NERC
NORTH AMERICAN ELECTRIC RELIABILITY CORPORATION

Consideration of Comments on Project 2010-11: TPL Table 1 Order and Comments Submitted with Initial Ballots

The Standards Committee thanks all commenters who submitted comments on the proposed SAR for the TPL Table 1 Order. The SAR proposed changes to TPL Table 1 in response to FERC's Order RM06-16-009 which requires 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 by June 30, 2010. Table 1 is used in TPL-001, TPL-002, TPL-003, and TPL-004 – and any change to Table 1 needs to be reflected in all four of these TPL standards.

The SAR, implementation plan, and the clean and redline versions to the four TPL standards were posted for a 40-day public comment period from April 15, 2010 through May 27, 2010. Stakeholders were asked to provide feedback on the standards through a special electronic comment form. There were 22 sets of comments, including comments from more than 80 different people from approximately 40 companies representing 8 of the 10 Industry Segments as shown in the table on the following pages.

The initial ballot for the proposed changes to the four TPL standards was conducted from May 17-27, 2010. The comments submitted with initial ballots and the drafting team's responses to those comments are also contained in this report.

All comments submitted during the comment period and the initial ballot results are posted on the following page:

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

Based on stakeholder comments, the drafting team has made some additional changes to Footnote 'b' in Table 1 of TPL-001, TPL-002, TPL-003, and TPL-004. The changes include the following:

Stakeholders identified that the terminology used in Footnote 'b' didn't match the terminology used in the associated column heading of Table 1 – 'Loss of Demand or Curtailed Firm Transfers.' For additional clarity, the team made the following terminology changes:

- The term 'Load' was replaced with 'Demand'
- The term 'Firm Transmission Service' was replaced with 'firm transfers'

The following bullet was added to Footnote 'b' to provide the flexibility requested by stakeholders with respect to interrupting Demand, but with appropriate constraints to protect reliability. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the loading on a high capacity 161 kV transmission line is approximately 50 MW.

- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

The following bullet was added to Footnote 'b' to clarify that it is acceptable to use Interruptible Demand and Demand-Side Management:

- Interruptible Demand or Demand-Side Management

The above changes will be noted to stakeholders before the initiation of the recirculation ballot.

The revised Footnote 'b' is:

b) No interruption of projected customer Demand is allowed except:

- Interruption of Demand that is directly served by the elements that are removed from service as a result of the Contingency
- Planned or controlled interruption of Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

If you feel that your comment has been overlooked, please let us know immediately. Our goal is to give every comment serious consideration in this process! If you feel there has been an error or omission, you can contact the Vice President and Director of Standards, Gerry Adamski, at 609-452-8060 or at gerry.adamski@nerc.net. In addition, there is a NERC Reliability Standards Appeals Process.[1]

[1] The appeals process is in the Reliability Standards Development Procedures: http://www.nerc.com/standards/newstandardsprocess.html.

Comments and Responses from Formal Comment Period:

Comments and Responses from Initial Ballot:

The Industry Segments are:

1 — Transmission Owners
2 — RTOs, ISOs
3 — Load-serving Entities
4 — Transmission-dependent Utilities
5 — Electric Generators
6 — Electricity Brokers, Aggregators, and Marketers
7 — Large Electricity End Users
8 — Small Electricity End Users
9 — Federal, State, Provincial Regulatory or other Government Entities
10 — Regional Reliability Organizations, Regional Entities

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

	Additional Member	Additional Organization	Region	Segment Selection
1.	Alan Adamson	New York State Reliability Council	NPCC	10
2.	Greg Campoli	New York Independent System Operator	NPCC	2
3.	Roger Champagne	Hydro-Quebec TransEnergie	NPCC	2
4.	Kurtis Chong	Independent Electricity System Operator	NPCC	2
5.	Sylvain Clermont	Hydro-Quebec TransEnergie		1
6.	Chris de Graffenried	Consolidated Edison Co. of New York, Inc.	NPCC	1
7.	Gerry Dunbar	Northeast Power Coordinating Council	NPCC	10
8.	Ben Eng	New York Power Authority	NPCC	4
9.	Brian Evans-Mongeon	Utility Services	NPCC	8
10.	Mike Garton	Dominion Resources Services, Inc.	NPCC	5
11.	Brian L. Gooder	Ontario Power Generation Incorporated	NPCC	5
12.	Kathleen Goodman	ISO - New England	NPCC	2
13.	David Kiguel	Hydro One Networks Inc.	NPCC	1
14.	Peter Yost	Consolidated Edison Co. of New York, Inc.	NPCC	3

	Commenter	Organization	Industry 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. Saurabh Saksena		National Grid	NPCC					1				
20. Michael Schiavone		National Grid	NPCC					1				
2. Group	Philip R. Kleckley	South Carolina Electric & Gas	X		X		X					
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Bob Jones		Southern Company Services - Trans.	SERC					1				
2. David Marler		Tennessee Valley Authority	SERC					1				
3. Charles Long		Entergy	SERC					1				
4. James Manning		North Carolina Electric Membership Corporation	SERC					3				
5. Pat Huntley		SERC Reliability Corporation	SERC					10				
3. Group	John Bee	Exelon Transmission Strategy & Compliance	X		X		X					
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Mortenson, Eric		:(ComEd)	RFC					1				
2. Weaver, David W		(PECO)	RFC					1				
3. McHugh, Kathleen P		(PECO)	RFC					1				
4. Kay, Thomas W		(ComEd)	RFC					1				
5. Szymczak, Ronald		(ComEd)	RFC					1				
6. Chu, Ron F		(PECO)	RFC					1				
7. Donnelly, Michael J		(PECO)	RFC					1				
8. Kliros, Chris B		(ComEd)	RFC					1				
9. Mills, Paul M		(ComEd)	RFC					1				
10. Webb, Becky		(ComEd)	RFC					1				
4. Group	Denise Koehn	BPA, Transmission Reliability Program	X		X		X	X				

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Chuck Matthews		BPA, Transmission Planning	WECC					1				
2. Berhanu Tesema		BPA, Transmission Planning	WECC					1				
3. Larry Furumasu		BPA, Transmission Planning	WECC					1				
4. Kyle Kohne		BPA, Transmission Planning	WECC					1				
5. Don Watkins		BPA, Transmission System Operations	WECC					1				
6. Rebecca Berdahl		BPA, Power, Long Term Sales and Purchases	WECC					3				
5.	Group	Carol Gerou	Midwest Reliability Organization									X
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Chuck Lawrence		American Transmission Company	MRO					1				
2. Tom Webb		Wisconsin Public Service	MRO					3, 4, 5, 6				
3. Terry Bilke		Midwest ISO Inc.	MRO					2				
4. Jodi Jenson		Western Area Power Administration	MRO					1, 6				
5. Ken Goldsmith		Alliant Energy	MRO					4				
6. Dave Rudolph		Basin Electric Power Cooperative	MRO					1, 3, 5, 6				
7. Eric Ruskamp		Lincoln Electric System	MRO					1, 3, 5, 6				
8. Joseph Knight		Great River Energy	MRO					1, 3, 5, 6				
9. Joe DePoorter		Madison Gas & Electric	MRO					3, 4, 5, 6				
10. Scott Nickels		Rochester Public Utilities	MRO					4				
11. Terry Harbour		MidAmerican Energy Company	MRO					1, 3, 5, 6				
6.	Group	Richard Kafka	Pepco Holdings, Inc.	X		X		X	X				
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Jim Summers		Delmarva Power and Light Co.	RFC					1				
2. John Radman		Potomac Electric Power Company	RFC					1				
7.	Group	Ben Li	IESO		X							
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				

	Commenter	Organization	Industry Segment									
			1	2	3	4	5	6	7	8	9	10
1. Bill Phillips		MISO	MRO									
2. James Castle		NYISO	NPCC									
3. Charles Yeung		SPP	SPP									
4. Lourdes Estrada-Salinero		CAISO	WECC									
5. Patrick Brown		PJM	RFC									
6. Steve Myers		ERCOT	ERCOT									
8. Group	Frank Gaffney	Florida Municipal Power Agency	X			X	X	X				
Additional Member		**Additional Organization**	**Region**					**Segment Selection**				
1. Timothy Beyrle		Utilities Commission of New Smyrna Beach	FRCC					4				
2. Greg Woessner		Kissimmee Utility Authority	FRCC					1				
3. Jim Howard		Lakeland Electric	FRCC					1				
4. Lynne Mila		City of Clewiston	FRCC					3				
5. Joe Stonecipher		Beaches Energy Services	FRCC					1				
6. Cairo Vanegas		Fort Pierce Utility Authority	FRCC					4				
9. Individual	Stephen Mizelle	Southern Company Transmission	X									
10. Individual	Robert Casey	Georgia Transmission Corporation (Bulk System Planning)	X									
11. Individual	Thad Ness	American Electric Power	X		X		X	X				
12. Individual	Kasia Mihalchuk	Manitoba Hydro	X		X		X	X				
13. Individual	Martin Bauer	US Bureau of Reclamation					X					
14. Individual	Kirit Shah	Ameren	X		X		X	X				
15. Individual	Robert W. Roddy	Dairyland Power Cooperative	X		X		X					

		Commenter	Organization	Industry Segment									
				1	2	3	4	5	6	7	8	9	10
16.	Individual	Marty Berland	Progress Energy	X		X		X	X				
17.	Individual	Michael R. Lombardi	Northeast Utilities	X		X		X					
18.	Individual	Charles Lawrence	American Transmission Company	X									
19.	Individual	Greg Rowland	Duke Energy	X		X		X	X				
20.	Individual	Bill Middaugh	Tri-State Generation and Transmission Association, Inc.	X		X		X	X				
21.	Individual	Roger Champagne	Hydro-Québec TransEnergie (HQT)	X									
22.	Individual	Dan Rochester	Independent Electricity System Operator		X								

1. The SDT is proposing a revision to footnote 'b' in the TPL tables to comply with FERC Order RM-06-16-009 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 by June 30, 2010. Do you agree with the proposed changes and if not, please provide specific reasons for your disagreement.

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

To match the terminology in the revised footnote with the terminology in the associated column heading (Loss of Demand or Curtailed Firm Transfers) the term, 'Load' was replaced with 'Demand' and the term 'Firm Transmission Service' was replaced with 'firm transfers.'

Footnote 'b' now reads:

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed~~, except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Duke Energy	No	Duke Energy voted "Negative" on the initial and current ballots of TPL-001-1, primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL).The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency

Organization	Yes or No	Question 1 Comment
		and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex. b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Midwest Reliability Organization	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
Dairyland Power Cooperative	No	DPC concurs with the MRO comments: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.
American Transmission Company	No	For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant

Organization	Yes or No	Question 1 Comment
		transmission system modifications.
Response: The SDT has added the fourth bullet to address your concern. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Georgia Transmission Corporation (Bulk System Planning)	No	Georgia Transmission Corporation (GTC) believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We believe that FERC's directive in (Docket No. RM06-16) to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view

Organization	Yes or No	Question 1 Comment
		to allow loss of non-consequential load.We also note that on April 19 NERC filed a request for rehearing with FERC asking that the Commission revise the directive in Paragraph 8 of the March 18 TPL-002 Order to allow NERC the necessary time to incorporate changes to the TPL-002 Reliability Standard through the Reliability Standards Development Process that are necessary to achieve bulk power system reliability. NERC also requested that the Commission grant NERC's Motion for Stay to stay the Order so that a public technical conference with opportunity for comment can be held in order to provide parties an opportunity to meet and discuss the technical considerations of developing a modification to the TPL-002 standard that prohibits the loss of non-consequential firm load in the event of an N-1 contingency. NERC's April 19 filing pointed out that if the Commission's directive to disallow the loss of non-consequential firm load for an N-1 contingency is implemented, a question is presented regarding whether the Reliability Standard still serves the purpose of ensuring the Reliable Operation of the bulk power system by preventing instability, uncontrolled separation, and cascading failures. That is, the Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Progress Energy	No	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new

Organization	Yes or No	Question 1 Comment
		footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner/Operator. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered:"No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 1 Comment
Hydro-Québec TransEnergie (HQT)	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Northeast Power Coordinating Council	No	The proposed changes do not adequately address FERC's concerns in RM06-16-009. The Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." The proposed changes to footnote 'b' indicate "No interruption of firm Load is allowed except:... (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities." The exception described appears to still allow non-consequential load loss. FERC describes in RM06-16-009 non-consequential load loss as "the removal, by any means, of any firm load that is not directly served by the elements that are removed from service as a result of the contingency." In referencing Order 693, the Commission reiterated its position that TPL standards "should not allow an entity to plan for the loss of non-consequential load in the event of a single contingency." "Must" should be used instead of "should" in the last sentence of the footnote, making it to read "Facility Ratings in those regions must also be respected."
Response: The SDT believes that it has been responsive to the FERC directive in that the standards development process has been employed. In the		

Organization	Yes or No	Question 1 Comment
development of the footnote, the SDT has balanced the need for discretion while addressing local area concerns with the need to assure the reliability of the BES. 'Must' is not appropriate in a footnote as it would impose a requirement in the footnote. The SDT has replaced 'should' with 'would' to correct the grammar. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed~~, except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Tri-State Generation and Transmission Association, Inc.	No	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "...where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might also fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region."
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:		

Organization	Yes or No	Question 1 Comment
		o (1) Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o (2) Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Southern Company Transmission	No	We propose that the section in double parentheses be deleted. The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal.((Planned or controlled interruption of electric supply to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, may occur in certain areas without impacting the overall reliability of the interconnected transmission systems. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers.)) No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers No curtailment of Firm Transmission Service is allowed except when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. where it can It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.

Organization	Yes or No	Question 1 Comment
Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
South Carolina Electric & Gas	Yes	For better clarity delete the phrase "when coupled with" in the second paragraph of footnote 'b.'
Response: The SDT did not delete the suggested phrase as it believes it is correct as stated but added commas to make the phrase read more clearly. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~		

Organization	Yes or No	Question 1 Comment
		o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Independent Electricity System Operator	Yes	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows:"As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighboring systems, and associated equipment, generally operated at voltages of 100 kV or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.		
BPA, Transmission Reliability Program	Yes	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Response: The SDT agrees and has made the change. b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW		

Organization	Yes or No	Question 1 Comment
		o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed~~,~~ ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
American Electric Power	Yes	
Exelon Transmission Strategy & Compliance	Yes	
Florida Municipal Power Agency	Yes	
IESO	Yes	
Northeast Utilities	Yes	
Pepco Holdings, Inc.	Yes	
US Bureau of Reclamation	Yes	
Manitoba Hydro	Yes	MH agrees with the SDT proposal.
Ameren	Yes	We were ok with the previous language. Though we do not intend to drop non-consequential load for a single contingency, we undersatnd that other ares may have been following such practice without degarding the relaibility of BES. We believe that they can continue this practice if they develop non-firm contracts with these customers.
Response: Thank you for your support.		

2. Are you aware of any conflicts caused by compliance with the proposed language in Table 1 — footnote b and any regulatory function, rule order, tariff, rate schedule, legislative requirement or agreement? If yes, please identify the conflict.

Summary Consideration: The SDT understands that there may be conflicts as pointed out by respondents; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch do~~es~~ not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Organization	Yes or No	Question 2 Comment
Ameren	No	
American Electric Power	No	
American Transmission Company	No	
BPA, Transmission Reliability	No	

Organization	Yes or No	Question 2 Comment
Program		
Dairyland Power Cooperative	No	
Exelon Transmission Strategy & Compliance	No	
Independent Electricity System Operator	No	
Manitoba Hydro	No	
Midwest Reliability Organization	No	
Southern Company Transmission	No	
US Bureau of Reclamation	No	
South Carolina Electric & Gas	No	The comments expressed herein represent a consensus of the views of the above named members of the SERC Engineering Committee Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board or its officers.
Response: Thank you for your response.		
Hydro-Québec TransEnergie (HQT)	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.
Northeast Power Coordinating Council	Yes	Conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.

Organization	Yes or No	Question 2 Comment
IESO	Yes	It should be noted that conflicts may arise between individual state commissions, who may have rate recovery authority, and utilities who attempt to abide explicitly with FERC's position on non-consequential load loss. In RM-06-16-009, the Commission again references Order 693 and specifically highlights comments by Duke Power Company and Northern Indiana Public Service Company by saying the arguments made to date to allow non-consequential load loss after a single contingency event is "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." In the US, State commissions with rate recovery authority may take the position that considering the economics of proposed investments intended to prevent non-consequential loss of small or remote load is acceptable. This potential conflict between state and federal positions could place utilities in a compromising position.Similar conflicts may also exist in Canada.
Progress Energy	Yes	There is the potential for conflict between Table 1 - Footnote (b) as currently proposed, which can be considered to regulate local distribution reliability without improving BES reliability, and local service reliability issues which are under the purview of state regulatory agencies. For example, the North Carolina Utilities Commission (NCUC) commented regarding this concern in the ballot which ended March 1 in Project 2006-02. Specifically, NCUC commented that they were "...concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1 is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions..." Progress Energy believes that NCUC's concerns are legitimate. BES reliability should address the avoidance and mitigation of cascading outages and BES facility damage, rather than limited, controlled local area loss of load, in order to avoid this conflict and overlap of regulation.
Response: The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		
Northeast Utilities	Yes	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern.		

Organization	Yes or No	Question 2 Comment
b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.		
Duke Energy	Yes	See response to question #1.
Georgia Transmission Corporation (Bulk System Planning)	Yes	See response to Question #1.
Response: See response to question #1.		
Florida Municipal Power Agency	Yes	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Pepco Holdings, Inc.	Yes	This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this

Organization	Yes or No	Question 2 Comment
		has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Response: Thank you for your support.		
Tri-State Generation and Transmission Association, Inc.	Yes	We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT is not in a position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.		

3. Consideration of Comments on Initial Ballot — TPL Table 1 Order (Project 2010-11) May 17–27, 2010

Summary Consideration: The SDT has listened to the comments from the industry, understands the concerns raised, and has made changes to the footnote to balance the various industry concerns while assuring BES reliability.

The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. This is limited by two conditions: >90% demand level and 50 MW. The >90% demand level was selected to ensure that the number of hours with exposure to demand loss was not unlimited. A 90% demand level is a reasonably stressed case for most systems and the number of hours when peak demands are >90% is a small percentage of the time for most systems. A large percentage of the transmission lines that directly serve distribution customers are 161 kV or lower voltages. Ten percent (10%) of the demand on a high capacity 161 kV transmission line is approximately 50 MW.

A 4th bullet has also been added to clarify that it is acceptable to use Interruptible demand and Demand-Side Management.

The second paragraph of the footnote has been clarified and references Firm Transfers now instead of Firm Transmission Service.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Rodney Phillips	Allegheny Power	1	Negative	Allegheny Power believes the loss of non-consequential load and/or curtailment of transmission service for N-1 contingencies should be limited to only extreme circumstances. Exception 2 of footnote b allows for the loss of non-consequential load for N-1

Voter	Entity	Segment	Vote	Comment
				contingencies with no restriction. Allegheny Power recommends removing exception 2 footnote b.
Response: The SDT and the majority of the commenters disagree with this suggestion.				
Gordon Rawlings	BC Transmission Corporation	1	Negative	BCTC appreciates the good work of the SAR committee in drafting the changes to Footnote b of Table 1. BCTC agrees with the drafting team that interruption of firm load, served by either radial circuits or circuits that have became radial as a result of the contingency, should be allowed for N-1 contingencies. However, it is our position that interruption of firm load should not be limited only to such consequential loads. In our view, interruption of electric supply to some local network customers in the affected area should be permissible. This inclusion will allow transmission planners to plan BCTC's regional transmission network reliably and without impacting neighbouring transmission networks.
Faramarz Amjadi	BC Transmission Corporation	2	Negative	
Hubert C. Young	South Carolina Electric & Gas Co.	3	Negative	SCE&G has significant concern with the proposed revision to TPL Table 1, Footnote B. The current Footnote B states "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". The phrase "without impacting the overall reliability of the interconnected transmission systems" is important to the TPL standards to ensure that ERO standards do not dictate the level of service to customers. Service to customers and load pockets is jurisdictional to State Commissions and ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must retain the concept that planned or controlled interruption of electric supply to customers, whether they are radial or network, is allowed as long as it does not impact the overall reliability of the interconnected transmission systems. The proposed revision eliminates this concept. There seems to be a general inconsistency and maybe confusion between the terms "reliability" and "level of service".
David Frank Ronk	Consumers Energy	4	Negative	The current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the previous version of TPL-001-1. However, it still does not allow Transmission Planners to use appropriate and necessary discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should control the decision making when BES reliability is not an issue. Often, the consequences of these events are solely local in nature, requiring only minor additional loss of local load to
James B Lewis	Consumers Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
				avoid the costly major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Hugh A. Owen	Public Utility District No. 1 of Chelan County	6	Negative	The interruption of a small amount of load is, under most conditions, not a risk to the reliability of the BES and is at times necessary to preserve reliability. The planned interruption of some load may be a cost effective alternative to a costly transmission project. That is a quality of service issue.
Michael Gammon	Kansas City Power & Light Co.	1	Negative	While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load.
Charles Locke	Kansas City Power & Light Co.	3	Negative	
Thomas Saitta	Kansas City Power & Light Co.	6	Negative	
Linda Brown	San Diego Gas & Electric	1	Affirmative	As to item (1), all load served directly by a transmission element which experiences a fault will be interrupted when the faulted element is taken out of service. This is the natural relationship between the load and the transmission element. Allowing this for BES elements may encourage transmission owners to remove transmission instead of upgrading or replacing it. Consider a load supplied by two transmission lines of different capacity. If the larger line is lost due to a contingency (N-1) and the remaining smaller line overloads the transmission owner is left with several options to address the problem: (1) move load between buses, (2) upgrade the smaller line, (3) add another line, or (4) create a radial load by removing the smaller line. Number (4) may be the least expensive and allowable under TPL-002, footnote b. Item (2) may also encourage transmission owners to develop plans which make load shedding part of category B. Consider a load served by three transmission lines, a utility may decide to remove a line, instead of upgrading, in order to set up a situation where an N-1 contingency would make the bus temporarily radial. In the event of a single outage (N-1), the load bus will be temporarily radial and load can be shed at the bus.

Voter	Entity	Segment	Vote	Comment
W. R. Schoneck	Florida Power & Light Co.	3	Affirmative	I believe the language is an improvement and clarifies the intent but I believe there still should be additional language added to give an exemption in meeting this requirement if it does not make economic sense(not economically feasible) and has no real impact on the BES.
Richard J Kafka	Potomac Electric Power Co.	1	Affirmative	It is understood that this is a compliance filing issue. This is not an issue for historic PJM members, but as PJM has expanded and as a result of the merger of historic councils into RFC, I am aware that not all regions had standards equal to those of MAAC, and this has been an issue worked out between transmission planners (historic transmission owners) and their local regulators. It is ultimately a cost issue for loss of local load that does not affect the overall reliability of the interconnected BES.
Alan Gale	City of Tallahassee	5	Affirmative	TAL thanks for SDT for the tireless effort to get to this point. TAL is voting affirmative with the following comments. We accept that the loss of non-consequential load is not a desired result for N-1 contingencies. It is also not the norm in system planning or operations. The flexibility to operate the system consistent with "good utility practice" may warrant the "odd-ball" case that would require this to occur. The dropping of non-consequential load will NOT lead to BES instability, voltage collapse, or cascading outages, which is what FERC and NERC are charged with preventing. It will lead to the shedding of load in a local area only. Utilities do not drop customers lightly. If the meter isn't turning, we are not getting paid, so we want the meter spinning. Utility power, while vital to our normal day-to-day lives and infrastructure, was never intended to be without interruption.
Brad Chase	Orlando Utilities Commission	1	Affirmative	This change raises the bar on transmission system performance. This change applies a blanket requirement upon entities that does not take into account the number of outages, probability of outages or cost to the customer. There are certain to be situations where this blanket requirement will result in increased cost to customers for no noticeable increase in reliability. OUC does agree with the concept of greater clarification on this requirement, however this clarification may raise the bar to far by trying to establish a blanket requirement. Duke, Progress Energy and others will be submitting comments with proposed language that attempt to address some of these issues and we encourage the drafting team to consider those comments.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate				

Voter	Entity	Segment	Vote	Comment
constraints. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Eric Egge	Black Hills Corp	1	Negative	Black Hills believes that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.

Voter	Entity	Segment	Vote	Comment
Chifong L. Thomas	Pacific Gas and Electric Company	1	Negative	PG&E commends the SDT for developing the proposed footnote b. While it is a great improvement over the complete prohibition on loss of non-consequential load for any single contingency, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system, especially where the impact is local in nature, to avoid instability, cascading or uncontrolled separation. Such planned interruption of load may be a reasonable alternative to the environmental impacts or prohibitive costs associated with a major new transmission project. Given the potential impacts of the proposed modification, further vetting of the issues is needed. PG&E believes that NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Thomas J. Bradish	RRI Energy	5	Negative	RRI supports the WECC position on this issue; namely, that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Trent Carlson	RRI Energy	6	Negative	

Voter	Entity	Segment	Vote	Comment
John Tolo	Tucson Electric Power Co.	1	Negative	The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project.
James Tucker	Deseret Power	1	Negative	The prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
Louise McCarren	Western Electricity Coordinating Council	10	Negative	The proposed revisions to footnote b of Table 1 are an improvement to the recently balloted prohibition on loss of non-consequential load for single contingencies. The recognition of the new term "temporarily radial" is a step in the right direction. However, the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their

Voter	Entity	Segment	Vote	Comment
				individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
William Mitchell Chamberlain	California Energy Commission	9	Negative	While the proposed revisions to footnote b are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, the prohibition of loss of non-consequential load for events resulting the loss of a single element still inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. NERC should be allowed to hold a public technical conference, as described in NERC's April 19, 2010, request for rehearing before being required to develop and submit clarifications to footnote b of Table 1.
John Mick	Colorado Springs Utilities	6	Negative	Colorado Springs Utilities ballot on the proposed changes to TPL Table 1, footnote b directed in FERC Order RM06-16-009 Colorado Springs Utilities wishes to vote NO on the proposed changes to TPL Table 1, footnote b, directed in FERC Order RM06-16-009. CSU concurs with the WECC position paper for the ballot, and agrees with the WECC statement "that the prohibition of loss of non-consequential load for events resulting in the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues".
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.				

Voter	Entity	Segment	Vote	Comment
The SDT agrees that a technical conference on this issue would be of value. b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Horace Stephen Williamson	Southern Company Services, Inc.	1	Negative	Comments have already been submitted previously, but it will be added here again. Proposed footnote should read... No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities. To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power transfers when coupled with the appropriate re-dispatch of resources obligated to re-dispatch. It must be demonstrated that Facilities remain within applicable Facility Ratings and those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. The proposed changes are based on the
Richard J. Mandes	Alabama Power Company	3	Negative	
Anthony L Wilson	Georgia Power Company	3	Negative	

Voter	Entity	Segment	Vote	Comment
Gwen S Frazier	Gulf Power Company	3	Negative	following... "The proposed wording by the drafting team seems to imply that the curtailment of firm transmission service is permitted to address single contingency constraints if coupled with the redispatch of network resources. The original language stated only that curtailments were permitted to prepare for the next contingency, not to address loading related to the initial contingency. The proposed wording could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint. Southern Companies recommend that the original language relating to "preparing for the next contingency" be incorporated into the drafting team's proposal."
Don Horsley	Mississippi Power	3	Negative	
Michael Ibold	Xcel Energy, Inc.	3	Negative	The proposed modification to footnote b of Table I in TPL-001 - 004 standards states that after a Category B contingency, there should not be any thermal, voltage or stability violation, no interruption of firm load (except the load that is directly connected to the elements that are removed from service as a result of the contingency) and no firm transfer curtailment (except when coupled with re-dispatch of resources obligated to re-dispatch). We believe the proposed footnote b creates a gap between TPL-002 and TPL-003 standards, since it does not address conditions when firm load shedding and firm transfer curtailments are not required to meet the system performance for Category B contingency, but one or both are the required system adjustments to prepare for the next contingency (Category C3). When firm transfer is curtailed after the first contingency in preparation for the next contingency, it is not clear from the proposed footnote b if this is considered a valid system adjustment for Category C or a violation of Category B. Recall that the existing footnote b addresses this condition explicitly by stating "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm Transfers."
Liam Noailles	Xcel Energy, Inc.	5	Negative	
David F. Lemmons	Xcel Energy, Inc.	6	Negative	
George T. Ballew	Tennessee Valley Authority	5	Affirmative	TVA appreciates the work of the SDT on this issue. However, TVA recommends revising the second paragraph of the revised footnote b: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers. However, curtailment of Firm Transmission Service is only 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 those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility
Marjorie S. Parsons	Tennessee Valley Authority	6	Affirmative	

Voter	Entity	Segment	Vote	Comment
				Ratings in those regions should also be respected." Without the changes in the first two sentences above, the proposed wording by the SDT could be interpreted to allow re-dispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.
Larry Akens	Tennessee Valley Authority	1	Affirmative	TVA appreciates the work of the SDT. However, TVA recommends revising the second paragraph of the revised footnote "b". Without changes in the first two sentences, the proposed wording by the SDT could be interpreted to allow redispatch/firm curtailments to address any single contingency constraint instead of in preparation for the next contingency.

Response: The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Robert W. Roddy	Dairyland Power Coop.	1	Negative	DPC CONCURS WITH THE MRO COMMENTS.
Jason Shaver	American Transmission Company, LLC	1	Affirmative	For Footnote b, add a third exception to the list, “or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed if the tripping of the load is either accepted or volunteered by the customer.
Lawrence R. Larson	Otter Tail Power Company	1	Negative	The change precludes the use of direct load control systems that should be allowed to relieve transmission problems. These systems control firm transmission load but rate conditions can allow their use to mitigate transmission problems.

Response: *(Note - MRO did not submit comments with the initial ballot – but did submit the following comment during the formal comment period: For Footnote b, add a third exception to the list, "or (3) end-use load that is either accepted or volunteered by the customer". It is a widely-held understanding that the tripping of non-consequential, end-use load is also allowed, if the tripping of the load is either accepted or volunteered by the customer in lieu of significant transmission system modifications.)*

The SDT has added the fourth bullet to address your concern.

b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner’s planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Ajay Garg	Hydro One Networks, Inc.	1	Negative	Hydro One is casting a negative vote for the following reasons: 1. The amendment to the footnote does not add any technical value to the standard. It was added only to satisfy a FERC directive to address comments made to allow non-consequential load loss after a single contingency event, "based largely on the matter of economics, not reliability, with the underlying premise that it is not economically feasible to invest in the bulk electric system to the point that it can continue service to all firm load customers under some specific N-1 scenarios." 2. Addressing curtailment of Firm Transmission Service with re-dispatch of resources is a matter of a commercial nature and should be dealt with in the agreements dealing with such services. Issues of contracted transmission services, firm or otherwise, are not a reliability related matter and are not to be dealt with in this standard. 3. Matters of interruption of firm load should be incorporated into this standard only after the FERC NOPR on the definition of the BES is resolved. As it stands, the footnote will pose significant problems if the 100 kV and above FERC proposal is applied across the board, unless the standard specifically states that it applies to the BES as defined by the region (current definition).
Michael D. Penstone	Hydro One Networks, Inc.	3	Negative	
Response: 1. & 2. The SDT disagrees – there is a direct impact on reliability of the BES associated with these concerns. The SDT has added clarity to the footnote by designating constraints for Demand and firm transfer curtailment. 3. The SDT disagrees that this needs to wait on the FERC NOPR. This standard is applicable to the BES as it is defined.				
Spencer Tacke	Modesto Irrigation District	4	Negative	I am voting NO vote because of the lack of clarity of the second paragraph of the proposed change. Although paragraph 1 is an improvement to the current wording, and actually allows for some specific flexibility in shedding load for an N-1 event, the lack of clarity in the second paragraph could lead to varied interpretations by members and compliance auditors. Thank you.
Response: The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:				

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Dana Cabbell	Southern California Edison Co.	1	Negative	It is SCE's position that the planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. When planned load interruption is identified as a response to a single event, the impact to the system is often local in nature. The planned interruption of load may be a desirable alternative to the prohibitive costs associated with a major new transmission project. If the NERC Standards Drafting Team decides to proceed with footnote B, as written, it needs to ensure that Transmission Owners, Transmission Operators, and Transmission Planners have enough time to both design and implement any mitigation plans necessary to be compliant with the new language. In almost all cases the actual implementation of a solution requiring new construction will be dependent on a number of different regulatory agencies providing the necessary permits allowing for its construction. As such, NERC needs to ensure that any time frame associated with compliance to the proposed language be variable, and allow for extended implementation time frames based on system conditions that may delay placing mitigation plans in service. An example of a reasonable variable time frame to be compliant with the proposed language in footnote B would be to start the clock 60 months from receiving the pertinent environmental permitting. In
David Schiada	Southern California Edison Co.	3	Negative	
Ahmad Sanati	South California Edison Company	5	Negative	

Voter	Entity	Segment	Vote	Comment
				California this could be the issuance of a Draft Environmental Impact Review pursuant to the California Environmental Quality Act.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT has added more latitude for the Transmission Planner with the addition of the 3rd bullet and believes that 60 months should be sufficient.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Voter	Entity	Segment	Vote	Comment
Henry Ernst-Jr	Duke Energy Carolina	3	Negative	On the initial ballot of TPL-001-1 Duke Energy also voted "Negative", primarily because Duke believes that the requirement prohibiting loss of non-consequential load for P1, P2.1 and P3 events is an overreach by the standard into local load quality of service issues. We also sought rehearing on the Commission's March 18 Order Setting Deadline for Compliance (Docket No. RM06-16), with respect to this and other issues. We believe that FERC's directive in that Order to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. While the current revised footnote b is an improvement from the prohibition on loss of non-consequential load associated with the recently balloted version of TPL-001-1, it still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, customers, and local regulators should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the potential impacts (environmental, historical, archaeological, aesthetic...) of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. With this "Negative" vote, Duke offers the following ideas on alternatives for the SDT to consider that will allow for appropriate discretion and facilitate proper planning while allowing non-consequential load loss (NCLL). The standard should allow for dropping of limited amounts of non-consequential load in situations where it would be reasonable for a bounded time period and under restricted system conditions (e.g. 1-3 years only when load is >90 % of peak conditions). Dropping of non-consequential load would be prudent planning in situations where the near term impact of load projections or implementation of nearby transmission/generation projects will alleviate the necessity of an upgrade to meet N-1 conditions. Also, reliability of service to end-use customer is impacted by the entire system

Voter	Entity	Segment	Vote	Comment
				from source to load. Where allowance for NCLL would not greatly impact individual end-use customers' level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to avoid projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics (e.g. SAIFI/SAIDI/ASAI) should also be considered by the SDT for determination of acceptable use of NCLL.
Luther E. Fair	Gainesville Regional Utilities	1	Affirmative	Even though I am voting in the affirmative, I agree that most of the comments offered by Duke and Norther Indiana in their earlier statements have merit and should be considered. Also, I believe that the use of reliability metrics should be considered by the SDT for determination of acceptable use of NCLL.
Mace Hunter	Lakeland Electric	3	Negative	Reliability should consider the entire system from source to load. Where allowance for NCLL would not greatly impact individual end-use customer's level of reliability the transmission planner should consider its use. Normally transmission system outages are a minor contributor to overall customer outage frequency and duration. Instances where allowance for NCLL can be used to delay projects without greatly impacting a customer's outage frequency and duration should be acceptable. Use of reliability metrics should also be considered by the SDT for determination of acceptable use of NCLL.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT discussed the use of reliability metrics for providing flexibility to planners but has not included their use as this would make the implementation too complex.

> b)–No interruption of ~~firm Load~~ projected customer Demand is allowed except:

Voter	Entity	Segment	Vote	Comment
				o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Sammy Roberts	Progress Energy Carolinas	1	Negative	Progress Energy applauds NERC's efforts to improve the footnote (b) language with respect to conditional allowance of curtailing Firm Transmission Service, which is addressed in the second paragraph of the proposed new footnote (b). PE remains concerned, however, that the first paragraph of the proposed new footnote (b) does not allow for curtailment of non-radial non-consequential load. The ability to curtail non-consequential load in the planning horizon can be a useful tool to mitigate local area issues, and has not been detrimental to the Bulk Electric System (BES). Disallowing the curtailment of non-radial non-consequential load essentially prohibits taking action in situations in which the load in question is clearly at a localized self-contained level of the system, i.e. the distribution system(s) served by the Transmission Owner. Prohibiting the curtailment of local load thus constitutes regulating distribution feeder reliability rather than BES reliability. Events that could be mitigated through the curtailment of local, non-radial non-consequential load are infrequent, and such curtailment has no material effect on the reliability of the BES. PE therefore suggests that the following addition (item (3)) to the first paragraph of the proposed footnote (b) be considered: "No interruption of firm Load is allowed except: (1) Interruption of Load that is directly served by the elements that are removed from service as a result of the Contingency, and/or (2) Planned or controlled interruption of Load supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities, and/or (3) Planned or controlled interruption of any additional Load required to mitigate the post-contingency results, provided that the non-
Lee Schuster	Florida Power Corporation	3	Negative	
Sam Waters	Progress Energy Carolinas	3	Negative	
Wayne	Progress Energy	5	Negative	

Voter	Entity	Segment	Vote	Comment
Lewis	Carolinas			consequential load being shed for the event is localized, and provided that the total load shed for the event does not exceed 2% of the Planned system peak demand or 200 MW, whichever value is less."

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT did adopt a limit but felt that 2% of system peak or 200 MW was not equitable for all entities.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW
- Interruptible Demand or Demand-Side Management

~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Timothy VanBlaricom	California ISO	2	Negative	The California ISO supports NERC's request for a public technical conference to be held, as described in NERC's April 19, 2010 request for rehearing and motion for stay of the March 18 Order (RM06-16-009), to provide the opportunity to gain industry input and written comments regarding the Commission's TPL-002-0 directive for NERC to develop a modification to the TPL-002-0 Table 1 footnote b.

Response: The SDT agrees that a technical conference would be of value.

Voter	Entity	Segment	Vote	Comment
Terry L. Blackwell	Santee Cooper	1	Negative	The Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning processes appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load. Table B footnote still does not allow Transmission Planners to use appropriate discretion regarding loss of non-consequential load. Transmission Planners, and local customers should jointly control the decision making when BES reliability is not an issue. Often, the events are extremely improbable and the consequences of these events are local in nature, only requiring minor additional loss of local load to avoid the cost of major projects. In many instances, it may be in the best interest of all involved parties from an overall cost/benefit point of view to allow loss of non-consequential load. The Commission's directive sets forth an expectation that NERC is to implement standards that address all loss of load at costs that may not be commensurate with bulk power system reliability, as statutorily defined, which is fundamentally different from what the Reliability Standards were intended to do.
Zack Dusenbury	Santee Cooper	3	Negative	
Suzanne Ritter	Santee Cooper	6	Negative	
Response: The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				
Kimberly J. Jones	North Carolina Utilities Commission	9	Negative	The NC Utilities Commission is concerned that the requirement prohibiting loss of non-consequential load for events in Table 1 of TPL-001-1, and as explained in draft footnote b, is an inappropriate overreach into service issues that are more appropriately addressed by state regulatory commissions. This requirement does not provide any benefit to reliability of the bulk electric system and could undermine state efforts to balance reliability issues with cost of service issues. The standard should continue to allow Transmission Planners to use discretion regarding loss of non-consequential load, understanding that state commissions are positioned to force electric utilities to address local service quality issues on an expedited basis, should it be necessary and in the public interest.
Response: The SDT understands the concern but believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.				

Voter	Entity	Segment	Vote	Comment
James L. Jones	Southwest Transmission Cooperative, Inc.	1	Negative	THE PROPOSED INTERPRETATION WILL UNDERMINE THE INTERNATIONAL STANDARDS SETTING PROCESS AND COULD RESULT IN DIFFERING INTERPRETATIONS OF STANDARDS ON THE NORTH AMERICAN BULK-POWER SYSTEM.
Response: The SDT disagrees and believes that the footnote has been clarified appropriately within the standards development process.				
Daryn Barker	Louisville Gas and Electric Co.	6	Negative	The revised footnote b on Table 1 imposes additional requirements on the responsible entities. The footnote states: Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Charlie Martin	Louisville Gas and Electric Co.	5	Negative	Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected. However, R1 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is planned These statements address different and inconsistent scope. If the change in scope was intended then a change should also be made to R1 to reconcile the inconsistency.
Response: The SDT agrees that your assessment is for your portion of the interconnected grid. However, when performance in one system is dependent on generation dispatch in another system or vice versa, the SDT believes that one must ensure that the re-dispatch is feasible. The SDT does not believe that this presents a conflict with Requirement R1.				
John Apperson	PacifiCorp	3	Negative	This proposal warrants a "no" vote due to the current uncertainty regarding the outcome of the FERC TPL-002 NOPR issued by FERC on March 18, 2010. The impacts of the proposed changes to footnote B cannot be assessed separately from the alternative interpretation of TPL-002 proposed by FERC. The proper planning of a transmission system requires that all performance requirements are known and understood. If only some of the requirements are known and understood it is impossible to properly plan, study, assess, and operate the transmission system.

Voter	Entity	Segment	Vote	Comment
Response: The current TPL-002 is in force and will remain so until the completion of the cited FERC NOPR. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				
Keith V. Carman	Tri-State G & T Association Inc.	1	Negative	Tri-State does believe that the new footnote is an improvement, but thinks there are still some changes necessary. We believe that the word "only" should be removed from the phrase "…where that Load must be interrupted to meet performance requirements only on those now radial Transmission Facilities" because that discrimination was not required in FERC Order RM-06-16-009. There may be times when facilities near the temporary radial facilities might fall outside the limits set in reliability criteria but the situation is mitigated if the load shedding occurs at the radial facility. The meaning of the second paragraph of the new footnote is unclear. Tri-State recommends changing it to "Curtailment of Firm Transmission Service is not allowed unless it is coupled with curtailment-offsetting resources that are obligated to re-dispatch. Further, the curtailment activities cannot result in the shedding of any Firm load or in violations of Facility Ratings, either internal or external to the planning region." We believe that FERC's directive in FERC Order RM-06-16-009 to prohibit the loss of non-consequential load in the event of a single contingency appears to extend beyond measures needed for "reliable operation" of the bulk-power system to prevent "instability, uncontrolled separation or cascading failures," none of which occur when utilities implement a planned and orderly loss of non-consequential load. Hence, the Commission's directive to prohibit utilities from incorporating carefully controlled loss of non-consequential load into their planning protocols appears to extend the Commission's reach beyond its review of measures that are needed for "reliable operation" of the bulk-power system as defined under Section 215 of the Federal Power Act. Such directive constitutes an overreaching of the Commission's jurisdiction under Section 215 of the Federal Power Act into the jurisdiction of state commissions which generally have responsibility for overseeing quality of service issues applicable to local load.
Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. Instead of removing the word 'only', the 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.				

Voter	Entity	Segment	Vote	Comment
				b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The SDT is not in position to comment on FERC's authority. The SDT understands the issue; however, the SDT believes that there should be constraints on the amount of Demand that can be tripped for single Contingencies to assure the reliability of the BES.
Claudiu Cadar	GDS Associates, Inc.	1	Negative	We do not agree with the proposed changes due to several reasons. Although the proposed change will directly influence the reliability standards and transmission system performances, will also have an indirect impact on the economic side with respect to the expansion of existing transmission system. We believe that FERC directive as stipulated in Order 693 cannot constrict, nor impose certain actions outside of the reliability limits. We believe that since these events are merely isolated and rarely enforced, the decision of mandating a great financial effort as a consequence of the proposed changes would certainly be counterbalanced by its feasibility when compare with the current cost of load shedding. While the revised footnote b can be certainly considered an improvement from the current version, however it still does not allow the joined entities involved to have power over the decision making when BES reliability is not an issue. We also believe that any mandatory changes implemented in the TPL standards under the current scenario are not entirely feasible unless all other issues such as the definition of the

Voter	Entity	Segment	Vote	Comment
				BES, Consequential / Non-consequential Load, BES Critical Element, etc gets resolve ahead. The revision with respect to load shedding, specifically the portion about shedding loads on newly radial facilities, does not match the version 1 TPL standard definition of consequential load loss. To approve the proposed revision to footnote 'b' would create an unnecessary discrepancy between the version 1 TPL standard under consideration and the existing standards. We recognize that the Version 1 will replace Version 0, but since it appears that the performance standard with respect to footnote 'b' is intended to be same in the revised footnote and the Version 1 standard, it only makes sense that the revised version 0 footnote 'b' match the consequential load loss definition contemplated in Version 1. In the light of the above we suggest the Commission to approach different other solutions and ideas for improving the current reliability of the transmission system without enforcing decisions beyond its statutory scope. We advance an alternative to this matter meant to balance the reliability of the transmission system and its indirect financial impact. Although the solution that we offer would require an extended time for development and implementation, however we urge NERC to consider it in its further approach. Our alternative consists mainly in implementing an additional term such as "Critical Load" which we have briefly figured that would consist in particular load necessary to be maintained in service without interruption. Even though this new term would seemed to be at first related with the quality of the service, however a joint association of transmission planners, customers, regulatory entities as decision makers can simply individualize the load that cannot be shed, as well as future transmission improvements that will be required to serve this envisioned small amount of load rather than the entire load. In this way we will create a reasonable balance in between the reliability of the transmission system and the cost to maintain / improve this reliability.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

> b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:
>
> o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~

Voter	Entity	Segment	Vote	Comment
				o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected. The current TPL-002 is in force and will remain so for the forseeable future. This limited scope revision to footnote 'b' is to add clarity to what is in effect. Project 2006-02 is under revision and the clarifications of footnote 'b' will be considered by the SDT for future revisions of TPL-001-2. The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability.
Ronald D. Schellberg	Idaho Power Company	1	Negative	While the proposed revisions are an improvement to the prohibition on loss of non-consequential load for a single contingency proposed in the recently failed TPL-001-1 ballot, that the prohibition of loss of non-consequential load for events resulting the loss of a single element inappropriately reaches beyond the reliability of the bulk power system to local load quality of service issues. However, the removal of: "To prepare for the next contingency, system adjustments are permitted, including curtailments of contracted Firm (non-recallable reserved) electric power Transfers." will require significant adjustments in either TRM or TTC reductions to be compliant with this revised standard in the WECC Region. To construct additional transmission facilities to maintain present day business could easily exceed 10 Billion dollars throughout the WECC region. For example, the Pacific AC Intertie currently has a TTC of 4800 MW spread across 3 500 kV transmission lines. With the loss of one Transmission line, the Pacific AC intertie drops to 3200 MW. Removal of this sentence would require TP either to drop the Firm TTC of the Intertie to 3200, or include a TRM reservation of at least 1600 MW. The TPs would not be able to say that a loss of 1600 MW of import capacity would not result in curtailments of firm load. Just about all multi

Voter	Entity	Segment	Vote	Comment
				transmission line paths in the WECC Region would suffer. The planned and controlled interruption of a small amount of load, under certain conditions, is not a risk to reliability or an indication of an unreliable system, but rather, serves to preserve the reliability of the bulk power system. Transmission Planners and Planning Coordinators should be given the discretion to determine whether or not the planned and controlled interruption of load is an appropriate system response to certain contingencies, taking into consideration all factors, including customer and local regulator input, for their individual system. Often times when planned load interruption is identified as a response to a single event, the impact to the system is local in nature. The planned interruption of load may be the alternative to prohibitive costs associated with a major new transmission project. In the case of long interties between subregions of WECC, these interties have never been planned to operate in this manner. Idaho Power recommends that the sentence permiting system adjustments be reinserted into Footnote B.

Response: The SDT has listened to the comments from the industry, understands the concerns raised, and has made a change to the footnote to balance the various industry concerns while assuring BES reliability. The 3rd bullet has been added to provide the flexibility requested by industry with appropriate constraints.

The SDT believes that System re-dispatch is an acceptable System adjustment to "remain within applicable Facility Ratings" to address loading issues that result from single Contingencies. As drafted, paragraph 2 of footnote 'b' clarifies that re-dispatch is allowable to "remain within" ratings, not to bring the Facilities within ratings. The draft language recognizes that System adjustments may be required after a single Contingency, since entities may utilize ratings in the planning horizon that can be only be utilized for a limited time, such as a 2 hour emergency rating. Paragraph 2 clarifies that if an entity is obligated to re-dispatch its generation resources, the Transmission Planner can plan to re-dispatch those resources for a single Contingency. However, if the resources that impact the affected Facilities are not obligated to re-dispatch, the Firm Transmission Service cannot be curtailed. Therefore, the SDT does not believe that it is necessary to add the words "To prepare for the next Contingency" to the paragraph. The SDT made editorial changes to the 2nd paragraph to provide additional clarity in response to your comment and those of others.

b) No interruption of ~~firm Load~~ projected customer Demand is allowed except:

- ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~
- ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~
- Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW

Voter	Entity	Segment	Vote	Comment
				o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
Francis J. Halpin	Bonneville Power Administration	5	Affirmative	For consistency, regarding the firm transfer issue, the term "Firm Transmission Service" should be replaced with "Firm Transfers" in order to be consistent with the fourth column of the existing Table 1 "Transmission System Standards - Normal and Emergency Conditions".
Response: The SDT agrees and has made the change. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				
Kim Warren	Independent Electricity System Operator	2	Affirmative	IESO supports the revisions made to footnote 'b' based on the present definitions of BES and Firm Demand and on the understanding that the NERC standards apply only to the BES as defined in the NERC Glossary as follows: "As defined by the Regional Reliability Organization, the electrical generation resources, transmission lines, interconnections with neighbouring systems, and associated equipment, generally operated at voltages of 100 kV

Voter	Entity	Segment	Vote	Comment
				or higher. Radial transmission facilities serving only load with one transmission source are generally not included in this definition." To be clear, our interpretation of the present definition of BES is that it defers to each Regional Reliability Organization to define the elements of the power system that are considered BES and, therefore in the NPCC Region, "BES as defined by NERC" = "BPS as defined by NPCC".
Response: The SDT agrees that the standard applies to the BES as defined in the Glossary.				
Jacquie Smith	ReliabilityFirst Corporation	10	Affirmative	If this revision is an urgent action, then the implementation timeframe should be shorter. In the clarification paragraph below, I do not understand the first sentence. Are there commas missing? What is the requirement and what is the exception? Also, I question the validity of using "should" in the second sentence. If it is a requirement, then it needs to be stated as a requirement. If it is a suggestion, then it does not belong in the standard. No curtailment of Firm Transmission Service is allowed except 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 those adjustments do not result in the shedding of any firm Load. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions should also be respected.
Response: This has not been classified as an 'urgent action'. Commas have been added as appropriate and a re-wording was made which should make this clear. 'Should' has been replaced by 'would' to provide additional clarity. b) No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels				

Voter	Entity	Segment	Vote	Comment
				greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.
David H. Boguslawski	Northeast Utilities	1	Affirmative	Northeast Utilities (NU) believes the language of the proposed revision to footnote 'b' can be better defined as the proposed revision is subject to interpretation by the different entities and regulatory agencies. Future conflicts can be minimized by further clarifying the proposed revision. Also, NU is concerned that this new modification does not specify the amount of permissible load shed nor does it require the planning entity to minimize load shedding under this exception.
Response: The SDT has made several clarifying changes to the footnote which should alleviate your concerns. The SDT has modified the footnote for clarity and added constraints in new bullet 3 to address your specific concern. b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except: o ~~(1)~~ Interruption of ~~Load~~Demand that is directly served by the elements that are removed from service as a result of the Contingency~~, or~~ o ~~(2)~~ Planned or controlled interruption of ~~Load~~Demand supplied by Transmission Facilities made temporarily radial as a result of the Contingency and where that ~~Load~~Demand must be interrupted to meet performance requirements only on those now radial Transmission Facilities~~.~~ o Planned or controlled interruption of Demand required to address post-Contingency performance issues that occur at Demand levels greater than 90% of forecasted Peak Demand provided that the Demand being interrupted does not exceed 50 MW o Interruptible Demand or Demand-Side Management ~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.				

Voter	Entity	Segment	Vote	Comment
Donald S. Watkins	Bonneville Power Administration	1	Affirmative	On the firm transfer issues, the term "Firm Transmission Service" should be replaced with "Firm Transfers" to be consistent with the fourth column of the existing Table 1 Transmission System Standards - Normal and Emergency Conditions.
Rebecca Berdahl	Bonneville Power Administration	3	Affirmative	
Brenda S. Anderson	Bonneville Power Administration	6	Affirmative	

Response: The SDT agrees and has made this change.

b) ~~–~~No interruption of ~~firm Load~~ projected customer Demand is allowed except:

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~~No c~~Curtailment of ~~Firm Transmission Service~~ firm transfers is allowed, ~~except~~ 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 ~~those adjustments~~ the re-dispatch does not result in the shedding of any firm ~~Load~~Demand. Where Facilities external to the Transmission Planner's planning region are relied upon, Facility Ratings in those regions ~~should~~would also be respected.

Frank Gaffney	Florida Municipal Power Agency	4	Affirmative	Please see FMPA comments submitted through the concurrent comment period for Project 2010-11
David Schumann	Florida Municipal Power Agency	5	Affirmative	

Voter	Entity	Segment	Vote	Comment
Response: Please see the response to FMPA comments above.				
Carter B Edge	SERC Reliability Corporation	10	Affirmative	The footnote makes clearer when load can be dropped for planning purposes. By making this footnote more specific, it supports reliability and helps stakeholders apply the TPL standards.
Timothy Beyrle	City of New Smyrna Beach Utilities Commission	4	Affirmative	This is an area of fuzziness between State jurisdiction and Federal jurisdiction. In all honesty, shedding load for local area impacts has nothing to do with BES reliability and should not be under FERC jurisdiction under Section 215 of the Federal Power Act, but rather State jurisdiction for quality of service issues. However, there is also the matter of FERC jurisdiction over commercial matters and the opportunity to "game" the original footnote by transmission providers by allowing firm load shedding to grant firm transmission service for themselves, thereby avoiding or deferring transmission investment, while at the same time denying or requiring others to build the same transmission avoided in order to obtain transmission service. We can see how difficult it is from a drafting team's perspective in achieving a balanced position between these different matters. The drafting team should be applauded for finding a reasonable position.
Response: Thank you for your support.				
Larry E Watt	Lakeland Electric	1	Affirmative	This issue is better handled within the development of the new TPL-001 standard.
Response: The current TPL-002 is in force and will remain so until the completion of the TPL-001-2 effort. This limited scope revision to footnote 'b' is to add clarity to what is in effect.				