Individual or group. (61 Responses)
Name (42 Responses)
Organization (42 Responses)
Group Name (19 Responses)
Lead Contact (19 Responses)
Question 1 (48 Responses)
Question 1 Comments (51 Responses)
Question 2 (43 Responses)
Question 2 Comments (51 Responses)
Question 3 (42 Responses)
Question 3 Comments (51 Responses)
Question 4 (46 Responses)
Question 4 Comments (51 Responses)
Question 5 (0 Responses)
Question 5 Comments (51 Responses)

Group
TVA Transmission Reliability Engineering and Controls
Tim Ponseti, VP
Yes
TVA agrees with the general text; however, TVA believes that the 75 MW limit is too low. TVA believes that a better limit would be 100 MW - which is the amount for load shedding required to be reported under OE-417 under emergency operational policy. This would allow some future load growth as well as any possible new loads that may develop quickly in which a utility may not have time to complete necessary projects in a corrective action plan.
No
TVA recommends that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
TVA would like to propose that this Stakeholder process be postponed in the event that a transmission fix for a load drop issue was already planned within the next 2 or 3 years. Thus the stakeholder process would only occur for projects that had no fix planned within the next couple of years. TVA is also not sure how to satisfactorily address “health, safety, and welfare of the community” - TVA would appreciate some guidance on how to properly address this. TVA believes that item 1.b of Section II could contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
No
TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA believes that only larger load drops (such as 50 MW and above) should require ERO review.
Please see responses to question #2,3, and 4. TVA believes that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Group
Northeast Power Coordinating Council
Guy Zito
No
The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recogn ized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75MW figure. It was included as a result of a Section 1600 Data Request, and is an arbitrary value. There should not be a limit without a technically supportable reliability based reason.
There are no limits on non-consequential load loss for Single Contingency P2-2 and P2-3 (HV only), multiple

Contingencies P4 and P5 (HV only), and P6 and P7. Footnote 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3 (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Individual
Thad Ness
American Electric Power
Yes
Yes
Yes
Yes
Group
Southwest Power Pool Reliability Standards Development Team
Jonathan Hayes
Yes
Yes
Yes
In this section the reference to Customers should only be Customers of Transmission and not open ended for any customer. Once it is sold wholesale the TP wouldn't know where it is being sent to. We would also note that under some jurisdictions that there is a minimum duration threshold for keeping historical data on some of these events that are being requested under this section. Need to add language to accommodate these thresholds so as not to contradict what is being asked for by the regulatory bodies.
No
Section III is superfluous if the regulatory bodies are attending the open stakeholder process. This section should be removed due to the fact that if there is an issue or question on these events they should be addressed in the open stakeholder meeting. Not sure why the team decided to add the ERO as an entity to check after the regulatory body has approved the use. We feel like if there needs to bee coordination between affected entities that they could participate in the open stakeholder process as well. You could add that they include possible affected entities to the invite list of the open meeting to discuss these footnote applications under section 1.
Individual
Kenn Backholm
Public Utility District No.1 of Snohomish County
No
We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies "P1.4 Loss of a Shunt Device" and "P2.1 Opening of a line section w/o a fault" are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies "P2.2 Bus Section fault" and "P2.3 Internal Breaker Fault" were previously defined as category "C multiple contingencies" with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category "C multiple contingencies" with Firm loading shedding allowed. In version

2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using "must-run" generation. 4) As demonstrated by multiple questions at the last webinar, many utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads " 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load." This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words "under footnote 12" added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read "When Non-Consequential Load Loss is used under footnote 12 within the Near-Term …"
No
In the first sentence, remove the words "as an element of a Corrective Action Plan." There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
No
We suggest removing section 2b "Assessment…health, safety…" for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
No
1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."
Public Utility District No.1 of Snohomish County generally disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (Planning Events and Extreme Events). "Footnote b) An objective of the planning process is to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events. Curtailment of firm transfers is allowed when achieved through the appropriate re-dispatch of resources obligated to re-dispatch, where it can be demonstrated that Facilities, internal and external to the Transmission Planner's planning region, remain within applicable Facility Ratings and the re-dispatch does not result in the shedding of any Firm Demand. It is recognized that Firm Demand will be interrupted if it is: (1) directly served by the Elements removed from service as a result of the Contingency, or (2) Interruptible Demand or Demand-Side Management Load. In limited circumstances, Firm Demand may be interrupted throughout the planning horizon to ensure that BES performance requirements are met. However, when interruption of Firm Demand is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the use of Firm Demand interruption meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW." "Footnote 12. An objective of the planning process is to minimize the likelihood

and magnitude of Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed throughout the planning horizon to ensure that BES performance requirements are met. However, when Non-Consequential Load Loss is utilized within the Near-Term Transmission Planning Horizon to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1. In no case can the planned Non-Consequential Load Loss under footnote 12 exceed '75' MW." The proposed revisions require that a Transmission Planner or Planning Coordinator provide assurance that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the interruptions of firm demand under TPL-002 footnote 'b' or TPL-001 footnote '12' if the voltage level of the contingency is greater than 300 kV with certain sub-conditions or if the planned interruption of firm demand under these footnotes is greater than 25 MVA. In addition, under no case can planned Non-Consequential Load Loss exceed 75 MW. The magnitude and duration of load loss is a Level of Service ("LOS") or Customer Service issue that is the jurisdiction of Public Utility Commissions and Local Electric Utility and Municipality boards. The boards and commissions represent their customers which often have diverse service and rate expectations that often are a result of local industry requirements, geography, urban/rural characteristics, and other factors of the particular service territory. Boards and commissions hold public meetings seeking input on various utility matters that often address services and rates. The rate impacts for customers are important; often more important than the service levels depending on the particular customer or customer class. Local boards and commissions are very close to these issues and weigh the input provided through public testimony to best represent their customer needs over the region they represent and have jurisdiction under state and local codes to address. The 75 MW Non-Consequential Load Loss threshold and the required NERC process do not resolve or address a reliability issue. The TPL footnotes address service requirements and should not be part of a NERC Reliability Standard any more than mandating specific System Average Interruption Frequency Index ("SAIFI") and System Average Interruption Duration Index ("SAIDI"). The Non-Consequential Load Loss requirement is an economic driven threshold that is not consistent throughout North America due to diverse customer needs and expectations. For instance, in some areas it may make economic sense and receive local approval to fund a $100 million system reinforcement to mitigate 1 in 20 year (5 percent chance of occurring) 76 MW Non-Consequential Load Loss exposure. However there are many communities that could not justify or support multi-million facilities to mitigate a 1 in 20 year event that may cause the Non-Consequential Load Loss of 76 MW of load. Public Utility District No.1 of Snohomish County supports removing the Non-Consequential Load Loss thresholds from the TPL Reliability Standards and allow the local boards and commissions to continue to address Customer Service Level issues as they are closest to the customers' needs and have jurisdiction over this issue.
Group
MRO NSRF
WILL SMITH
No
(1) Change the wording at the end of the first sentence from "following Contingency events" to "following Contingency events and Contingency events during the planned (maintenance) outage of any bulk electric equipment)". This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) Raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determininge when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, "This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion). (4) If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? Does it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? Does this load count towards the 25 MW and 75 MW thresholds? RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (5) If multiple companies own portions of the non-consequential load loss a used to mitigate a contingency at a single substation does each company's load portion count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? For example, 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption from under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

Yes
(1) In Attachment 1 Section I, what is the definition of a “stakeholder”? Which NERC functional entities would be included (TO, TOP, LSE)? Are the public residential and/or business owners that are affected included in the definition? Some parties may assume that local government representatives or residential or business owners are included as stakeholders. We believe it is most appropriate for the Transmission Owners, Transmission Operators, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. RECOMMENDATION: Define stakeholder to be “affected Transmission Owners, Transmission Operators, and Load-Serving Entities.” (2) In Attachment 1 Section I item 1, what does “including applicable regulatory authorities” refer to? Is this the same body that “applicable regulatory authority or governing body” refers to in Section III? Are these requirements still applicable if the 25 MW threshold in Section III is not passed? RECOMMENDATION: Attachment 1 Section I Item 1 could read “… including applicable regulatory authorities or governing bodies responsible for retail electric service issues as described in Section III. A less vague statement allows the important parties to be included in every instance Attachment 1 is used.
No
Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC.
No
(1) In Attachment 1 Section III, what is the definition of “applicable regulatory authority or governing body”? Is this the state PSC or PUC? Is it the Regional Reliability Organization (RRO)? Is it the Reliability Coordinator (RC)? RECOMMENDATION: Depending on the answer to the above question, define “applicable regulatory authority or governing body” more precisely. The language could read “applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission”. A less vague statement allows the important parties to be included in every instance Attachment 1 is used. (2) In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be counted individually? EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ exceed 75 MW for any single contingency.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. (3) If non-consequential load loss is planned at multiple bulk delivery points in close proximity to mitigate different contingencies should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be compared individually? For example, there are two load serving substations (X load at substation B and Y load at substation C) on a networked 115 kV line with 230/115 kV transformation at both ends (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C that would trip X amount of load if one end of the 115 kV line tripped and 115 kV voltage was below allowable levels, and would trip Y amount of load if the other end of the 115 kV line tripped and 115 kV voltage was below allowable levels. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? In addition to the aforementioned contingencies, if the 115 kV line between substations B and C opens, both loads X and Y will trip. Now does the X+Y value count towards the 25 MW and 75 MW thresholds? (4) In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote ‘b’ could read “In no case can the planned Firm Demand interruption under footnote ‘b’ (as demonstrated in the near-term horizon analysis) exceed 75 MW.” Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion
1. In TPL-002-1c Table I and TPL-001-2a Table 1 can “Firm Demand interruption” or “Non-Consequential Load Loss” be initiated by a manual event such as operator action or does it need to be automatic? RECOMMENDATION: In TPL-002-1c Table I footnote ‘b’ add a sentence stating “Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe”
Group
Arizona Public Service Company

Janet Smith
No
The 75 MW threshold is too low. No technical justification has been given for choosing 75 MW. It should be a significantly higher value for TPL-002. Currently AZPS does not use non-consequential load dropping to meet any standard but this option should be preserved. There could be times when alternate to the load dropping would be building a new transmission line costing hundreds of millions of dollar for a very low probability scenario of high load conditions. The threshold value should be 100 MW or more.
Yes
No
Item 2b: Reference to health, safety, and welfare is unnecessary. All demand interruption are going to have some impact on health, safety, and welfare. The impact is subjective and will simply result in unnecessary study reports by consultants and will act as a road block.
No
The threshold of 25 MW in item 2 of section III is too low. It should be same as the maximum allowed value in foot note b. In addition, AZPS does not agree that no objection assurance by the Regional Entity should be required. Once the process has been fully vetted by the stakeholders, including the regulatory authority for retail service, there is absolutely no need for Regional Entity involvement. There would be no adverse affect of non-consequential load tripping on the BES. Hence no reason for Regional Entity involvement is needed.
The following comment relates to Table 1. It is not clear why footnote 12 applies only to P2-1. The events P2-2, P2-3, P4, P5 are much less probable and the footnote 12 should be applicable to all these events. Why is that loss of non-consequential load is allowed for line tripping without fault but not for a bus fault which is much less likely and could result into same line trip. Similar arguments apply to other scenarios listed above.
Individual
Travis Metcalfe
Tacoma Power
No
We believe the survey significantly underestimated the use of Non-Consequential Load Shedding because the survey asked about past usage of footnote b under Version 001, not about planned load shedding in TPL version 002 or the proposed footnote 12. TPL version 002 added several new contingencies, and also changed the Non Consequential Load shedding applicability for several contingencies. We have 4 specific concerns, followed by several suggested edits: 1) Analyzing the contingencies “P1.4 Loss of a Shunt Device” and “P2.1 Opening of a line section w/o a fault” are new requirements that will lead to increased use of footnote 12. It is common on fringes of the interconnected system to have weak sources. Significant utility investment will be redirected to remediate these fringe performance issues due to the P2.1 and its associated restrictions for firm load shedding and no RAS or UVLS mitigation. This is a low probability and low impact to the main grid contingency with a high mitigation cost, given the new mitigation restrictions. 2) Contingencies “P2.2 Bus Section fault” and “P2.3 Internal Breaker Fault” were previously defined as category “C multiple contingencies” with the restriction that the Firm Load shedding must be planned/controlled. However Version 002 no longer allows dropping nonconsequential load for EHV but removes all restrictions for HV load shedding. Since these contingencies result in opening the same breakers as category P1 contingencies, the use of footnote 12 should be consistent with P1. 3) Contingencies P3.1-P3.4 were previously defined as category “C multiple contingencies” with Firm loading shedding allowed. In version 2, these contingencies have been changed from allowing planned load shedding to only allowing Non-Consequential load shedding per footnote 12. Although this does not directly impact our utility, the survey results do not include utilities using “must-run” generation. 4) As demonstrated by multiple questions at the last webinar, many utilities do not understand the definition of Non-Consequential Loads, and therefore may not have correctly reported the usage of Non-Consequential Load Shedding. The v2 changes cascade to the unfortunate conclusion that UVLS and RAS are no longer permitted as cost effective transmission performance mitigation, despite new low probability contingencies that drive performance problems at the edges of the network. -Proposed changes: A) Change the maximum amount from 75 MW to 300 MW. Several other standards including CIP have a strong technical basis for selecting 300 MW as the maximum limit for load shedding programs. B) Footnote 12 on contingency 2.1 should be replaced with a new footnote 15 that reads “ 15. For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential Load.” This change would acknowledge that while P2.1 does involve just one element, the likelihood of occurrence is similar to bus section faults, so the resulting system performance requirements should be similar. C) The first two sentences of footnote 12 should be deleted. Remove the first sentence because it is general in nature and is a basic tenant of any load-serving utility. Remove the second sentence because column 7 of Table 1 explicitly states where Non-Consequential Load Loss is allowed. D) The third sentence of footnote 12 should have the words “under footnote 12” added. Without this addition, all Non Consequential Load Loss including the allowed loss for P4, P5 and P6 would still be subject to Appendix 1. The revised sentence would read “When Non-Consequential Load Loss is used under footnote 12 within the Near-Term …”
No

In the first sentence, remove the words "as an element of a Corrective Action Plan." There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Requiring the stakeholder process as part of Corrective Action Plan implies that using footnote 12 cannot be the long term choice. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluated the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities.
No
We suggest removing section 2b "Assessment…health, safety…" for three reasons: 1)All outages have a negative impact on the community. Outages under footnote 12 do not inherently have more significant impact per MWhr lost than other outages allowed per Table 1. By requiring additional analysis for a similar societal impact, this provision discriminates against utilities at the fringes of the system. 2) While reminding planners to consider that their decisions do have real impacts to real people is a laudable goal, including this provision opens the door to significant legal liability and regulatory uncertainty. 3) An appendix to a footnote is the wrong place to introduce such a significant requirement. The Adequate Level of Reliability Task Force would be a more appropriate venue for this idea.
No
1) Similar to our comment on question 2, please remove the words "as an element of a Corrective Action Plan" from the first sentence. There are cases on the fringes of the system where Non-Consequential Load Loss is the preferred alternative in both the long term and short term, not as a temporary patch. Since a Corrective Action Plan is a "list of actions and an associated timetable for implementation to remedy a specific problem," using this term removes the stakeholders ability to evaluate the costs and benefits and instead requires them to treat this a problem where the only solution is building new facilities. 2) For any specific use of footnote b, there could be several applicable regulatory authorities such as small municipalities or public utility districts. The standard should clarify whether the planner must show evidence that every authority did not object, or whether the planner only needs to show that less that 25 MW was not rejected by the regulatory authorities. To accomplish this clarification, we propose: A) In Section III paragraph 1 and paragraph 5 change "regulatory authority or governing body" to "regulatory authorities or governing bodies." B) Add a sentence to bullet 2 to read "If multiple regulatory authorities or governing bodies are responsible for retail electric service issues, only the portion of Non-Consequential Load Loss exceeding 25 MW is subject to section III."
Individual
Steven R. Wallace
Seminole Electric Cooperative, Inc.
Yes
No
#1. It is unclear what factors must be met in order to be an affected stakeholder under the Stakeholder Process in Attachment 1? This process appears to be devoid of any objective factors that can assist an entity in determining whether a party is a stakeholder or not. NERC should define what an "affected stakeholder" is or list factors to assist industry in making such a determination. #2. In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," there was a section added at the end of this subsection that is three lines in length. This section states that a stakeholder process does not need to be repeated unless there has been a "material change." It is clear from the latest webinar presentation on this Project that this language is not "clear and unambiguous". NERC does not present any metrics, whether qualitative or quantitative, to guide industry as to when a material change occurs to an application of footnote 'b.' Without any metrics to guide industry, it is bewildering that NERC reasons that entities will consistently interpret what a material change constitutes. Therefore, SECI believes that this provision is in conflict with the NERC Rules of Procedure and FERC Order 762. #3. In Standard TPL-002-1c, Attachment 1, Section I. "Stakeholder Process," the requirement that the process "shall be documented" was deleted from the first paragraph. It does not appear to be reasonable that a process that is not written, nor known to any stakeholder, meets the common understanding of "open and transparent." Seminole believes that the requirement that the process be documented and that documents be available to potential affected parties be reinstated into the Standard.
Yes
Yes
Individual
Nazra Gladu
Manitoba Hydro

No
Given that it is deemed that a stakeholder procress is required, there is no rationale for a maximum level. The stakeholders are in the best position to judge the appropriate level of allowable curtailment.
No
A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation.
No
The word ‘assure’ should be ‘ensure’ in the opening paragraph of III. Instances for which Regulatory Review of Non-Consequential Load Loss under Footnote 12 is Required.
(1) Effective Date section 5: The language used in the revision that was made is fine, however, where the language has been placed in the section is confusing. The language has been added to the end of the sentence that starts ‘in those jurisdictions where regulatory approval is not required’ and lumped those two concepts together. In our mind, there should be 3 separate concepts 1) where regulatory approval required 2) where regulatory approval not required and 3) as may otherwise be approved by applicable laws. (2) Corresponding changes do not appear to have been made, TPL 1 and TPL 2 are not consistent in terms of the language used in the Effective Date section or the Attachment 1 (the sections to which changes were made since last circulation).
Individual
James Tucker
Deseret Generation & Transmission
No
The limitation of Non-Consequential load loss to the 25 MW-75 MW level with a hard limit at 75 MW is arbitrary and give no deference to the cost of the cure. In the West the high cost of a fix may not be in the public interest. The 75 MW hard high limit should be replaced with a soft 75 MW limit but allowing higher levels if the governing body or regulatory authority approves it.
Yes
Yes
Yes
Individual
Melissa Kurtz
USACE
Individual
Chris Pink
Tri-State Generation & Transmission Association
No
No
NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in “Attachment 1.” How is it appropriate to mandate to functional entities functions that are outside those defined in the NERC functional model?
No
In the NERC Glossary of Terms, Interruptible Demand is defined as “Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment.” The process described in Attachment 1 creates an agreement between stakeholders (aka “end-use customers”) and their transmission providers. Thus, if the process described in Attachment 1 is followed, the “Firm Demand” referenced would be reclassified as “Interruptible Demand.” In essence, “Footnote b” does not allow the interruption of Firm Demand. It merely requires that if interruption of Demand is required, it can only be Interruptible Demand. If this was the intention of FERC, NERC, and the Drafting Team, why didn’t the drafting team just state “Interruption of Firm Demand is not allowed”?
No
How would section III of “Attachment 1” be applied to entities that only deliver wholesale electric service and no retail electric service?
It is not clear how transmission projects with long lead times (such as T-lines) would be handled by “Footnote b”. Is it the drafting team’s intent to make it acceptable for a TP to plan for shedding Firm Demand in the Near Term

Planning Horizon without meeting the conditions shown in “Attachment 1” when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon?
Individual
Andrew Z. Pusztai
American Transmission Company
No
ATC recommends the following alternative language for both Footnote ‘b’ (Table 1 in TPL-002-1c [page 6]) and Footnote ‘12’ (Table 1 in TPL-001-2a [page 14]: (1) Change the wording at the end of the first sentence from “following Contingency events” to “following Contingency events for the prior condition of all equipment in service or during the planned (maintenance) outage of any bulk electric system equipment”. This would remind Transmission Planners and Planning Coordinators to include the consideration of planned outages at demand levels for which the outage would be performed. (2) In the last sentence of the footnote, raise the maximum load dropping threshold for the footnote from 75 MW to 100 MW. A 100 MW threshold is reasonable because the DOE uses the intentional dropping of more than 100 MW as one of the thresholds for determining when enough load is dropped to justify a formal system event analysis. (3) Add a sentence at the end of the footnote to read, “This footnote does not apply to any load that is not NERC registered (e.g. load that does not meet the greater than 25 MW NERC registration criterion).
Yes
No
ATC recommends the following change in Section II of Attachment 1 applicable to both standards TPL-002-1c [page 8] and TLP-001-2a [page16]: Remove Item 2b altogether because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should not be required in the Standards because they are not electric system reliability matters and were not stipulated within the FERC Order762.
Yes
Individual
John Collins
Platte River Power Authority
No
We do not support a maximum threshold. 1) It is not appropriate to enforce a one size fits all maximum value that might unnecessarily over-burden some communities. 2) The public process proposed in this standard provides significant transparency from the transmission utilities and opportunity for community input to decisions that will impact both the community's reliability and rates. 3) Leave the maximum capacity threshold decisions to local regulatory commissions and Boards of Directors.
Yes
Although these descriptive steps for a public process seem out of place in a reliability standard, Section 1 is in line with the planning principles of FERC Order 890.
Yes
No
See answer to Question 1.
Individual
Don Jones
Texas Reliability Entity
Yes
Attachment 1, section I (Stakeholder Process) should be clarified to specify which ‘responsible entity’ needs to utilize or develop a transparent stakeholder process. For example, if a contingency event in Entity A’s system causes Entity B to have to shed non-consequential firm load to meet the BES performance requirements, which Entity is responsible for ensuring the required review? TRE proposes adding the following sentence to the first paragraph to assign responsibility for this type of scenario: “The Planning Coordinator or Transmission Planner accountable for the contingency event will be responsible for implementing the stakeholder process and regulatory review.”
Yes

In Section II, part 1b, TRE suggests replacing 'applicable rating' with 'steady state performance requirments', to account for all the BES performance requirements (in particular, steady-state and post-contingency voltages) for which the footnote may be utilized.
Yes
1. TRE requests clarification whether the 25 MW limit of Non-consequential Load Loss (Section III (2)) applies to a single contingency event for a specific Transmission Planner's region or to the entire Planning Coordinator area. For example, if a single contingency requires multiple Transmisson Planners to shed load, is each Transmission Planner allowed to drop up to 25 MW of load before requiring regulatory review? Or did the SDT intend to require the Transmission Planners/Planning Coordinator to submit the plan for regulatory review if the total load shed for the single contingency equals or exceeds 25 MW? 2. TRE feels that the requirement in Section III that the Planning Coordinator or Transmission Planner must submit information to the ERO for a determination of whether there are "any Adverse Reliability Impacts" is overly burdensome to industry, assuming that this refers to the new definition of "Adverse Reliability Impact" (limited to Instability and Cascading). It is extremely unlikely that any such impacts will result from application of this footnote, and any that might occur will be identified in the stakeholder process. If the ERO determination step is retained, then a timeline should be included for completion of the ERO determination process.
Individual
Kirit Shah
Ameren
No
It appears that a least common denominator approach was used to develop the upper limit of 75 MW. Only 1 out of 18 respondents would drop 75 MW of load, and only two respondents would drop 61-70 MW of load. Our review of the data request responses concludes that only 22% of the respondents that presently utilize footnote "b" would drop more than 50 MW, and only 33% of the respondents that use footnote "b" would drop more than 40 MW. The proposed 75 MW limit is too high and is not supported by the responses to the data request. An upper limit of 40 MW is more appropriate, based on the data responses.
No
It is our opinion that that the stakeholder process should be conducted at least once every five years if non-consequential load is planned to be dropped as part of the Corrective Action Plan to meet single contingency events. If conditions have not materially changed since the last review, this information should still be communicated to the stakeholders.
Yes
We believe that item 1b of Section II would contain critical electric infrastructure information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the material.
No
The responses to the data request indicate that 33% of the respondents that use footnote "b" would drop 20 MW or less for single contingency events. Based on the data, we believe that the threshold for reporting should be 20 MW instead of 25 MW. As noted above in the response to item 1, we also believe that an upper limit of 40 MW should be established, again based on the responses to the data request. We find this proposed stakeholder process unique because we are inviting retail regulatory authorities to become involved in the compliance process for a handful of utilities now, but potentially for more in the future. We are unaware of any other standards where a state governmental agency is needed to grant permission for utilities to utilize certain aspects of the standard. We believe that this proposed process would potentially set a bad precedent, is not good policy for either the regulators or the transmission planners, and does not belong in a NERC standard.
It might be helpful to probe further with the respondents who have no planned upgrades identified to address the dropping of non-consequential load to see what relevant system upgrades might entail, and the estimated costs associated with such upgrades, to address such situations.
Individual
Cheryl Moseley
Electric Reliability Council of Texas, Inc.
No
As an initial matter, ERCOT does not believe the planning process should allow for nonconsequential load shedding under single contingency conditions. Accordingly, ERCOT takes no position on the proposed maximum load shedding amount. Even though the NERC BoT approved the Stakeholder Process, ERCOT does not believe that the Stakeholder Process should be included as an Attachment to a footnote to a reliability standard. Also, there is an inconsistency in the terminology used in the footnotes relative to the load shed – firm demand and non-consequential load are both used. Non-consequential load is the correct term and the language should be consistent. Although it is ERCOT's position that non-consequential load should not be allowed to be shed under single contingency conditions from a planning perspective, if the SDT elects to retain a vehicle for such exceptions,

it should establish objective, reliability based criteria that lend themselves to inclusion in a reliability standard. This is consistent with the general approach for reliability standards, which prescribe the "what", not the "how". If the exceptions are based on objective criteria that are known upfront, and those criteria reflect appropriate reliability based technical justifications, then the risk of unwarranted exceptions to the general prohibition due to misuse of the exception process is mitigated. Furthermore, the exception process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure), which should merely reference authorized exceptions granted pursuant to that process. With respect to the stakeholder process, in no case should a reliability standard mandate a stakeholder process in any respect, procedural or substantive. In ISO/RTO regions, stakeholder processes fall within ISO/RTO governance matters. These issues are beyond the purview of NERC Reliability Standards. In other regions, although the relevant functional entities do not have stakeholder processes analogous to ISOs/RTOs, any relevant processes are similarly beyond the scope of the reliability standards. Accordingly, the SDT should eliminate all revisions related to the establishment of a stakeholder process. As discussed in response to question 5, FERC is not requiring this approach, but rather has only provided guidance with respect to ways to possibly bring the prior proposal in line with applicable regulatory approval standards for reliability standards. Additionally, as a general matter, substantive reliability standards requirements should not be imbedded within a footnote to a requirement. In this case, not only is there a substantive requirement imbedded in the footnote, there is also a substantial attachment (which must become part of the enforceable standard requirements}… and, to make it worse, the attachment is an attachment to the footnote, rather than an attachment to and referred to by a reliability standard requirement.
No
Please see ERCOT's response to Question 1 – stakeholder processes are not appropriate for NERC standards.
No
Please see ERCOT's response to question 1-the NERC Reliability Standards should not contain requirements related to stakeholder processes, whether they are procedural or substantive. If an exception process is retained, it should be outside of the NERC Reliability Standards (e.g. in the Rules of Procedure). To the extent the proposed standard inappropriately retains the stakeholder related aspects, ERCOT also provides the following comments on Section II-the ERCOT comments are in parentheses for easy reference and distinction relative to the proposed requirements. II. Information for Inclusion in Item #3 of the Stakeholder Process The responsible entity shall document the planned use of Firm Demand interruption under footnote 'b' which must include the following: (ERCOT COMMENT: This is all that is needed for this. The documentation would be relative to the objective criteria developed for this purpose.) 1. Conditions under which Firm Demand interruption under footnote 'b' would be necessary: a. System Load level and estimated annual hours of exposure at or above that Load level b. Applicable Contingencies and the Facilities outside their applicable rating due to that Contingency (ERCOT COMMENT: "1" is not necessary if objective criteria are developed as benchmarks for the exception process. In that case, exceptions would only be allowed if the objective criteria were met, regardless of the underlying assumptions related to conditions and contingencies.) 2. Amount of Firm Demand MW to be interrupted with: a. The estimated number and type of customers affected b. Assessment of the effect of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community (ERCOT COMMENT: The considerations reflected in a and b are inappropriate for a reliability standard. Appropriate considerations for reliability standards are related to the reliability performance of the system. The considerations in a and b are more akin to quality of service issues better suited for regional policy discussions. It is not within the purview of the SDT to address those matters.) 3. Estimated frequency of Firm Demand interruption under footnote 'b' based on historical Performance (ERCOT COMMENT: Historical performance is irrelevant. If the SDT is going to retain revisions that accommodate non-consequential load shedding, then the only relevant metrics are the objective criteria that set the benchmarks for such exceptions.) 4. Expected duration of Firm Demand interruption under footnote 'b' based on historical performance (ERCOT COMMENT: See ERCOT response to "3" above.) 5. Future plans to mitigate the need for Firm Demand interruption under footnote 'b' (ERCOT COMMENT: This is redundant to the requirement in the reliability standards that requires a plan to resolve any violations identified in the planning process. Furthermore, if load shedding is allowed, this requirement doesn't make sense. Presumably the idea behind allowing these exceptions is to obviate the prospective need for other alternatives. If that is not the case, then there is no need to allow the exceptions, because the transmission upgrades to mitigate the need for load shedding can be established in the planning horizon.) 6. Verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (ERCOT COMMENT: The basis for the load shedding exception is to provide a means to meet the TPL performance requirements in the context of a planning assessment. Accordingly, this is redundant to the planning assessments, the point of which is to identify and resolve performance issues.) 7. Alternatives to Firm Demand interruption considered and the rationale for not selecting those alternatives under footnote 'b' (ERCOT COMMENT: Load shedding exceptions should be based on objective criteria and be reviewed pursuant to a process external to the NERC reliability standards. Alternative discussions could be part of that external process.) 8. Assessment of potential overlapping uses of footnote 'b' including overlaps with adjacent Transmission Planners and Planning Coordinators (ERCOT COMMENT: It is not clear what this means. Each functional entity performs assessments relative to its own system. This appears to introduce a vague regional transmission planning requirement with no structure or rules for such assessments.)
No
If non-consequential load shedding is allowed for single contingency conditions, as discussed above, it should be

based on objective critieria. As such, there is no need for the proposed stakeholder process, including the Section Ill instances requiring regulatory review. Furthermore, establishing approval roles in planning processes for entities other than the relevant functional entities conflicts with the appropriate roles, and appropriate separation of those roles, of the relevant entities (i.e. the planning authority and the state regulatory body and NERC RE). Typically a functional entity performs the functional activity, and others relevant to the proposed process in the standard perform compliance and regulatory oversight of the functional performance. This is a practical concern, and also potentially raises conflicts between governing authorities that create the separation of roles, where, typically, the relevant authorities establish a functional entity as the planning entity, and NERC and its REs and state regulators (as relevant – e.g. in ERCOT) are charged with compliance and regulatory oversight. As with the other stakeholder process sections, that section should be eliminated.
The SDT is not required to utilize the stakeholder approach by Order 762 or any other relevant FERC orders. FERC merely provided guidance as to how the rejected proposal could be improved. However, if the SDT elects to pursue an exception process, such exceptions should be based on objective criteria, and the process should be external to the NERC Reliability Standards (e.g. in the Rules of Procedure). In Order 693, FERC directed NERC to clarify footnote (b) to prohibit shedding firm load except for consequential load loss (Order 693 at PP 1773, 1794 and 1797}. In a related compliance order, FERC reaffirmed its position. (130 FERC 61,200 (March 18, 2010) at PP 8-10 (Compliance Order)) In a subsequent order, FERC clarified that its Order 693 directive did not preclude consideration of specific comments related to planning the system based on load shedding at the "fringes" of a system. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) FERC held that regional variances for case-specific circumstances or a case-specific exception process to plan for the loss of firm service "at the fringes of various systems" would be acceptable. (131 FERC 61,231 (June 11, 2010) at P 21 (Clarification Order)) However, FERC also stated that it viewed the basis for such exceptions as economic, not reliability, with the justification being that it was not economic to invest in the bulk electric system to serve all non-consequential load customers under some single contingency conditions. (Order 693 at P 1792) FERC made clear that any such regional differences or case specific exception processes cannot reflect the lowest common denominator, and, they must be technically justified, and such justification must be strong. (Clarification Order at P 21, See also Order 693 at P 1794) This is consistent with FERC's position that this is a matter of "fundamental issue of transmission service". (Order 693 at P 1793) In recognizing that meeting firm demand under single contingency conditions is fundamental to transmission service, FERC noted that NERC's definition of firm transmission service is the "highest quality (priority) service offered to customers ... that anticipates no planned interruption." (Order 693 at P 1793) Against this background, NERC filed revisions to footnote b that allowed transmission plans to shed non-consequential load under single contingency conditions, provided appropriate process applied to such planning determinations/outcomes. In Order No. 762, {139 FERC 11 61,060 (April 19, 2012)) FERC rejected the approach proposed by NERC and provided guidance on acceptable approaches to footnote b. However, FERC did not endorse or mandate any particular approach. Rather, it merely urged "NERC to develop in a timely manner an appropriate modification that is responsive to the Commission's directives in Order No. 693 and our concerns set forth in this Final Rule." (Order 762 at P21) FERC stated that in order for any such proposal to have merit, it must be technically justified and must not reflect the lowest common denominator. As discussed, the proposed stakeholder approach is not appropriate for NERC Reliability Standards. The SDT should abandon that approach and consider simple revisions to footnote b that reference a case by case exception process based on objective criteria that is external to the NERC Reliability Standards (e.g. Rules of Procedure). Alternatively, it should develop revisions to the continent-wide standards that clarify that non-consequential load shedding is not generally permitted for single contingency conditions, but, consistent with FERC's orders, exceptions could be established pursuant to regional rules based on the need/appropriateness in a particular region. Consistent with the above discussion, if the SDT elects to pursue revisions that accommodate shedding non-consequential load in transmission planning for single contingency conditions, it should abandon the stakeholder process approach. The establishment of exceptions is better suited for regional rules or pursuant to a process outside of the reliability standards - e.g. via the Rules of Procedure, because such a process is not suited for a continent-wide reliability standard. Regardless of whether the issue is addressed via an external process, or left to regional variances, this issue needs to be addressed in a relatively timely manner because the uncertainty is affecting planning processes.
Individual
David Kiguel
Hydro One Networks Inc.
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed. If it is decided to proceed with the 75 MW or any other value, we propose replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a non-US Registered Entity should be determined by the applicable Regulatory Authority or Governmental Authority or its delegated agency in that is responsible for retail electric service issues in that jurisdiction."

No
The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for non-US entities this section should simply require that the process must be approved by the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service for the load to be curtailed in that jurisdiction.
No
The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for non-US entities this section should simply require that the process information requirements must be in accordance with the requirements of the applicable Regulatory Authority or Governmental Authority or its delegated agency that is responsible for local transmission and retail service in that jurisdiction.
No
The process presented in Section III is overly prescriptive and duplicates information not necessary for its intended purpose. As stated in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language in our response to Q1. If this section is required to address a review of the use of footnote 12 to ensure that there are no wide-spread adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 12, only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as "for those planning events where the use of footnote 12 is referenced." We disagree with the need to submit this information to the ERO for a determination of whether there are any Adverse Reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with (and not required for) all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL-001-2 should be sufficient.
(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the bulk electric system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (particularly those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-2a (previous TPL-001-2 approved by the NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 12 that is allowed for the P1 events. If a load is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load if the primary breaker fails (the event becomes category P4) and the fault is cleared by other breakers. Similarly, if the same breaker has an internal fault or there is a fault on the same bus section (Category P2) or there is a failure of a relay (Category P5), which results in the loss of the same EHV transmission line, it should be allowed to interrupt the same load. Events in P2, P4, and P5 can involve more elements and can be more onerouse and stressful to the system than the P1 events, and if use of footnote 12 is permitted in the less stressful P1 events, it must also be permitted in P2, P4 and P5 events. This issue has been raised by many entities in previous occasions and we believe the STD has not provided a convincing response. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve them. Accordingly, we believe that the focus of foot note 'b', and footnote 12 should be that interruption of load must not have a widespread, adverse impact on the reliability of the interconnected BES. A continent-wide reliability standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. If NERC and/or FERC believe that MW threshold needs to be addressed within NERC Standard for US registered entities then the standard must clearly state that the requirement is for US registered entities only.
Group
Seattle City Light
paul haase
Individual
Martyn Turner
LCRA Transmission Service Corporation
No
No
No

No
LCRA TSC disagrees with the October 2012 revision of TPL Table 1 Steady State & Stability Performance Footnotes (TPL-002-1c, footnote ‘b’ and TPL-001-2a footnote 12). The proposed stakeholder process required to be conducted during each Planning Assessment is overly burdensome. Further, it is not clear from the proposed process that a key concern expressed by the Commission with respect to use of Firm Demand load shedding is addressed - Notice to Firm Demand Customers. In addition, the proposed stakeholder process introduces several questions that need to be further clarified. For example: 1) Who defines the processes and procedures to be used? 2) Who is/are the decision maker(s)? 3) Who determines if the processes and procedures were followed? 4) Who carries out the administrative tasks (such as notice, securing meeting space,….)? 5) Who can participate? Does someone need to demonstrate a material interest in order to participate? 6) What are the means of participation (accepted forms of communication, timelines…)? 7) What are the criteria for decision-making? 8) What is the process for dispute resolution? How would does an Attachment become part of a NERC Standard? Should Attachment 1 be a requirement? In addition, support is needed for the bright-line 25 MW level. Lastly, the statement, “Before a Firm Demand interruption under footnote ‘b’ is allowed to be utilized as an element of a Corrective Action Plan in Year One of the Planning Assessment,” implies that Firm Demand interruption may be used for years two through five of the Planning Assessment without the stakeholder process.
Group
Duke Energy
Greg Rowland
No
Regarding the maximum capacity item, we believe that 75 MW is much too low. While Duke Energy has not historically used the footnote, setting the upper limit at 75 MW raises a concern. An upper limit of 75 MW severely limits the ability of a Transmission Planner to use the footnote. The 75 MW limit appears to be the maximum reported in the survey. The survey is a snapshot in time and to assume that there never have been nor never will be situations where the correct decision of a Transmission Planner and its stakeholders would be to exceed the 75 MW limit is illogical. The 75 MW limit is likely to create a situation where a Transmission Planner is forced to convert a network line to radial in order to remain in compliance with the standard, to the detriment of reliability to customers. The key to understanding use of the footnote is realizing that, in most cases, using the footnote is extremely unlikely to result in customer outages, because the probablility of the initiating contingency occurring under conditions requiring additional load shed is very low. A more reasonable upper limit would be the 300 MW limit that is established as the threshold for DOE Disturbance Reporting. It is also important to remember that no matter what upper limit is established, Non-consequential Load Loss of 25 MW or greater cannot be included in Year One of the Planning Assessment if the applicable regulatory authority or governing body responsible for retail electric service issues objects.
Yes
Yes
Yes
Individual
Joe Tarantino
Sacramento Municipal Utility District
No
There is no reliability benefit with an establish MW threshold. Implementing any threshold is descriptive and the standard should depict an outcome not the means of the outcome.
1) The decision of necessary infrastructure addition versus a determination of load shed in lieu of costly transmission should be determined at the Public Utility Commission or Local Board of Directors not through a laod level limitation. 2) There are no impacts to the BES for load shedding actions where it is determined that it is confined to a set boundaryand demonstrate to not lead to cascading, uncrontrolled separation or blackout. 3) Where a concern that a stakeholder process be "gamed" to allow the unscrupulous entity to claim notification of affected stakeholders was followed should not dictate a continent-wide standard direction for other stakeholders.
Individual

Patricia Robertson
BC Hydro and Power Authority
BC Hydro appreciates the efforts of the SDT in revising standards TPL-002-1c – System Performance Following Loss of a Single BES Element (footnote b) and TPL-001-2a – Transmission System Planning Performance Requirements (footnote 12). BC Hydro votes YES in support of this ballot and wishes to provide the following two comments: 1.At this time BC Hydro has concerns about the level of stakeholder consultation that might be required as a result of the implementation of this standard and will bring this concern to the attention of our regulator if necessary. 2.At this time BC Hydro has concerns about the instances for which regulatory review of non-consequential load loss under footnote 12 is required and will discuss those with our regulator if necessary.
Group
Bonneville Power Administration
Chris Higgins
Yes
Yes
No
BPA does not support including information under Section II.2.b, an assessment of the use of Non-Consequential Load Loss on the health, safety, and welfare of the community. It would be nearly impossible for a planner to predict this in a future case since it is hard to predict what loads will actually materialize in the future. In addition, this information does not support reliability of the BES since reliability of the transmission system is assessed by meeting required technical performance for certain contingencies and under certain conditions.
No
For use of Non-Consequential Load Loss in Year One of the Planning Assessment, BPA believes that assurance received from the applicable regulatory authority or governing body responsible for retail electric service issues is adequate and submission to the ERO for a determination of adverse impact is unnecessary. The local utility and regulators are better positioned to determine adverse impacts on an individual system, whereas the ERO would have to develop a process and criteria for assessing adverse impacts.
Individual
Terry Harbour
MidAmerican Energy Company
No
MidAmerican supports NSRF comments with one change. The proposed NSRF addition of “consideration of planned outages at demand levels for which the outage would be performed” to the text of footnote “b” after “following Contingency events” should not be added. If the addition is made, a reasonable time frame clarification is necessary and should be added such as “greater than 6 months”. The proposed change would then read “consideration of planned outages greater than 6 months or longer at demand levels for which the outage would be performed”.
Yes
However, see the NSRF comments
No
See the NSRF comments
No
Item III of Attachment I should be deleted completely. Non ERO regulatory review is not necessary. Applicable regulatory authority or governing bodies responsible for retail electric service issues are stakeholders which may participate in the stakeholder process. Further, there are concerns compliance may not be possible because item III makes non-NERC applicable regulatory authorities or governing bodies responsible for retail electric service issues part of a NERC mandatory compliance without consequence to the said non-NERC governing bodies. Non-NERC entities are not constrained by NERC mandatory laws and penalties and aren't compelled to perform actions to meet NERC compliance. This opens a risk to any NERC regulated entities governed by such regulatory or governing bodies that do not or may not feel compelled to have a process for the NERC regulatory review specified in item III of attachment I.
See the NSRF comments

Individual
Andrew Gallo
City of Austin dba Austin Energy
Individual
Jason Marshall
New England States Committee on Electricity (NESCOE)
No
The New England States Committee on Electricity (NESCOE) appreciates the opportunity to comment on NERC's proposed revisions to Transmission Planning (TPL) Reliability Standards relating to permissible applications of planned load interruption. NESCOE is New England's Regional State Committee and is governed by a board appointed by the six New England Governors. These comments reflect the collective view of the six New England states. The issue of planned, limited load interruption rests at the central intersection of cost and reliability. It illustrates the fundamental balance that Commissioner Norris details in Order No. 762: the tradeoffs between "increasing levels of reliability and the costs that come along with achieving them." Transmission Planning Reliability Standards, Order No. 762, 139 FERC ¶ 61,060 (April 19, 2012) (Norris, Comm'r. concurring in part and dissenting in part) at 2. NESCOE agrees with Commissioner Norris that, as a general matter, this balancing should translate to a more explicit consideration of costs in the NERC standard development process. Id. at 1. The language in footnote "b"—and corresponding footnote 12 of TPL-001-2—implicitly recognizes cost considerations in transmission planning by tolerating limited load shedding under defined circumstances. NESCOE offers below comments and suggestions in response to the SDT's questions. These responses reflect NESCOE's interest in planning for a robust bulk electric system while taking into account the magnitude of risk that a solution is intended to address and the costs associated with competing solutions. NESCOE appreciates the work of the SDT in attempting to respond to the Commission's directives and the time constraints under which the SDT was required to make changes to footnote "b." However, NESCOE is concerned that establishing a bright-line maximum capacity threshold that is an absolute ceiling is overly prescriptive and unnecessary to meet the Commission's directives. In Order 762, the Commission rejected the contention that regional stakeholder processes should unilaterally determine the appropriate criteria to apply in planning to interrupt firm load. Order 762 at P 32. However, provided that technical parameters are in place, the Commission stated that it would be "amenable" to regional stakeholders establishing such criteria if, for example, NERC or the applicable Regional Entity "developed an exception process that provides flexibility in decisions based" on their expert view of regional considerations. Id. The SDT's proposal, however, would impose a one-size-fits-all requirement that forecloses a regional discussion of the quantitative and qualitative considerations that may justify an exception to the proposed 75 MW maximum capacity value. Such a regional discussion in ongoing in New England. In 2010, ISO New England introduced to stakeholders a draft Transmission Planning Load Interruption Guideline. The Guideline noted that load interruption should not be the principal tool to address transmission system reliability violations and highlighted the priority of reliable service. However, applying quantitative and qualitative criteria, the Guideline proposed for stakeholder discussion various levels of controlled load interruption in N-1-1 conditions—potentially up to hundreds of megawatts—that may be tolerated under clearly defined conditions. NESCOE did not take a view of the Guideline when it was presented for review and does not do so here. For now, the Guideline remains in draft form following stakeholder comment in 2011. However, imposition of a maximum capacity threshold that is an absolute ceiling for N-1 events and potentially, through revisions to footnote 12, N-1-1 events, would prematurely limit important regional discussions of this issue. A better approach, and one which the Commission appears amenable, would be to accompany any bright-line value with an exception process. There is recent precedent supporting such an approach: NERC proposed changes to its Rules of Procedure to accommodate exceptions to the proposed 100 kV bright-line Bulk Electric System definition. Separately, the footnote references Attachment 1 to the respective planning standards, which requires a stakeholder process review of the utilization of planned interruption. Such review is only triggered if utilization is sought in the Near-Term Transmission Planning Horizon, even though the footnote permits utilization of load interruption throughout the planning horizon. NESCOE does not support this limiting language, which is at tension with an open and transparent planning process over the entire planning horizon. The term "Near-Term" should be stricken or further justification should be provided.
No
NESCOE appreciates the efforts of the SDT in developing a stakeholder process for considering the use of load interruption in system planning. NESCOE especially appreciates the heightened role accorded to states in light of jurisdictional issues raised by the prospect of shedding load and implications for retail customers. States must be intimately involved in weighing reliability considerations against the economic implications of alternative approaches. Regarding the language in Section I, see the comments above regarding striking "Near-Term" in this context. NESCOE also suggests that additional clarity is needed regarding the intended meaning of "applicable regulatory authorities or governing bodies responsible for retail electric service issues." This language potentially implicates state agencies beyond public utility commissions (e.g., state consumer advocates, attorneys general) and could create confusion for state agencies as well as transmission planners that are required to provide notice to such entities and, pursuant to Section III, provide a process for regulatory review. Instead, the SDT should revise the language to read "electric retail regulatory authorities," a term with clear meaning that the Commission has itself used. See, e.g., Order 719.

Yes
NESCOE agrees with the list provided in Section II. Regarding item #7, in the interest of explicit direction, NESCOE suggests adding at the end of the sentence the following language: "and cost comparisons of all alternatives."
No
NESCOE is concerned that the 25 MW minimum value for regulatory review lacks sufficient technical justification. NESCOE understands that the SDT used responses to data requests to establish this 25 MW value, which is based on the average number of MWs that entities applying footnote "b" reported using in transmission planning. This may be a good starting point, but additional analysis is warranted. Specifically, the analysis should consider a more direct nexus to the system, such as substation design criteria. Additionally, as detailed above, Attachment 1 should provide clarity regarding the meaning of "applicable regulatory authorities." Moreover, clarification is required regarding the initial triggering factor for regulatory review. Section III states that the regulatory review process is required before the footnote can be utilized in "Year One" of the planning horizon. Does this mean that such regulatory review only applies to year one or does it apply to year one and beyond? If the former, NERC needs to provide a clear rationale for restricting such review when limiting factors are already applied (i.e., voltages greater than 300 kV or a 25 MW minimum threshold value).
Group
Tri-State G&T
Chris Pink
1. It is not clear how transmission projects with long lead times (such as T-lines) would be handled by "Footnote b". In other words, it is not clear if it is acceptable for a TP to plan for shedding Firm Demand in the Near Term Planning Horizon without meeting the conditions shown in "Attachment 1" when a mitigating project is planned that cannot be constructed in the Near Term Planning Horizon. 2. NERC Functional Model definitions for Planning Authorities and Transmission Planners do not include the types of activities being proposed in "Attachment 1." As written, this standard mandates functions on functional entities that are outside those defined by the NERC Functional Model. 3. In the NERC Glossary of Terms, Interruptible Demand is defined as "Demand that the end-use customer makes available to its Load-Serving Entity via contract or agreement for curtailment." The process described in Attachment 1 creates an agreement between stakeholders (aka "end-use customers") and their transmission providers for shedding Demand. Thus, if the process described in Attachment 1 is followed, the "Firm Demand" referenced in "Footnote b" would be reclassified as "Interruptible Demand." In essence, Firm Demand would not be interrupted. If this was the intention of FERC, NERC, and the Drafting Team, the standard should just state "Interruption of Firm Demand is not allowed." 4. It is not clear how section III of "Attachment 1" would be applied to entities that only deliver wholesale electric service and not retail electric service.
Individual
Frederick R Plett
Massachusetts Attorney General
No
Although I voted for this Footnote, I do have concerns. 1) There is no reliability benefit to the 75MVA threshold limit. There should be no limit in the standard – it should be between stakeholders to decide that limit, not nationally imposed. 2) Any such agreement to consider non-consequential losses should have no impact to the BES especially when maintained in a confined boundary. 3) This takes away local decision making of PUC/ Local Board decision making; 4) FERC's concern that a few entities would disguise the "stakeholder" process to shed load is unfounded and should not be applied on a continent-wide basis. FERC is trying to impose tighter standards than the industry wants.
Yes
Yes
No
The 75 MW and 25 MW limits do not belong there. It would be best if the limits were established by stakeholder consensus and by state rulemakings.
Individual
Richard Vine
California Independent System Operator

No
While we have voted in favor of supporting the changes to the footnote and to move forward with the adoption of the standard, we remain concerned that there is not a good foundation for concluding that loss of load over 75 MW poses a reliability risk to the system compared to some higher MW threshold. Instead, the 75 MW capacity threshold is simply based on the current maximum planned loss of Non-Consequential Load. While we support minimizing reliance on Non-Consequential Load Loss, there may be scenarios where such reliance is unavoidable in the near-term, and therefore may be needed until capital upgrades can be put in place. At a minimum, the footnote or standard should provide for an exception process, should it be necessary for a planned Non-Consequential Load Loss of greater than 75 MW.
Yes
There is no basis to support only allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for a variety of reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year One) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest to remove the word "Near-Term".
Yes
Yes
Despite a public consultation process that includes the regulator(s), the standard then calls for notification to the regulator(s) and only moving forward once the regulator indicates that it does not oppose the shedding of load ("once assurance has been received that…"). This is still requiring the regulator to do something, and could be problematic if no response is provided by the regulator. How would one address silence on the part of the regulator?
A concern with the new TPL-001-2 standard is what we see as being the elimination of the existing footnote c, the footnote that qualified Category C load shedding as "may be necessary". The wording under the new TPL-001-2 appears that load shedding is the unqualified expectation of the criteria for C contingencies.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
Yes
No
We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
We believe that item 1.b of Section II would contain CEII information and should have limited distribution. The appropriate non-disclosure agreements would need to be developed to prevent widespread publication of the information.
Yes
Individual
Randy MacDonald
NB Power Transmission
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no widespread, adverse effect on the reliability of the interconnected bulk electric system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its delegated agencies responsible for local transmission and retail service over the load to be curtailed.
No
The process in Attachment 1 is overly prescriptive. Attachment 1, if retained, needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process in compliance with the applicable regulatory authority oversight.
No

No
Individual
Laurie Williams
Public Service Company of New Mexico
Yes
No
PNM voted yes to the Standard as a whole but would like the SDT to consider the following concern: Part II.2.b of Attachment 1 that requires an assessment of the effect of the use of Non-Consequential Load Loss under Footnote B on the health, safety, and welfare of the community, and PNM believes that assessments of this nature are entirely subjective and will be difficult to comply with and even more difficult to audit. It is our belief that this criteria should be removed from the Standard prior to its ultimate submittal to NERC.
Yes
Yes
Individual
RoLynda Shumpert
South Carolina Electric and Gas
Individual
Patrick Farrell
Southern California Edison Company
No
SCE believes that the maximum capacity threshold should be increased from 75 MW to 250 MW, as 250 MW is the limit utilized by the California Independent System Operator (CAISO) for a consequential load drop for a single contingency. The CAISO has a rigorous transmission planning process that allows it to plan for and permit load shedding up to 250 MW.
Yes
The Stakeholder Process in Section I of Attachment 1 is similar to the method effectively used by the CAISO to manage and incorporate stakeholder input in its annual transmission planning process.
No
SCE participates in the rigorous CAISO annual transmission planning process that considers the information included in the proposed Section II of Attachment 1. However, the proposed language in Section II.2.b. “Assessment of the effect of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community,” seems overly broad and confusing. The California Public Utility Commission (CPUC) and CAISO presently consider these items before approving transmission plans. It is unclear what type of information would be required in order to meet the seemingly broad request contained in Section II.2.b. SCE believes that the language of Section II.2.b. should be removed from Attachment 1, or alternatively, the language should be revised to specifically exempt critical loads, such as hospitals, fire department facilities, law enforcement facilities, and correctional facilities.
No
As applied to SCE’s service territory, Section III of Attachment 1 appears to require written acknowledgement and approval by the CPUC of each and every Firm Demand interruption authorized by the CAISO’s annual transmission plan. In California, the CPUC is notified of and invited to every CAISO meeting on transmission planning, but the CPUC generally does not provide specific written assurances or agreement on detailed elements of the CAISO transmission plan. SCE believes that a general approval of the overall plan from the regulatory body should be adequate.
Footnote “b”/Footnote 12 as currently written does not provide for an exemption to allow for the use of Firm Demand interruption as a short-term solution to transmission problems. Many entities would benefit from being allowed to use Footnote “b”/Footnote 12 as a temporary solution in response to construction delays until facilities to mitigate an N-1 contingency identified in a Planning Assessment can be installed. Under the current proposal, the stakeholder process will provide very little value in attempting to resolve such a problem. In fact, the current Footnote “b”/Footnote 12 could result in a stakeholder process that may actually slow the implementation of mitigation measures for the system.

Group
MEAG Power
Scott Miller
Individual
Donald Weaver
NBSO
No
We do not agree with setting a MW limit for non-consequential load loss. The allowable amount should be determined and approved by the jurisdiction of the area(s) whose load is affected. The intent of the TPL standard and this footnote is to ensure that if non-sequential load loss is accounted for or relied up to ensure BES reliability (as assessed in the planning horizon), that such a decision needs to be approved by the appropriate jurisdiction. Non-consequential load loss being applied or considered to achieve BES reliability in planning assessment is in itself not a BES reliability concern that rises up to a continent-wide reliability standard.
No
(1) The process presented in Section I of Attachment I is overly prescriptive. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through an open and transparent stakeholder process developed and/or approved by the jurisdiction (a Regional Entity or regulatory authority) of the area(s) whose load is affected area. (2) There is no basis to support allowing the utilization of the footnote in the Near-Term Transmission Planning Horizon of the Planning Assessment only. The footnote itself should not explicitly restrict its utilization to only the Near-Term horizon. Often, in the long-term planning horizon, when approval for transmission addition or reinforcement cannot be obtained for whatever reasons, utilization of the footnote is considered and adopted, subject to stakeholder's and regulatory authority's approvals. Note that it is impractical to add or reinforce transmission facilities in a near-term planning (e.g. Year 0ne) time frame and hence the proposed provision does not allow for utilizing the footnote for the interim period before new or reinforced transmission facilities are put in place. We suggest removing the word "Near-Term".
No
We do not agree with the need for Section II (and Attachment I as a whole) at all. The footnote, or Attachment I, should only stipulate that when Non-Consequential Load Loss is needed to ensure that BES performance requirements are met, then regulatory approval from local jurisdiction needs to be provided with demonstration that the approval was obtained through an open stakeholder process.
No
See our comments under Q2 and Q3, above.
Individual
Milorad Papic
Idaho Power Company
Yes
Yes
Yes
Yes
Group
Southern Company
Antonio Grayson
Yes
No
The complex stakeholder process described in Attachment 1 should be required only if the amount of planned load shed exceeds 25 MW or the contingency is greater than 300 kV. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no good reason to require such a stakeholder process for amounts less than 25 MW. The stakeholder process should only be required for larger amounts of load.
Yes

Yes
Group
Western Area Power Administration
Brandy A. Dunn
No
We do not support a maximum threshold of 75 MW or any MW level. It is not appropriate to enforce a one size fits all maximum value. There are no apparent reliability benefits from implementing a capacity loss limitation...why not pick 300 MW? Also we are not sure what prompted the additional distinction of allowing the load shedding only in the near-term planning horizon...please elaborate.
No
A public process seems out of place in a reliability standard.
Yes
No
See answer to Question 1.
Individual
Jack Stamper
Clark Public Utilities
Individual
Tom Hanzlik
SCE&G
Yes
No
No, We recommend that up to 25 MW of planned interruption be allowed without triggering the need for a stakeholder process. Since the average use given in the survey was 19 MW and there is no evidence of harm to the BES reliability resulting from that use, there is no reason to require a stakeholder process for amounts less than 25 MW. This is consistent with the value cited in Section III.
No
We believe that item 1.b of Section II may contain Critical Energy Infrastructure Information (CEII) and should have limited distribution. The appropriate non-disclosure agreements would be required in order to prevent widespread publication of the information.
Yes
While the current revisions improve the processes described, we have concerns regarding the revisions to TPL002-1 b. 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 specific customers. Service to specific customers and load pockets is jurisdictional to State Commissions. ERO standards should not compromise this jurisdiction. SCE&G believes that any proposed revisions to Footnote B must maintain 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
Individual
Kathleen Goodman
ISO New England
No
The draft footnote states that interruption "is limited to circumstances where the Non-Consequential Load Loss meets the conditions shown in Attachment 1." Attachment 1 appears to impermissibly require State participation in federal transmission planning processes. Further, it places the ERO in a Transmission Planning role, which exceeds the limits of the ERO's functions under Section 215 of the Federal Power Act. The current language

appears to conflict with (1) federal statutes that are clear that wholesale electric transmission issues are matters of federal, and not state, jurisdiction, (2) orders of the Federal Energy Regulatory Commission ("FERC") regarding the role and independence Regional Transmission Organizations ("RTOs") with regard to transmission planning, and (3) Section 215 which limits NERC's authority to regulate "users, owners and operators" of the Bulk-Electric System. Further, the conditions appear to conflict with Section 215 of the Federal Power Act by placing the ERO in a transmission planning role and providing it with regulatory or functional oversight regarding the substance of transmission planning decisions. The ERO has the authority to develop and enforce standards, but is not a transmission planning entity and does not have the authority to substitute its judgment for registered Planning Authorities and Transmission Planners regarding the planning or operation of the bulk power system. Where a review is sought of planning entities' determinations, per FERC-filed Tariffs, they may be brought before FERC under Section 206 of the Federal Power Act. Because the footnote, and the associated Attachment appear to be in conflict with FERC Tariff and other statutory provisions, they should be removed. The footnote itself states, "An objective of the planning process is to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events." The objective statement within the standard does not appear to create a requirement and should be removed.
Yes
No
Section II, 2.a states that studies must address the estimated number and type of customers affected by Non-Consequential Load Shedding. This language should be removed for three reasons. (1) This appears to be inappropriate for a reliability standard. The specific number and type of customers within a set number of MWs that are electrically acceptable do not impact the reliability of the bulk electric system (as defined by Section 215 of the Federal Power Act). (2) Even if the number and type of affected customers were an appropriate process question for an ERO standard, the number and type of customers may change depending on particular system configuration at the time of the load shedding. For example, a substation may be reconfigured to address other system issues such as maintenance and a certain number of MWs of load being interrupted, while still electrically acceptable from a system reliability perspective, may impact different numbers and types of customers. (3) Assuming that the number and type of customers affected were an appropriate metric, the Transmission Planner in many cases will not be the appropriate entity to address these concerns. The Transmission Owner, Distribution Provider or Load Serving Entities would be the appropriate entities to address customer affects. Section II, 2.b should be revised to delete the reference to "health, safety, and welfare of the community." It is inappropriate for a NERC Standard to require planners to address the "health, safety, and welfare of the community." NERC's authority appears limited to regulating the "reliability" of the bulk electric system. Section 215 specifies that NERC's authority it to establish Reliability Standards necessary to ensure an "adequate level of reliability." Reliability Standards may specify the "design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation." Section 215 defines "reliable operation" as "operating the elements of the BPS within equipment and electrical system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of a sudden disturbance, including a cybersecurity incident, or unanticipated failure of system elements." Establishing this requirement is also arbitrary, because it is inconsistent with other transmission planning requirements. For example, the same load could be shed directly as the consequence of a fault and no such assessment is required. In addition, Transmission Planners can plan for the shedding of radial load with no assessment of health, safety and welfare. Section II, requirements 3 and 4 discuss estimating frequency and duration of Non-Consequential Load Loss based on historical performance. This provision is inconsistent with the manner in which transmission system planning is conducted and should be removed. The transmission system planning process uses deterministic not probabilistic assessments. While a power system may utilize these factors in assessing where the use of non-consequential load loss may be acceptable in terms of providing service, these factors do not inform reliability risks to the bulk electric system where the loss of load is found to be electrically acceptable in terms of system reliability (i.e., no thermal, voltage, or stability issues are created or exacerbated and no instability, uncontrolled separation, or cascading failures result).
No
This provision violates both the federal and state jurisdictional split over transmission facilities, and would violate several FERC orders directing the independence of RTOs in the regional system planning process. Said another way, the determinations of a federal transmission planning entity may not be required through an ERO standard to be subject to non-jurisdictional review and approval by state entities. Further, the provision violates Section 215 of the Federal Power Act, as the ERO cannot require the review of a particular transmission system plan by state entities. The following language should therefore be deleted from Section III of Attachment 1: "Before a Non-Consequential Load Loss under footnote 12 is allowed as an element of a Corrective Action Plan in Year One of the Planning Assessment, the Transmission Planner or Planning Coordinator must assure that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 12… ." Overall, the order of Section III is also notable. During year, two through ten of the overall planning horizon the standard allows for Non-Consequential Load Loss without state approval. In the first year of the assessment, approval becomes required for Non-Consequential Load Loss. In year one, even if mandating state participation and decisional authority in a federal planning process was legally

permissible, it is too late to allow for any other alternative as transmission planning, siting and construction of non-load loss alternatives would not be completed in the needed period. If there were non-load loss alternatives available, the use of non-consequential load loss would not be necessary, but it would also not be part of a transmission plan. The Regional Entities with NERC oversight perform periodic audits and require self-certification of the planning process. By virtue of the audit and self-certification process, NERC has the ability to monitor the use of Non-Consequential Load Loss in planning assessments. In addition to being notable for the year one timing, Section III seems incomplete. In the case where there is objection to Non-Consequential Load Shedding, the process appears to end without resolution. The submission to the ERO “for a determination of whether there are any Adverse Reliability Impacts caused by the request to utilize footnote 12 for Non-Consequential Load Loss” conflcts with federal law and orders of the Federal Energy Regulatory Commission. As noted above, the ERO is not a planning entity and does not have authority to displace the reliability planning performed by planning entities. Transmission planning entities are those directed by FERC to make the determinations regarding adverse reliability impacts. If any entity wishes to challenge those determinations, it may do so before FERC under Section 215 of the Federal Power Act. Further, this provision would conflict with orders of the FERC regarding the independence of RTOs to conduct the regional transmission planning process. A reliability standard may not change the scope or meaning of federal statutes nor may it contradict or collaterally attack orders of the Federal Energy Regulatory Commission. For these reasons, this provision should be removed from the attachment to the proposed standard.
In summary, the main footnote is unobjectionable, but this standard as proposed has misplaced jurisdictional authority under Section 215 of the Federal Power Act for both states and the ERO through several of the process points and conditions set out in the attachment to the stardard. The removal of references is required for the standard to comport with the law. These revisions to the standard can be made, which would then allow the draft standard to comply with FERC’s further guidance and the other legal limitations described above.
Group
Florida Municipal Power Agency
Frank Gaffney
No
FMPA has two issues: 1. What is the technical justification for 75 MW? There is no other metric in use similar to it. FMPA believes that, if the stakeholder process reveals that the stakeholders are willing to accept decreased service continuity to save money on their electric bills, why should that be limited to 75 MW which has nothing to do with BES reliability. BES reliability will not be impacted until load shedding gets near to the largest single loss of source contingency in relation to supply / demand mismatch. Other standards have chosen the low value of 300 MW as indicative, (e.g., CIP v5 for UFLS, EOP-004 for disturbance reporting); hence, FMPA recommends that the maximum amount of load shedding be 300 MW. 2. The footnote should also address a process whereby the transmission customer agrees to conditional firm service if the Transmission Planner / Transmission Service Provider (TSP) plans on curtailing firm service to that customer following a single contingency. The TSP should not be able to unilaterally degrade service from a state where it was not conditional to a state where it is conditional.
Yes
Yes
No
See FMPA Comments regarding the 75 MW threshold of Question 1.
Individual
Larry Watt
Lakeland Electric
Individual
Chantal Mazza
Hydro Québec TransÉnergie
No
Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed, and the TPL standard should not put a limit at 75 MW.
Even if the SDT said it is not in its scope, the following difficulty with the application of note 12 needs to be addressed by NERC. There are no limit on non-consequential load loss for Single Contingency P2-2, and P2-3. (HV

only), multiple Contingencies P4 and P5 (HV only), and P6 and P7. The note 12 allows limited non-consequential load loss for single contingency P1, Multiple Contingency P3. Non-consequential load loss is not allowed for P2-2 and P2-3. (EHV), and P4 and P5 (EHV). Considering the EHV Facilities, it is not reasonable to accept some non-consequential load loss for single contingency P1 and P2-3, and then deny it for Multiple Contingency categories P4 and P5 which are statistically less frequent than the former. Also, the Multiple Contingency P7 (for which there is no limit on non-consequential load loss) is more frequent than P2-3, P4 and P5. This technical irregularity must be reviewed and addressed.
Individual
Kayleigh Wilkerson
Lincoln Electric System
Yes
Yes
While supportive of Section III, LES believes the language in the last paragraph could be further enhanced with the following changes [located in brackets] to ensure a complete and accurate record is provided to the ERO. "Once [written] assurance has been received that the applicable regulatory authority or governing body responsible for retail electric service issues does not object to the use of Non-Consequential Load Loss under footnote 'b', the Planning Coordinator or Transmission Planner must submit the [written assurance and] information outlined in items II.1 through II.8 above to the ERO…".
Group
National Association of Regulatory Utility Commissioners
Holly Rachel Smith, Assistant General Counsel
No
As NARUC stated plainly in its Comments filed in FERC Docket No. RM11-18 (Dec. 20, 2011), "not only does the law require that the States maintain authority over distribution level reliability, States are in the best position to guide load shedding so that it has the least negative impact on the State's customers and the operation of the local distribution system." Id at p. 4. Given the twin responsibilities of FERC to maintain bulk system reliability and the states to ensure reliable and affordable service to retail load, NARUC supports the portion of the standard that requires notification and consultation with state and local regulators. However, the maximum capacity threshold (set at 75 MW) is problematic. In this instance, it appears that the 75 MW maximum capacity threshold is merely a reflection of antidotal information from five data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the state/local regulator is consulted in this process, the maximum capacity threshold should just be dropped. States should be able to authorize an 80 MW exception, or whatever level is reasonable, under specific circumstances if local economics and reliability warrant it.
No
It appears that the 25 MW minimum value is merely a reflection of antidotal information from a small number of data request responders and as such is not technically justified. NARUC is not poised to offer an alternative; given that the State/local regulator is consulted in this process, States should be appraised if any load is anticipated to be shed under any planning criteria. Thus, no mimimum value should be set.
Group
Associated Electric Cooperative, Inc. - JRO00088
David Dockery - NERC Realiability Compliance Coordinator
Individual
Mark Westendorf
Midwest Independent Transmission System Operator, Inc.
No
No. We believe footnote b in NERC TPL 002-1 and/or footnote 12 in TPL-001-2 should be eliminated because the intent of these standards is not to rely on non-consequential firm load shedding after a single contingency event. However, if these footnotes are not eliminated, there should be some limitation on how much firm load shed is allowed. We object to any level higher than the proposed 75 MW level and would prefer a level below 75 MW, but won't object to the proposed 75 MW level if the footnotes are not eliminated.
No

No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
No
No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
No
No. MISO objects to a stakeholder process as outlined in Attachment 1. See our comments under Question 5.
We do not support using a stakeholder process to determine if Non-conseqeuntial Load Loss is appropriate following a single contingency event as a means to satisfy the standard. Stakeholder processes will nearly always result in disagreements. The parties that may be responsible for payment of upgrade costs will not necessarily line up with the parties adversely impacted by the alternative load loss. If the stakeholder process includes all stakeholders, there may be many more stakeholders impacted by upgrade costs based on broader benefits and/or cost sharing than stakeholders impacted by the alternative load loss. This will result in the majority decision of a stakeholder body to most often be one that supports load shed (until it is their turn to be the load that is shed). On the other hand, if the stakeholder process is limited to only the stakeholders directly impacted by the proposed load shed, to the extent those stakeholders pay only a small part of the upgrade costs, they will always select a potentially costly upgrade to avoid load shed. The point is, we do not believe that it possible to have a fair and impartial stakeholder process to correctly determine if and when load shed is acceptable to assist in satisfying a single contingency standard. Since the general intents of the existing TPL-002-1 standard and proposed TPL-001-2 standard are not to rely on any shedding of non-consequenital load to meet a single contingency event, in the event that footnote b of TPL 002-1 or footnote 12 of TPL 001-2 is not eliminated, we believe that it should be narrowly focused only on those situations for which the original footnote was developed: interruption of service to radial customers or some local Network customers, connected to or supplied by the Faulted element or by the affected area, where the overall reliability of the interconnected transmission system is not impacted. We propose that footnote b and footnote 12 be modified as follows to ensure it is not misapplied: "An objective of the planning process is to avoid Non-Consequential Load Loss following Contingency events. In limited circumstances, Non-Consequential Load Loss may be needed within the planning horizon to ensure that BES performance requirements are satisfied. However, Non-consequential Load Loss cannot be used to avoid cascading outages or to maintain system stability. Non-consequential Load Loss also cannot be used to avoid a thermal loading or voltage limit violation on an EHV facility. When Non-Consequential Load Loss is utilized within the planning horizon to address BES performance requirements, such interruption cannot exceed 75 MW and is limited to the following circumstances: • Non-consequential Load Loss is allowed for load served by a radial transmission line to avoid voltage limit violations on the radial transmission line following a single contingency event anywhere on the system.. • Non-consequential load shed is allowed for load within a local area served by not more than two transmission lines and/or transformers to avoid a thermal loading issue or voltage issue in the local area, including the transmission lines and/or transformers supplying the area, for a loss of one of the transmission lines or transformers supplying the area, so long as there are no thermal loading or voltage violations outside the local area." We believe the language above maintains acceptable reliability on the bulk electric system by limiting load shed and violations that require load shed to radial areas or areas that would be served radially following the single contingency. We therefore highly recommend that Attachment I be eliminated entirely and that the footnotes either be eliminated or replaced with the modified version above.
Individual
Dan Inman
Minnkota Power Cooperative
No
1. MPC QUESTION: If a portion of the non-consequential load loss used to mitigate a contingency is controllable by a demand side load management system, can it be excluded from the "Firm Demand interruption" in TPL-002-1c Table I footnote 'b' and/or "Non-Consequential Load Loss" in TPL-001-2a Table 1 footnote 12? a. Would this load count towards the 25 MW and 75 MW thresholds? b. Would it have to be curtailed on a pre-contingent basis in order to be excluded from the non-consequential load total, or can it be excluded even if the curtailment happens through action of the UVLS? c. RECOMMENDATION: When describing "interruption of firm demand" or "non-consequential load loss" in footnote 'b' add the language "not counting load shed on a pre-contingent basis". This would be added to the last sentence of footnote 'b' if it indeed should not be counted towards the 75 MW threshold. Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion. 2. MPC QUESTION: If multiple companies own portions of the non-consequential load loss used to mitigate a contingency at a single substation, does each company's load count towards the 25 MW and 75 MW thresholds or does the total load at the substation count? a. EXAMPLE: 100% of the load at a substation is set to trip with automatic UVLS. Company A, B, and C own load amounts X, Y, and Z at the substation. i. Is the amount of load counted towards the 25 MW and 75 MW thresholds X+Y+Z, or is each counted separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW from one entity." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.

No
1. MPC QUESTION: In Attachment 1 Section I, what is the definition of a "stakeholder"? a. Is this intended to apply to multiple NERC functional entities (DP, TO, TOP, LSE), public residential customers, and/or business owners that are affected by system contingencies? b. RECOMMENDATION: Define stakeholder to be "affected Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities." We believe it is most appropriate for the Transmission Owners, Transmission Operators, Distribution Providers, and Load-Serving Entities to objectively evaluate the risks of load shedding in a local area against the cost impact of a large transmission project on the rate base. 2. MPC QUESTION: In Attachment 1 Section I item 1, what does "including applicable regulatory authorities" refer to? a. Is this the same body that "applicable regulatory authority or governing body" refers to in Section III? b. Are these requirements still applicable if the 25 MW threshold in Section III is not passed? c. RECOMMENDATION: Attachment 1 Section I Item 1 could read "… including applicable regulatory authorities or governing bodies responsible for retail electric service as described in Section III. A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used.
No
1. MPC QUESTION/COMMENT: In Attachment 1 Section II item 2b, "Assessment of the effect … on the health, safety, and welfare of the community" is vague. Clarification is requested. a. RECOMMENDATION: Remove Item 2b because it requires the assessment of the footnote application impact on the potential health, safety, and welfare of the community. These types of assessments should be eliminated because they are not electric system reliability matters and were not stipulated by FERC. In the event that the Standards Development teams choses to keep item 2b, then add language semi-defining this as follows in Attachment 1 Section II Item 2b "...health, safety, and welfare of the community as determined by impact on critical health and emergency services." This allows the Transmission Planner and Planning Coordinator to identify the appropriate parties affected by the contingency to be analyzed in every instance Attachment 1 is used.
No
1. MPC QUESTION: In Attachment 1 Section III, what is the definition of "applicable regulatory authority or governing body"? a. Is this the state Public Service Commission or Public Utilities Commission, the Regional Reliability Organization (RRO), and/or the Reliability Coordinator (RC)? b. RECOMMENDATION: Depending on the answer to the above question, define "applicable regulatory authority or governing body" more precisely. The language could read "applicable regulatory authority or governing body responsible for retail electric service such as the state Public Services Commission or Public Utilities Commission". A clearly defined statement allows the Transmission Planner and Planning Coordinator to identify the appropriate parties to be included in every instance Attachment 1 is used. 2. MPC QUESTION: In Attachment 1, if non-consequential load loss is planned at multiple bulk delivery points to mitigate the same contingency should the total load loss count towards the 25 MW and 75 MW thresholds or should the loads be counted individually? a. EXAMPLE: There are two load serving substations (X load at substation B and Y load at substation C) on a long 115 kV line with 230/115 kV transformation at each end (substation A and substation D). Automatic under-voltage load shedding is in place at substations B and C, the UVLS relays at each substation making load trip decisions based on local voltage (i.e. independent operation). If one end of the 115 kV line trips and 115 kV voltage is below allowable levels at both substations X and Y, then the total load tripped by UVLS will be X+Y. i. Does the X+Y value count towards the 25 MW and 75 MW thresholds or are X and Y counted separately? ii. What if X load is dropped for one contingency and Y load is dropped for a different contingency, is the total load counted X+Y or each load separately? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' exceed 75 MW for any single contingency." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This clarification would explain much more clearly what is counted towards the two thresholds and decrease confusion. 3. MPC QUESTION: In Attachment 1, if UVLS relaying is programmed at a sub to trip the load in stages at multiple voltage setpoints, such that only a fraction of the load is tripped for a given contingency, is the entirety of the load still counted towards the 25 MW and 75 MW thresholds? a. EXAMPLE: Substation B has X load that will trip if the BES voltage gets to 0.92 p.u. and Y that will trip if the BES voltage gets to 0.88 p.u. i. If only X amount of load is required to mitigate a single contingency in the near-term TPL assessment, is X load counted towards the 25 MW and 75 MW thresholds or is X+Y load counted? ii. Is there a difference if the Y load is at a different, nearby substation with both loads having the aforementioned tripping logic? b. RECOMMENDATION: In TPL-002-1c, the last sentence in Table I footnote 'b' could read "In no case can the planned Firm Demand interruption under footnote 'b' (as demonstrated in the near-term horizon analysis) exceed 75 MW at a single substation." Similar language could be added in Attachment 1 Section III in regards to the 25 MW and 75 MW thresholds and in TPL-001-2a as well. This would explain much more clearly what is counted towards the two thresholds and decrease confusion.
1. MPC QUESTION: In TPL-002-1c Table I and TPL-001-2a Table 1 can "Firm Demand interruption" or "Non-Consequential Load Loss" be initiated by a manual event, such as operator action, or does it need to be automatic, such as Under Voltage Load Shedding? a. RECOMMENDATION: In TPL-002-1c Table I footnote 'b', add a sentence stating "Acceptable methods to enact Firm Demand Interruption may include manual or automatic processes that can be initiated within a reasonable timeframe"
Individual

Bob Casey
Georgia Transmission Corp
Yes
Yes
Yes
Yes
Individual
Michael Falvo
Independent Electricity System Operator
No
We disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard. Provided there is no adverse effect on the reliability of the interconnected bulk power system, the effect on customers of a firm demand interruption is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. We propose replacing the sentence, in the footnote and in attachment one, section III that reads: "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW." with "In no case can the planned Non-Consequential Load Loss under footnote 12 exceed 75 MW for US registered entities. The amount of planned Non-Consequential Load Loss under footnote 12 for a Registered Entity that is a Canadian Entity (or a Mexican Entity) should be implemented in a manner that is consistent with/or under the direction of the Applicable Governmental Authority or its agency in Canada (or Mexico).
No
No. The process presented in Section I is overly prescriptive. If a section that prescribes the principles of a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed. Corrective action plans can rarely be implemented in a one-year time frame, and in some cases, limited use of Non-consequential Load Loss will be preferable to unaffordable transmission enhancements, therefore we believe that the use of footnote 'b'/'12' should not be limited to the Near-Term Transmission Planning Horizon. We propose that the phrase "the Near-Term Transmission Planning Horizon of" be deleted from the opening paragraph.
No
No. The process presented in Section II is overly prescriptive. If a section that prescribes the information requirements for a stakeholder process is required, then for Canadian entities this section should simply state that any threshold should be established in a manner consistent with other service levels that apply to local transmission and retail service for the load to be curtailed.
No
No. The process presented in Section III is overly prescriptive and requires information not necessary to the intended purpose. As state in Q1, we disagree with prescribing a fixed MW threshold for Non-Consequential Load Loss in a continent-wide standard, and propose alternate language as stated in Q1 comments. If this section must deal with a review of the use of footnote 'b'/'12' to ensure that there are no adverse reliability impacts on the bulk power system, then it should be limited to the information required for that purpose. Provided there is local support for the use of Non-Consequential Load Loss under footnote 'b'/'12', only information items 6 and 8 from section II are relevant for this assessment—the remainder are not required for this section and should be deleted. As stated in Q2 above, the use of footnote 'b'/'12' shouldn not be limited to the Near-Term Planning Horizon. We propose that the words "in Year One of the Planning Assesssment"be deleted. Items 1 and 2 complicate this section and are unneccesary. They should be replaced by a phrase such as "for those planning events where the use of footnote 'b'/'12' is referenced". We disagree with the need to submit to the ERO for a determination of whether there are any adverse reliability impacts caused by the use of Non-Consequential Load Loss. This will introduce a new type of review at the ERO that will create uneccesary delays and burden, and is inconsistent with and not required for all of the other performance requirements in the TPL standards. Submitting the analysis to the adjacent Planning Coordinators and Tranmission Planners, and any functional entity that requests it, as called for in requirement R8 of TPL001-2 should be sufficient.
(1) We'd like to reiterate our support for allowing load interruption for a single contingency with sufficient review/oversight and under acceptable conditions, including no adverse impact on the reliability of the interconnected bulk power system. The reliability aspects (BES performance requirements) should be reviewed for acceptability by the adjacent Planning Coordinators and Transmission Planners. However, issues pertaining to

economics or externalities which may not be directly reliability-related are always available for review and debate by the stakeholders via the regulatory processes and subject to approval by the regulatory authority of each jurisdiction (including those in Canada and Mexico). (2) Furthermore, we request that Table 1 of TPL-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in P2, P4 and P5 categories to allow the application of footnote 'b'/'12' that is allowed for the P1 events. Events in P2, P4, and P5 can involve more elements and can be more onerous and stressful to the system than the P1 events, and if use of footnote 'b'/'12' is permitted in the less stressful P1 events, it should also be permitted in P2, P4 and P5 events. (3) We suggest that NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. Accordingly, we believe that the focus of footnote 'b', and footnote 12 should be that interruption of load must not have an adverse impact on the reliability of the interconnected bulk power system. A continent-wide standard should not concern itself with the reliability of supply or supply continuity for local load, as that is the responsibility of the applicable regulatory authority or its agencies responsible for local transmission and retail service over the load to be curtailed. As mentioned above, NERC Standards and their requirements should focus on what is the anticipated outcome rather than how to achieve it. In this regard, we believe that Attachment 1 is not necessary because it prescribes a process which goes beyond the outcome of the standard and dictates how stakeholdering must be carried out. The individual jurisdiction should establish the process for ensuring compliance with the standard and decide to what extent a stakeholdering process is necessary to establish the acceptable level of load rejection for the area in a manner consistent with local transmission established service levels.
Group
National Grid
Michael Jones
No
The 75MW of Firm Demand interruption is retail load that is being dropped. Dropping load in the general sense should not be endorsed, but it is recognized that there are special situations where it cannot be avoided. If a regulator responsible for retail load is comfortable with greater than 75MW being dropped in a rare situation, there should not be a requirement to build out of the situation. Provided there is no widespread, adverse effect on the reliability of the interconnected BES, the effect of a firm demand interruption on customers is under the purview of the applicable regulatory authority that is responsible for local transmission and retail service over the load to be curtailed. There is no technical basis for the 75 MW figure with respect to reliability impact. Although, the value was developed by the SDT as a result of their review of Section 1600 Data Request, there was no reliability based analysis performed to identify whether the 75 MW is reasonable number. It is possible that a number either larger or lower could be identified if a reliability and cost-effective analysis is conducted.
No
The current document includes the language: 2. The planned Non-Consequential Load Loss under footnote 12 is greater than or equal to 25 MW. This gives no concept of how long customers could expect to be out of service and hence whether this would be an appropriate approach. Suggest using a value that is based on energy, i.e., MWh. A value of 600MWh would represent 25 MW out for 24 hours, or could be 60 MW out for 10 hours, etc. This would seem to provide a more valuable understanding the true impact to customers in assessing the health, safety and welfare. It is also expected that if Demand Resources are being used that they would be excluded from the term "non-consequencial" load, and that the value being discussed is only that in addition to any Demand Resources being used.
Group
Iberdrola USA
John Allen
No
"Contingency events" should be replaced by "Planning Events." Why would load shedding be limited only for certain circumstances in the Near-Term Transmission Planning Horizon? The Near Term is likely the period when the least can be done to avoid load shedding due to the time required for permitting and construction of facilities. A maximum capacity threshold is reasonable, whether 75 MW or a lower value.
No
"Stakeholders" is undefined – would this be the same stakeholder body identified in the planning process of the Open Access Transmission Tariff?
No
Regarding the documentation required for item 2.b, how are "health, safety, and welfare of the community" to be assessed? What are the metrics? How would compliance with this provision be evaluated?
No
Why would a retail service regulator approve a 300 kV and above performance issue?

A one-paragraph footnote encompassing a 2-page attachment is cumbersome for a Reliability Standard.
Group
ACES Power Marketing Standards Collaborators
Ben Engelby
No
(1) We disagree with placing an upper limit on the amount of firm load shed. Conceptually, it seems like a good idea but we do not believe that such a threshold could ever consider all of the potential issues that could arise and would cause the need to plan to shed firm load. This is especially true considering that the SAR clarifies that the upper threshold will be based on the existing planned load shedding values. Future issues cannot be considered by the information contained in the data request. Consider a situation in which a new transmission line was included in Planning Assessment but cannot be built because right of ways cannot be obtained. Should an upper limit be placed on planned load shed in such a situation? (2) We disagree with the threshold of 75 MW. In Order No. 762, the Commission discussed the "blend concept," where it "envisioned the planner would consider up to 100 MW of planned Firm Demand interruption along with other options to resolve the system performance criteria violation and submit its documentation and explanation to the entity deciding whether the planned load shed is acceptable." (emphasis added) Even the Commission envisioned using higher thresholds. Furthermore, the data appears to show that one instance of Non-Consequential Load Loss would be immediately out of compliance because it is actual 75.2 MW not 75 MW. If the upper threshold is too close to 75 MW, any load growth might also compel the instance to be disqualified. If the SDT plans to keep the upper limit, we suggest increasing the amount to at least 100 MW.
No
(1) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment 1. Because the TPL standards apply to both the PC and TP, one may conclude that both functions need to have a stakeholder process. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We recommend clarifying Attachment 1 that it is acceptable for the TP to rely on the PC's process and that both entities are not required to have redundant processes. The most important point is that stakeholders have an opportunity to participate.
No
(1) Adding the word "effect" on the health, safety, and welfare of the community creates more confusion regarding what is needed for the assessment. We recommend removing the effect clause from Section II. (2) We disagree that the Transmission Planner should be required to provide an assessment at all on the health, safety and welfare of the community. Attachment 1, Section 2a identifies the types of customers that are impacted without needing a formal assessment. Stakeholders will have an opportunity to provide information on impacts of planned load shedding through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Further, these planned interruptions of firm demand are expected to be short in nature so any impact would be de minimis. Finally, an assessment on the health, safety and welfare of the community is an unnecessary burden on the registered entity and is better suited for local governments that can speak through the stakeholder process. (3) Bullet 3 is based on available historical information. While this seems reasonable, we have concerns because of the rare instances that Non-Consequential Load Shed actually occurs. If a TP uses Non-Consequential Load Shed for the first time, there is no historical information. What would be an acceptable basis for the first use of Non-Consequential Load Shed when the entity is without historical information? (4) Expected time duration of the planned load shed is too speculative and should not be required because any duration will likely be a guess. When actual contingencies occur, the time of restoration varies and any time that was selected prior to the event is not likely to be correct. We do not see the value in predicting the duration time because there is too much uncertainty about how long an outage will really last. The SDT needs to clarify what is expected for the duration of the planned load shed. (5) While we appreciate that the response to our comments clarified the intent is that "Possible future plans could include a decision not to mitigate the need for Firm Demand interruption," the language in the Attachment simply does not reflect this. The Attachment specifically states "Future plans to mitigate the need for Non-Consequential Load Loss." A decision not to mitigate the need for Firm Demand interruption is not a future plan to mitigate. Consequently, Attachment 1, section II.5 will need to be modified to implement this intent. Otherwise, this language is certain to be interpreted as requiring a mitigation plan.
No
(1) We disagree with the threshold of 75 MW, as mentioned above.
(1) The SDT needs to consider the connection between the developing standards to maintain and improve reliability with the costs required to meet those standards. We believe there is an imbalance of the costs associated with meeting compliance for the current draft standard with proposed benefit of maintaining reliability of the BPS. This standard is a good candidate for the CEAP initiative to determine the cost benefits of reliability. (2) The standard needs to allow more flexibility regarding the use of planned load shed to address transmission performance issues in the planning horizon. It needs to recognize that these planned load shedding events may only be preliminary decisions for addressing problems that are several years away. If there is little chance that the planned shed load will ever be relied upon in the operating time horizon, there should be much less stringent requirements. For instance, if a PC or TP relies on planned load shed for year five of the planning horizon but year

one does not utilize the planned load shed, they have four years to develop another solution. Why should an entity expend great effort and resources for year five when another solution will likely be developed within that time period? (3) What does “materially changed” mean and what degree of a change would be considered material in the Attachment 1 stakeholder process? The SDT should clarify specific conditions in Section II that would constitute a material change. (4) Thank you for the opportunity to comment.
Individual
Richard Bachmeier
Gainesville Regional Utilities
Individual
Spencer Tacke
Modesto Irrigation District
No
I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2. Thank you.
Yes
Yes
No
I am voting NO because there is no technical basis for use of the 75 and 25 MW absolute threshold values, regardless of the size of the utility's load, referenced in the proposed standard. WECC's past experience with implementation of arbitrary magnitudes for requirements (e.g., the 5% and 7% arbitrary magnitude contingency reserve requirements), has proved to be problematic. I would suggest investigating a technical basis for using a relative requirement, such as percentage of the utility's load, maybe 5% and 2.5%, respectively, and that it be based on technical requirements similar to those found in Table 1 of the WECC Criteria TPL-001-WECC-CRT-2. Thank you.
Individual
Jason Weiers
Otter Tail Power Company
Individual
Alice Ireland
Xcel Energy
No
Although the maximum capacity value is used for planning purposes, how does this correlate with operational standards/issues that may require that value be greater. The planning studies look at very specific seasonal conditions on the system and may not necessarily look at all the states of the transmission system during the normal business day. If an operational event requiring a greater value of Non-Consequential Load Loss (NCLL) is executed and the specific outage was not considered in a planning study, how will this affect compliance with the planning standard. There was no technical rationale by the SDT for selecting the maximum value, thus a limit should not be set and should be left as a general discussion issue in the Stakeholder Process due to the many unforeseen issues that may arise.
Yes
The possibility of NCLL is always present, whether in the planning or operational arena. Section I (#5) should however specifically state that in the dispute resolution process a stakeholder does not have right of refusal for NCLL. This should be especially true when a transmission project has been proposed and NCLL in the interim is required due to the regulatory process, equipment lead time, etc. preventing the completion of project at an earlier time.
No
Section II should be left as part of the resolution in the dispute process and should not be made a requirement. Some in particular include: § II.1. - this should be based only on applicable contingencies or conditions that could require NCLL. Having to include the estimated hours at or above a load level may not always be the most effective way to convey why NCLL will be used and adds little to the argument of why or why not it needs to be used. § II.2.a - This may not always be apparent to the TO serving a wholesale transmission customers (REC, MUNICIPAL,

etc.). This should be eliminated since it does little in emphasizing the need for NCLL. § II.2.b - The "effect" of the use of NCLL may not always be apparent, because it is a perceived condition of what could happen that can be interpreted differently. I agree that it should be mentioned in the Stakeholder process outlining the locations where NCLL will take place and let the dispute process identify and assess the health, safety and welfare of the community. How do you assess the effect in the Planning of NCLL. The effect should be identified by the party being affected and resolved in the dispute process. § II.3 & 4. - This needs to be eliminated. Expected frequency and duration of NCLL based on historical performance DOES NOT GUARANTEE future performance and does little in emphasizing the need for NCLL. II.8 - This should be addressed by the Regional Planning Authority in their regional studies.
No
It does not appear that an entity has any options if the applicable regulatory authority or governing body objects to the use of NCLL in year one. This could potentially occur as a result of load patterns and generation issues submitted by an LSE not necessarily having BES elements and the only solution is to implement NCLL. In year one, it is too late to build any necessary and NCLL may be the only alternative.
Setting limits on the amount of NCLL only sets the stage for failure in the compliance of NERC standards and fails to take note of what is really the issue; the planning of a transmission system that is both reliable and economically viable for all stakeholders and customers. It should be emphasized that the use NCLL in a “planning process” is only assuming the conditions set in the study will exist and in no way reflects the conditions seen during the day to day operation of the transmission system. Xcel Energy is concerned about the previous ability on loss of load in anticipation of the next outage (previously C3 now P6). For TPL-003, loss of load in anticipation of the next system outage was covered under footnote B. Footnote 9 now states, “…the re-dispatch does not result in any Non-Consequential Load Loss. “ This is a large increase in requirements of the transmission system to operate. As written, it appears that footnote 12 is NOT applicable to P6 contingencies. Please clarify is this is the intent.