in the standard also appears redundant as Demand Response is used as an asset in the same manner as generation resources. b) When interruption of Demand is utilized within the planning process, such interruption is limited to: 1) Demand that is directly served by the elements that are removed from service as a result of the Contingency. 2) Interruptible Demand or Demand-Side Management 3) Instances where the planned or controlled interruption of Demand results in System performance which meets the requirements of Table 1 for Category B contingencies. When such Demand interruption is utilized in an assessment, the use of such actions must be limited to small portions of the system, be operationally achievable, be of limited duration, and be documented therein.
Entergy Services	No	Entergy disagrees with the proposed language in the third bullet for two reasons. 1. While Entergy supports the idea of “an open and transparent stakeholder process” regarding the use of non-consequential load loss. It is unclear how such a process could be fairly implemented as competing stakeholder interests could prevent resolution. Stakeholders should be defined as those stakeholders whose load could be shed per footnote b, not any and all stakeholders. 2. The “is subject to review and acceptance” implies that some formal voting process would be required by stakeholders. Is this the SDT’s intent? If so would such a process be developed as part of the standard or would it be left up to TO’s? If non-consequential load loss was deemed an acceptable solution across a SEAM, would the TO’s jointly serving the load need to agree?

Organization	Yes or No	Question 1 Comment
MidAmerican Energy	No	While the TPL note “b” approach has improved, MidAmerican has concerns that including the wording “review and acceptance” goes beyond the FERC Order 890 order, process, and intent of including the open review process. Therefore, to align with FERC Order 890, the “review and acceptance” should be replaced with “subject to comment”. Anything more exceeds FERC Order 890 and the reason why the review process was included. In the end, Transmission Owning and Operating entities must have final say in the operation of the grid. Entities can comment, but cannot obstruct Transmission Owning and Operating entities from properly operating the grid or reliability could be reduced.
United Illuminating Co	No	United Illuminating believes that for TPL Category B contingencies no planned or controlled (non-consequential) interruption of firm demand should occur as a general philosophy for planning the Bulk Electric System (BES). Recognizing there are certain areas of the BES that have unique circumstances that may warrant an exception to this, UI suggests the addition of language that recognizes the limited application of non-consequential load interruption with a process that requires a case-by-case acceptance of such application by the Regional Entity or NERC.
New York Independent System Operator	Yes	The NYISO agrees in principle with the proposed changes, but recommends the following modifications: 1. The introductory paragraph discourages the Interruption of any Demand, implying that no Demand directly connected should be interrupted. However, it is an acceptable practice to allow for some Interruption of Demand that is directly connected to the element that is removed from service. The introductory paragraph is immaterial to the requirement, and therefore unnecessary with the exception of the last sentence which starts the bulleted list. 2. Interruptible demand is an operation tool and not a transmission planning tool, while Demand-Side Management is typically embedded in the load forecast used in the planning process. The second bullet therefore may not be necessary or applicable here, though it is helpful in making clear those are acceptable forms of interruption. 3. The third bullet is confusing. Suggest revising the wording to clarify the adverse impact to the BES system and documentation expectations. Recommend removing reference to the application being subject to review and acceptance in an open and transparent stakeholder process; this is inherent to all documentation and does not need to be emphasized in a footnote. 4. In the last sentence of the last paragraph, “would” should be replaced by “must”. 5. The Drafting Team should reconsider the use of “Load” as opposed to “Demand”. By definition (NERC Glossary dated April 20, 2010) Demand is: 1. The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time. 2. The rate at which energy is being used by the customer.”Load is defined as:”An

Organization	Yes or No	Question 1 Comment
		end-use device or customer that receives power from the electric system."This terminology is more appropriate to the application used in the Table. Possible rewording of footnote "b" to be considered: b) Under the limited circumstances when interruption of Load is utilized within the planning process to address BES performance requirements, such interruption is limited to: o Load that is directly served by the elements that are removed from service as a result of the Contingency o Interruptible Load or Demand-Side Management o Demand that does not adversely impact overall BES reliability where the circumstances for the use of such Load interruption and alternatives evaluated are documented. Curtailment of firm transfers is allowed, when coupled with the appropriate re-dispatch of available resources, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any firm Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions must also be respected.
Midwest ISO	No	Overall, we believe the changes are reasonable. However, we propose to strike "and where the application is subject to review and acceptance in an open and transparent stakeholder process." Stakeholder review processes should not be mandated through enforceable standards as they do not provide a clear benefit to reliability. Further, FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system.
GDS Associates Inc.	No	We appreciate all the work conducted by SDT to adjust current footnote "b" however, we disagree with the current approach as follows below:- The definition does not go far enough with recognition that interruption of Demand should be mitigated if at all possible. The previous language may have been inadequate, but the current language does not encourage the TP to develop mitigation plans that could be implemented as an alternative to Demand interruption. - Use of Interruptible Demand should only be implemented if the Transmission Planner can point to a contract between the Transmission Provider and Transmission Customer that permits load curtailment .- Under FERC Order 890, Conditional Firm transmission service can be granted for entities who voluntarily acknowledge the right of the Transmission Provider to curtail their transaction or provide re-dispatch. This should be the only transfer which can be utilized in the Planning Horizon for interruption of Demand for Note b. Suggested language to find the balance point in the tone of this note is below:"An objective of the planning process is to develop mitigation plans that do not call for the curtailment of Demand, as interruption of Demand places specific customer groups at a reliability risk that varies from their counterparts in other areas of the BES. There may be rare instances, however, where interruption of Demand can be considered a short-term bridge to a mitigation plan which does not rely on negatively impacting certain customer segments. When interruption of Demand is utilized within the planning process, such interruption is limited to: o Demand that is directly served by the elements that are removed from service as a result of the Contingency, o

Organization	Yes or No	Question 1 Comment
		Interruptible Demand or Demand-Side Management, where the Customer has given explicit rights to the Transmission Provider for curtailment of their Demand, o Demand, other than Interruptible Demand or Demand-Side Management, that does not adversely impact overall BES reliability where the circumstances describing the use of such Demand are documented, including alternatives evaluated; where the Load-Serving Entity who has responsibility for serving such Demand has agreed to the curtailment, and where the application is subject to review and acceptance in an open and transparent stakeholder process. Curtailment of Firm transfers is allowed, when coupled with the appropriate re-dispatch of resources obligated to re-dispatch per the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider, where it can be demonstrated that Facilities remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of and firm Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions would also be respected. In addition, any Conditional Firm transfers may be curtailed, in accordance with the terms and conditions of the confirmed transmission service request between the Transmission Customer and Transmission Provider.”
Kansas City Power & Light	No	KCPL appreciates the efforts of the Assess Transmission Future Needs SDT in reaching a reasonable proposal for clarifying Table 1 footnote B presented in the TPL-001 through TPL-004 standards. We also commend NERC staff for convening an industry technical conference to discuss the topic and FERC staff for their participation in the technical conference as the industry carefully considered various perspectives. Although the proposed footnote B is much improved from the prior draft proposals, KCPL proposes is to strike the text following the semicolon in the third bullet item which states “and where the application is subject to review and acceptance in an open and transparent stakeholder process.” This text may be intended as explanatory but has the appearance of mandating an approval process that will be auditable through the TPL reliability standards. The statement is not needed within the framework of mandatory reliability requirements as FERC Order 890 already mandates an open and transparent process related to the planning of the bulk electric system. FERC via the 890 Final Rule modified the pro forma Open-Access Transmission Tariff to require open and transparent stakeholder process to better ensure no undue discrimination and access to the transmission system. The Final Rule beginning at paragraph 418 discusses reform to the Coordinated, Open and Transparent Planning of the transmission system. The Commission direction included eight planning principles required to be within the open process - one of which is dispute resolution. It should be well understood that the transmission planner and planning coordinator share and disseminate all of their planning study results and proposed corrective actions - including the proposed use of Demand interruption - as part of their adherence to Order 890.
Puget Sound Energy	Yes	PSE agrees with the foot note b as stated. As it states for any category B outage there wouldn't be any non-consequential load loss allowed unless a full study is performed with evaluation of alternatives and is approved by stakeholders. Also, one could curtail firm transfers if re-dispatch of resource is possible.

Organization	Yes or No	Question 1 Comment
		However, there is still some ambiguity in when approval from stakeholders (time-line) should be sought and who the stakeholders could be (customers, effected utilities etc.). Hence, PSE would like to revise the footnote by adding the following to the end of the footnote, ".... at least 2 years prior to the implementation. All the affected parties must review and agree upon the loss of demand proposal."
Southern California Edison Company	Yes	SCE appreciates the efforts of the NERC Standards Drafting Team and believes that the team has admirably worked to meet FERC's expectations.SCE would suggest that Footnote "b" be revised to include a semi-colon(;) after the first sub-paragraph and a semi-colon(;) followed by an "and" after the second sub-paragraph, to convey that the three sub-paragraphs are alternative, rather than additive methods for satisfying the requirements for "interruptions."
Idaho Power	Yes	footnote 'b' is silent with respect to planned removal from service of certain generators. I believe there are many conditions out there where a single contingency can initiate a planned (RAS-initiated) removal of generation. The fact that this is mentioned in footnote 'c', under multiple contingencies, begs the need for futher elaboration/discussion of this option under single contingencies in footnote 'b'.
Manitoba Hydro	Yes	The changes to Table 1 Note b proposed by the SDT for this second posting are a reasonable approach to the issue of interrupting of “Firm Demand”. The requirement to evaluate alternatives to dropping of Firm Demand in a transparent stakeholder process should provide the verification of cost over benefit on a case by case basis. I propose the following editorial changes: 1. The change of “Firm Transmission Services” made in Table 1 should be also be made in each TPL standard as R1 refers to “projected Firm (non-recallable reserved) Transmission Services.2. Since “Firm Demand” is a defined term, ensure it is capitalized throughout the standard. There is one instance where it is not.
California ISO	Yes	1) Regarding the 2nd bullet provision, we suggest: Interruptible Demand or Demand-Side Management that has been reviewed and approved by the Planning Authority. 2) Regarding the 3rd bullet provision, we suggest: Demand interruption that does not adversely impact overall BES reliability.... 3) Also regarding the 3rd bullet provision, we suggest replacing acceptance with clarification to read “where the application is subject to review and clarification in an open and transparent stakeholder process."
Xcel Energy	Yes	Xcel Energy supports the new interpretation that would allow curtailment of firm transfers or demand for limited conditions where the integrity of bulk electric system is not compromised. However Xcel Energy seeks some clarification regarding the following: The 3rd bullet point in footnote b will need to clarify whether the demand interruption can be done after the contingency, or before the contingency. If it is allowed after the

Organization	Yes or No	Question 1 Comment
		contingency, then the standard would allow violation of voltage or thermal loading criteria for a brief period, after contingency and, before demand curtailment happens. Is this acceptable based on the new interpretation? Since TPL-002 standard deals with NERC Category B contingencies, and footnote b states that curtailment of firm transfers is allowed, it should be clarified if this curtailment is allowed before or after the contingency. If the curtailment is allowed only after the contingency, then the system would be in violation of the thermal or voltage criteria for a brief period till the generation is re-dispatched. Is this allowed by the new interpretation? If curtailment is only allowed in preparation of the contingency, then the firm transfers would be curtailed during system intact conditions, in preparation for the first contingency, resulting in violation of TPL-001 standard. Is this allowed by the new interpretation?
PPL Corp	Yes	PPL believes that Footnote b as described in TPL-002-1b, Draft 2, August 30, 2010 is fine provided an accompanying Requirement (with appropriate VRF and VSL) and Measure is added to the TPL standard(s) to require and document notification of the affected Demand parties and the involvement of the affected Demand parties in an open process as described by Footnote b, third bullet.
Duke Energy	Yes	Duke Energy strongly supports this revised footnote 'b'. We believe that it provides for appropriate consideration of stakeholder input in decision-making for local reliability issues, while maintaining the reliability of the Bulk Electric System.
ITC	Yes	The proposed language for the new TPL-001-1 Table 1 footnote b is acceptable to ITC.
Bonneville Power Administration	Yes	
Dominion	Yes	
IRS Standards Review Committee	Yes	
IRC Standards Review Committee	Yes	
Arizona Public Service Company	Yes	
ERCOT ISO	Yes	

Organization	Yes or No	Question 1 Comment
Georgia Transmission Corporation	Yes	
American Electric Power	Yes	
Independent Electricity System Operator	Yes	
Pacific Gas and Electric Co.	Yes	