

**Individual or group. (53 Responses)**  
**Name (41 Responses)**  
**Organization (41 Responses)**  
**Group Name (12 Responses)**  
**Lead Contact (12 Responses)**  
**Contact Organization (12 Responses)**  
**Question 1 (45 Responses)**  
**Question 1 Comments (49 Responses)**  
**Question 2 (45 Responses)**  
**Question 2 Comments (49 Responses)**  
**Question 3 (44 Responses)**  
**Question 3 Comments (49 Responses)**  
**Question 4 (45 Responses)**  
**Question 4 Comments (49 Responses)**  
**Question 5 (0 Responses)**  
**Question 5 Comments (49 Responses)**

Individual
hello
NAT
Group
TVA Transmission Reliability Engineering & Controls
Tim Ponseti, VP
Bulk Transmission Engineering
No
TVA believes that the Stakeholder process is burdensome and should not be required for all levels of footnote b use. TVA beleives that the Stakeholder process should only be used for larger amounts of planned load drop. TVA would like to propose the following: For load loss of less than 50 MW - only TP approval is required; for load loss up to 100 MW - PC approval is required; for load loss up to 300 MW - RRO approval is required. Any load loss over 300 MW would require both RRO & NERC approval. The Stakeholder process would be required for any load loss of 100 MW or more. TVA is basing these levels using OE-417 as a starting point - which must be filed for an uncontrolled load loss of 300 MW as well as load shedding of 100 MW or more implemented under emergency operational policy. TVA believes that the 300 MW is the maximum amount of load that can be dropped without obtaining special permission from both NERC and the RRO.
No
Please see comment for question #1. TVA believes that TPs should be able to drop some load without having to go thru a burdensome process. Only the larger load drop levels should require a Stakeholder review.
No
Under Item #2 - TVA is not sure how to properly address "health, safety, and welfare of the community" from an regulatory standpoint. Please clarify what this would require - such as number of hospitals without emergency backup, etc? Also please see answer to question #1 - TVA beleives that only larger load drops should require a Stakeholder review.
No
Please see answer to question #1. TVA believes that the requirements of 25 MW as well as any Bulk contingency over 300-kV is much too burdensome. TVA beleives that only larger load drops should require a Stakeholder review.
Please see answer to question #1. TVA beleives that only load drops of higher magnitudes go thru the Stakeholder and regulatory review.
Group
Puget Sound Energy
Sunitha Kothapalli

Transmission Planning
Individual
Aaron Staley
Orlando Utilities Commission
Yes
Yes
Yes
Data element 5 should probably read. "List any Future Plans or future system changes to mitigate the need for Firm Demand Interruption under footnote 'b'". There can be cases where there is no planned future project to relive the problem, or it could be expected that load will go down or changes on neighboring systems will relieve the problem.
Yes
Comment #1: The maximum threshold should be in the Footnote, not in the Attachment. Comment #2: I think the role identified for the Regional Entity is appropriate. Comment #3: I like the concept that regulatory approval is not required until year one. However I think either the ordering of language or the formatting needs to be changed to make it clear that the year one applies to only those that need regulatory approval. Maybe change the section to read... "Section III Firm Demand Interruptions under footnote 'b' that meet either or both of the criteria below are required to have approval by the applicable regulatory authority or governing body responsible for retail electric service issues. The regulatory approval is required prior to the use of that remedy in Year One of a Corrective Plan in the Planning Assessment. (Existing 1 & 2) (Existing RE Review)
Individual
Chifong Thomas
BrightSource Energy, Inc.
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.
No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns and different authorities. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for approving retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV inconsistent with P1. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: "Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read: "The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

Individual

Jose H Escamilla
CPS Energy
Yes
Yes
Yes
Yes
Individual
Mark Westendorf
MISO
No
Transmission planning that relies on planned or controlled interruption of non-consequential firm load following loss of a single transmission facility should not be acceptable and removal of footnote 12 should be considered or a modification to allow its use only in conjunction with a petition to FERC to waive (on an exception basis) the requirement to maintain firm load service for a specifically identified system configuration issue warranting Footnote 12's application. If it is determined that a footnote provision is required in the standard, we agree with the description and components of the Stakeholder Process in the body of the footnote, but reserve judgment on the value of the "x" that sets the maximum amount of MW load loss. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.
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 or approved by the Regional Entities (since the RE will eventually need to review and assess the reliability impact of such utilization), with supporting information. (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 leaves the time frame wide open, and does not explicitly or implicitly 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 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". (3) Requirement 8 of the Transmission Planning Standard TPL-001-3 requires notification and response requirements for a Planning Coordinator and/or Transmission Planner for the Planning Assessment to any registered entity having a reliability interest. Attachment I does not recognize this requirement. Attachment I must be coordinated with this administrative requirement.
No
Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the Regional Entities (given the RE will eventually need to review and assess the reliability impact of such utilization). We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RE's review process.
No
We generally agree with the instances for which approval or interruptions is required, but do not agree with the requirement to seek regulatory approval. In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is

unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the RE for review and concurrence. Along with the submission, the RE may require the proponent to include a copy of appropriate regulatory approval (which the entity should have already obtained). The conditions (1) and (2) for seeking regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the RE. Additionally, Attachment 1 requires that the ERO develop a methodology on evaluation criteria to be published for determining Adverse Reliability Impacts for approval by the ERO. Planning Assessments are performed on an annual basis. The Attachment 1 process and ERO methodology may require a lengthy approval process that must be repeated on an annual basis.

(1) The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard. (2) It may be more appropriate to develop a Standards process that covers the technical aspects of using a footnote 12 and leave regulatory review and approval to FERC and State agencies.

Group

Northeast Power Coordinating Council

Guy Zito

Northeast Power Coordinating Council

NPCC reviewed the posted documents, and has no comments for this posting.

Individual

Jennifer Wright

San Diego Gas & Electric

No

We don't support the changes.

No

We don't support the addition of stakeholder process language.

No

We don't support the addition of stakeholder process language.

No

In FERC Order 762, FERC rejected NERC's footnote (b) and urged "...NERC to develop modifications responsive to the Commission's directives in Order No. 693 and our concerns set forth in this final rule." The NERC SDT has done little to address FERC's concerns and instead has resubmitted the same document with additional language. Order 693 directed NERC to develop modifications to TPL-002-0, which clarify footnote (b). As redrafted, footnote (b) does not address FERC's concerns. For example, footnote (b) continues to use the term "Firm Demand," which describes all forms of demand whether served by the faulted element or not. On the contrary, "consequential load loss" is load, which is removed as a result of a fault. Clearly, these are different concepts and the new language does not comply with FERC's directive. FERC's position has been that non-consequential load loss through load shedding shall not be allowed as an exception to TPL-002-0. Also, FERC has stated that the interruption of Firm Transmission not be allowed as an exception. But, Footnote (b) continues to say, "Curtailment of firm transfers is allowed ...". Another inconsistency. Beyond the differences between what FERC directed NERC to do and what NERC did, as written, footnote (b) would introduce "stakeholder interests" into transmission reliability even if those interests do not promote reliability. The TPL standards identify the Planning Authority and Transmission Planner as the entities responsible for meeting the standards and makes no mention stakeholders. To meet the reliability objectives of the standard, the Planning Authority and Transmission Planner are subject to Measures

and the Compliance Monitoring Process. In FERC Order 762, FERC determined "...that openness and transparency do not alone ensure bulk electric system performance criteria will be met..." and was "...not persuaded that developing technical criteria is unachievable." Although FERC does not disagree with adding a stakeholder process, clearly, they do not endorse one and prefer a technical approach to creating the exception under footnote "b".

Individual

Patrick Brown

Essential Power, LLC

No

Although we agree with the majority of the content of the footnote, we're not sure that using a specific amount of load as the bright-line threshold is appropriate. For example, if we make the limit 25 MW, this will have a different impact on different entities, in different regions. For a small TP that may only have a total of 200 MW of load, 25 MW is a significant amount of their overall obligation. For an area with 40,000 MW of load, 25 MW is hardly significant. Additionally, the nature of the load must be taken into consideration as well. Some types of load are more acceptable to lose than others; again, this may vary from region to region. Although we don't have a specific recommendation or solution regarding these issues, I would urge the SDT to take these into consideration in their next revision. The sentence that starts with "When interruption of Firm Demand is utilized..." is confusing as it seems this sentence should only refer to the limited circumstances mentioned within footnote b

Yes

Yes

No

This solution requires filing with a regulatory body for any extra interruptions. This seems to be a lot of effort and language for a contingency event that the system is supposed to be able to handle.

As written, this change is complex and will be difficult to execute without additional turmoil on the planning end and offers limited clarification. Some additional issues to consider; 1. Should this level of contingency allow isolation/removal of load or generation if not part of the outage? 2. Should additional generation be allowed to be removed, again considering the contingency level?

Group

Southwest Power Pool Reliability Standards Development Team

Jonathan Hayes

Southwest Power Pool

Yes

As a concept we agree with the stakeholder process. We would like clarification on why only the Near Term was used for non-consequential load loss and not both Near and Long term. It seems that depending on the time frame we would be held to different requirements of the standard.

Yes

See comment From question 1

No

We need clarification on the term planner in item 8 of section 2. Since the term isn't capitalized we would like to know if this was intended to mean Transmission Planner or a adjacent Planning Coordinator for identifying a seams issue. We would like see item 2b of section 2 removed this item isn't relevant to the standard and goes beyond the purpose of this standard. We understand that this is included for curtailment of load during emergency conditions (EOP001 Attach 1) but feel it is unnecessary in planning.

No

Need clarification around why the 25MWs threshold on generation was thrown into load interruption topic. Looking at the registry criteria for generation the threshold should be 20Mws for a single unit and 75 MWs for aggregated units. Not sure where the 25MWs threshold came from for generation. The 25 MW threshold in Section III is duplicative of the registration limit for generation in the ERO Statement of Compliance Registry Criteria. It is submitted for comment at this time but will not be

finalized until after the above mentioned data request is complete and the final value will be submitted for industry comment and approval in the next posting. The GOP registration criteria is 20MWs. Whereas the registration criteria for LSEs and DPs is 25MWs. There appears to be some mingling of criteria. Additionally this raises the question of whether x =25MWs. Please clarify which you intended to use. We are concerned that getting retail service regulatory authority approval in a quick manner could be difficult. We are also concerned that if it does get caught in the process of being approved and there is no time to construct, that we would not want to be found out of compliance due to something that is out of our control.

We agree the distinction between consequential and non- consequential is necessary. We don't agree that you should plan for non-consequential load loss/shed. You shouldn't have to interrupt firm service for n-1 contingency.

Individual

Keith Morisette

Tacoma Power

No

The layout of Table 1 with "No 12" does not actually indicate that load loss is allowed for those specific contingencies. Also the wording of the footnote appears to require all Non-Consequential Load Loss to go through the attachment 1 process, not just P1.1 to P1.5, P2.1 and P3.1 to P3.5. Instead P1.1 to P1.5 and P3.1 to P3.5 should say "Yes per Attachment 1" and Footnote 12 should be eliminated entirely. Since P2.1 is a new requirement with Version TPL-001-03, the recent NERC survey did not capture utilities currently using Non-Consequential Load Loss to address opening a line without a fault. Furthermore, some utilities may not identify problem lines until their first assessment using TPL-001-3. P2.1 should have a new footnote reading "For this contingency, load which is served radial from a remaining single source line may be shed as if it were Consequential load." Technical Background: Parallel transmission lines serving remote load commonly will not perform with a P2-1 contingency, particularly when the strong source is opened. These issues are particularly common with load in rural settings and the cost to meet urban reliability expectations will be disproportionately expensive. Utilities will be encouraged to configure their system radially, which will be less reliable to meet this rare contingency. FERC has not specifically addressed load shedding associated with open ended lines. In order 693 the Commission was responding to the contingencies in TPL-001-1 that included footnote b. In order 762 and the NOPR RM12-1-000, FERC continues to reference applicability of footnote b to the TPL-001 defined single contingencies, but was otherwise prepared to accept Firm Load Loss for the single contingencies in TPL-001-2 P2.2 to P2.4. In the TPL-001-2, the category of "P2-Single Contingency" expanded to include both a new contingency of an open ended line, and various bus and breaker faults that previously were considered as Multiple Contingency. Based on our experience the likelihood of a line opening is significantly less than for line equipment faults. In addition, during human error caused line open events, personnel are on-site to affect quick restoration. This standard should not impose an upper limit because any planned large load shedding will be reviewed and approved by the applicable regulatory authority. Pending the survey outcome, a limit of 3000 MW consistent with the CIP-002-5 Critical Asset level may be useful if the SDT believes an upper limit is needed.

No

Completing the entire stakeholder process on an annual basis, before the TPL study can be finalized, is not feasible due to long and unpredictable timelines for public involvement and regulatory approval. The stakeholder process should only be repeated when the technical basis as outlined in section II have changed, or when there are new stakeholders. There are cases on the fringes of the system where Firm Demand Interruption as the preferred alternative in both the long term and short term, not as a temporary patch in Corrective Action Plan. To address these issues, Section I should read as: Before the use of Firm Demand interruption is allowed as an element in the Transmission Planning Horizon of the Planning Assessment, the Transmission Planner or Planning Coordinator shall ensure that the utilization of this mitigation is reviewed through an open and transparent stakeholder process. The responsible entity shall document the stakeholder process which shall include the following: 1. Meetings must be open to all affected stakeholders including applicable regulatory Authorities or governing bodies responsible for retail electric service issues. 2. Notice must be provided in advance of meetings to all affected stakeholders, including applicable regulatory authorities or governing bodies responsible for retail electric service issues and include an agenda

with: a. Date, time, and location for the meeting b. Specific applications of the planned Firm Demand interruption under footnote 12 c. Provisions for a stakeholder comment period 3. Information regarding the intended purpose and scope of the proposed Firm Demand interruption under footnote 12 (as shown in Section II below) must be made available to meeting participants. 4. A procedure for stakeholders to submit written questions or concerns and to receive written responses to the submitted questions and concerns. 5. A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction. During each Planning Assessment, the Transmission Planner or Planning Coordinator shall update the information outlined in Section II. If the annual hours of exposure to or the amount of Firm Demand has increase above the previously disclosed level(s), a new Stakeholder process shall be completed within one Calendar year. Every three years the stakeholder process shall reoccur to allow new stakeholders input to the process.

No

Item II.2.b Since this is a stakeholder process, each stakeholder can make an assessment for themselves about the effect of Firm Demand interruption on the health, safety and welfare of the community. This requirement is too vague to be enforceable. Item II.5 Particularly in the case of P2.1 contingencies, utilities may not have any plans to eliminate load shedding "at the fringes of various systems" as the FERC NOPR noted would be acceptable.

No

As noted in our response to question 2, regulatory approval is often a slow process and is not conducive to repeating annually. Instead of a 25 MW limit, a 300 MW limit that corresponds to the reporting level of firm demand in EOP-004 is more appropriate.

FERC order 762 states that "to plan for the loss of firm service at the fringes of various systems would be an acceptable approach." The newly defined contingency P2.1 requiring analysis of open ended line sections should allow load shedding of the load on the line section as suggested in the FERC order.

Individual

John Burnett

Los Angries Department of Water and Power

No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.

No

We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of

customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.

Individual

Nazra Gladu

Manitoba Hydro

No

The maximum limit 'x' MW should vary with system load level and voltage. For example, an 'x' MW interruption would be a very small fraction of a 5000 MW system load level compared to a 1000 MW load level. Similarly, interruption of 'x' MW could be equal to surge impedance loading of a 230 kV line, where as it would be a fraction of a EHV transmission line loading.

No

A stakeholder process should not be required in jurisdictions where a legislation already authorizes interruptions, as consent of stakeholders cannot override legislation. If Firm Demand interruptions require the approval of regulatory authority as described in Section III (for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV), the stakeholder process described in Section I would become a redundant process. Does Section I exclude Firm Demand interruptions addressed under Section III?

No

1 a. It would be very difficult to estimate the annual hours of exposure at or above a certain load level. 2 b. An assessment on the health, safety, and welfare of the community should not be part of a reliability assessment – this is purely subjective. 3 & 4. In situations where load interruption is a new proposal, historical data will not be available. What does the SDT expect here? 5. Is there a requirement to mitigate? If there is a requirement to mitigate, the required time frame is not identified.

No

The Section III states that regulatory authority approval is required for interruptions over 25 MW or if voltage level of the contingency is greater than 300 kV. However, a regulatory authority cannot approve interruption of Firm Demand unless it already has such jurisdiction that is conferred upon them by legislation. A reliability standard cannot confer that jurisdiction. Further, the regulator is already part of the proposed stakeholder group and will have input into the proposal. The Section III requires the Regional Entity to review the proposed use of Firm Demand interruption under footnote 'b'. What impact does it have on the Regional Entity to necessitate a review, if the stakeholders have already agreed to a process, TPL Reliability Standards performance requirements have been verified as in Section II.6, and potential overlapping uses have been assessed with adjacent planners as in Section II.8. What criteria will the Regional Entity use to make their assessment of Adverse Reliability Impacts and potential cumulative effects given the above TPL performance must be met? This requirement can lead to inconsistent decisions between regions.

Please clarify if an entity must set up a stakeholder process if Firm demand interruption is not used as an element of the Corrective Action Plan. As I understand it, the footnote b in TPL 002 will be replicated in the other relevant TPL standards once it is approved. When it is included in the other TPL standards, will it be customized to each standard, or will it appear exactly the same in each standard? Footnote 12 of TPL-001 as currently drafted seems a bit disjointed or incomplete – i.e. its referring to Non Consequential Load Loss and then it refers you to an Attachment for the calculation of Firm Demand interruption without providing a connection between the two concepts .

Individual

Test

TEST

Individual

Michael Falvo

Independent Electricity System Operator

No

Specific to the language used in footnote b, we agree with the concept of an approval process for determining the acceptable level of Firm Demand interruption applicable in a jurisdiction, and do not agree with prescribing a fixed MW threshold for a continent-wide acceptable Firm Demand interruption. Therefore, we recommend removing the last sentence in footnote b) which reads "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW." and also the same sentence from Attachment 1 section III. We believe there should not be a fixed limit on the amount of Firm Demand interruption, for reasons explained below in answers to Questions 4 and 5. As part of a reliability standard, the footnote should clarify the conditions under which load curtailment will be allowed, including mention of processes necessary to manage special circumstances. We generally agree with the reference to Attachment 1, but have concerns about the components of the Stakeholder Process described in Attachment 1, for reasons described in answers to Questions 2, 3 and 4.

No

(1) The process presented in Section I and the rest of Attachment I is overly prescriptive and lengthy. As part of a reliability standard, the footnote and process must focus on the impact that Firm Demand interruption (or Load Rejection) would have on the reliability of the Bulk Electric System and this aspect is covered in Section III. This Section needs only to stipulate that the proposed utilization of the footnote be reviewed through (a) an open and transparent stakeholder process and (b) approved by a relevant reliability authority such as the ERO, Regional Entity or applicable governmental authority since this authority will eventually need to review, assess and approve the reliability impact on the interconnected BES of such utilization, with supporting information. Reliability issues and their assessment and approvals should be dealt with by the applicable reliability authority. Details of other

aspects of Firm Demand interruption, mainly the Stakeholder review and approval process and issues pertaining to the quality of service, economic and welfare impacts of Firm Demand interruption, assessment of alternatives (including their economic and welfare impacts), etc. should be dealt with by the regulatory authority or government body of each jurisdiction (in particular, in non-US jurisdictions), as is the normal practice for all other Transmission Planning activities. (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 leaves the time frame wide open, and does not explicitly or implicitly 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 stakeholders' and regulatory authorities' 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 removing the word "Near-Term".

No

Again, this Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of the footnote, leaving much of the detail to the application process overseen by the applicable reliability authority to review and assess the reliability impact of such utilization. We suggest the SDT to reduce this Section, or remove this altogether with appropriate insertion into Section I that address a general need for supporting information to be specified by the RA's review process. Also note that use of a "stakeholder process", as per FERC's concerns, must be crisp and clear.

No

We generally agree with the instances for which approvals or interruptions are required. Approval is to be granted by the Reliability Coordinator or applicable reliability authority. (1) In general, when the footnote is proposed to be utilized as an interim measure until transmission facilities can be added or reinforced, regulatory approval must be sought in advance. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provides no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. Section III should therefore stipulate a high-level requirement for the proposing entity to submit the proposal to the Reliability Coordinator for review and concurrence. The conditions (1) and (2) for seeking explicit regulatory approval can be retained, but now become the criteria for seeking review and concurrence by the applicable reliability authority. (2) We suggest deleting Item 1 in the first paragraph (with its a and b bullets) and just indicating that planned Firm Demand interruption requires approval if it is greater than 25 MW (or other threshold). Requirements for approval of the use of Firm Demand interruption should be independent of the voltage level of the contingency. (3) We propose deleting the sentence in the second paragraph "In no case can the planned Firm Demand interruption under footnote 'b' exceed 'x' MW". A fixed limit on the allowable size of Firm Demand interruption can not be technically justified for the whole continent and each case should be assessed to determine if its impact on reliability of the bulk transmission system is acceptable or not. The impact of each case on the affected customers (economic, welfare, etc.) will also be reviewed and approved by the regulatory authority or governmental body of each jurisdiction and a "reliability" standard must not impose limits and restrictions pertaining to these aspects. (4) The third paragraph proposes that the Regional Entity should review each case of Firm Demand interruption and verify that there are no Adverse Reliability Impacts. We propose instead that the transmission planner or planning coordinator study the BES performance requirements and the reliability impacts of Firm Demand interruption, including its correct operation, miss-operation, and the failure to operate. The transmission planner should then submit a report of this assessment to the Reliability Coordinator for review and approval.

(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/approved by the Reliability Coordinator. 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-001-3 (previous TPL-001-2 approved by NERC BOT) be corrected for EHV contingencies in

P2, P4 and P5 categories to allow the same load interruption that is allowed for the related P1 contingency. Table 1 currently does not allow any load to be interrupted for an EHV single contingency if the primary circuit breakers fail to clear the fault (Category P4, "Fault plus stuck breaker"). But if load X is allowed to be interrupted for a single EHV transmission line contingency (Category P1), it should be allowed to interrupt the same load X if the primary breaker fails 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 X. (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 the footnote 'b' should be that interruption of load must not adversely impact the reliability of the interconnected BES because reliability of supply to load and/or supply continuity is mandated by the jurisdictional authority. (4) We submit that the scope of NERC's mandatory standards does not extend to assessing or setting requirements for non-jurisdictional entities, unless such facilities are necessary for the operation of the interconnected BES or have an adverse impact on its reliability. For Canadian entities there are regulatory requirements and processes under the purview of the relevant regulatory authorities that we believe are adequate. Accordingly, customer interests are protected and are not subject to unilateral decisions of the transmission planner. In all cases, steps are taken at the planning, design, and operations stages of system development such that non-consequential Firm Demand interruption would not adversely impact the BES and the affected customer has been given the opportunity to avail themselves of other options under the transmission development rules in the relevant jurisdictions. (5) The requirements of the footnote (including attachment) will amount to a mandate to construct additional transmission which is inconsistent with Section 215 (i) (2) of the US Federal Power Act which specifically does not authorize the ERO "to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services. (6) We suggest that NERC should not include and/or address load reliability or load supply continuity requirements within the BES Reliability Standards. In Canada, these requirements and approvals are with relevant reliability or regulatory authority. If NERC feels obligated to include such requirements for load reliability issues in US, then we propose that non-jurisdictional entities must be exempted from these requirements similar to the provisions in NUC 001. (7) The proposed implementation plan conflicts with Ontario regulatory practice respecting the effective date of the standard. It is suggested that this conflict be removed by appending to the implementation plan wording, after each "applicable regulatory approval" in the Effective Dates Section A5 of both draft standards, to the following effect: ", or as otherwise made effective pursuant to the laws applicable to such ERO governmental authorities."

Group
Salt River Project
Bob Steiger
ERC
No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.

No
We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?
No
We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".
No
While we do agree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to give approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.
The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is admitted for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.
Individual
Kirit Shah
Ameren
No
We believe that the NERC Glossary contains an adequate definition for Firm Demand, which does not include Interruptible Demand or Demand-Side Management Load. We do not believe that Interruptible Demand or Demand-Side Management Load needs to be mentioned in the footnote b) as these types of Demand are not Firm Demand. Interruptible Demand can be cut at any time and may contain Demand-Side Management components, and may be direct controlled by the System Operator.
No
We request that Item 1 be modified to include representatives of stakeholders because it may not be practical to open a meeting to all affected stakeholders. The new sentence of Attachment 1 should read, "Meetings must be open to all affected stakeholders, or their representatives, including applicable regulatory authorities or governing bodies responsible for retail electric service issues."

Also, requirements for a meeting location would seem to eliminate electronic participation via webex. It would seem more practical for a TP or PC to host a specific webex to present and discuss the issues associated with the need to drop Firm Demand. Further, we request that a MW threshold be included before the Section I stakeholder process would begin, and believe that a minimum threshold of 10 MW of Firm Demand to be cut would be a reasonable value to initiate a stakeholder process. Levels below 10 MW would be considered as "noise" in the planning horizon. We believe that an approval should be obtained in the Section I process, which would eliminate the need for Section III. By requiring an approval of the appropriate local governing bodies responsible for retail service issues (including rates), there is no need to agree on a cap to limit the amount of Firm Demand dropped.

No

We request that Items 5 and 7 also include information regarding estimated costs and schedule for implementation. Any permitting issues associated with the alternatives should also be included. Any previous attempts to build facilities but were blocked should also be part of the record.

No

We do not believe that section III is needed, and particularly if an approval is included as part of the section I process. We do not subscribe to dropping Firm Demand (non-consequential load) for single contingency events, and do not see a need to include a voltage threshold as part of the contingency requirements. All single contingencies in Category B should be applicable.

To clarify, the Stakeholder Process should not be initiated until the amount of Firm Demand expected to be interrupted by the TP or PC as mitigation reaches a threshold of 10 MW. However, at that point, the Stakeholder Process should commence, but not without incorporating the need to obtain approvals from the stakeholders, regardless of the amount of load to be interrupted beyond the 10 MW threshold level, and regardless of the voltage level of the transmission elements involved in the contingency event(s). As drafted, the Stakeholder Process appears to be silent on receiving approvals to drop load of less than 25 MW. We believe that this is an invitation to trouble for the industry. For example, if a TP or PC were to have a contingency for which the mitigation is to interrupt 15 MW of Firm Demand, all the stakeholders would be called in just to inform them that their load is subject to interruption, but their displeasure is not relevant, because the 25 MW interruption level had not been reached, and approval is not required. Thus, we believe that as drafted Stakeholder Process needs some additional work before we could support it.

Individual

Thad Ness

American Electric Power

Yes

AEP believes it can support the language at this stage, but would like to revisit this after the MW threshold has been determined.

Yes

Yes

No

AEP is concerned that not all Regional Entities are the same in regards to their engineering and planning staff, and is not confident that they would all have the resources necessary to perform the required analysis. AEP is concerned by any attempt to require that a Regional Entity adhere to processes and procedures that have not yet been established. FERC has made comments in the past regarding requirements placed upon regional entities (RRO), and while this standard does not yet apply, it does indirectly obligate them to rules and procedures not yet established.

Individual

John Delucca

LCEC (Lee County Electric Cooperative

"No comment as we have no Firm Demand / Load customers."

No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
No comment as although we are a Firm Demand customer of another entity, we have no Firm Demand / Load customers and therefore would not perform the Stakeholder Process
"None".
Group
MRO NSRF
WILL SMITH
MIDWEST RELIABILITY ORGANIZATION
Yes
The NSRF agrees with the 'x' MW statement in footnote b. The NSRF suggests a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation. To support the inclusion of planning to use up to 300 MW of firm load shedding, registered Transmission Planning entities or regional planning entities should provide a TPL type analysis that demonstrates the use of planned firm load shedding allows BES equipment to stay within emergency thermal, voltage, and frequency ranges, and would not cause instability, uncontrolled separation, and cascading as defined in the FPA Section 215.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote 'b'. In additions, there is no clear justification to indicate that the process with regard to footnote 'b' warrants more prescription stakeholder process details than the rest of the TPL standards. So, the NSRF suggests that Section II be removed. If Section I is not removed, then NSRF suggests at least replacing "all affected stakeholders" with "all known affected stakeholders" or "appropriate known affected stakeholders" because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open to unknown stakeholders or that it notified unknown stakeholders. The use of "all" in mandatory zero defect standards is not appropriate in NERC standards, especially when potential large diverse populations such as affected stakeholders must be considered.
No
Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote 'b'. Stakeholders that participate in stakeholder meeting can ask for any information that they want regarding the proposed use of Firm Demand interruption. They do not need a third party to prescribe what information they need or want. So, the NSRF suggests that Section II be removed. If Section II is not removed, then the NSRF suggests that at least Items 2b, 6, and 8 be removed from the listing. <ul style="list-style-type: none"> <li>Item 2b – The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is basically broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard.</li> <li>Item 6 – The verification of that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements.</li> <li>Item 8 – Potential overlapping uses of footnot 'b' with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, then any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.</li> </ul>
No
The NSRF suggests that Section III be removed for the following reasons. <ul style="list-style-type: none"> <li>The types of transmission</li> </ul>

projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote 'b' are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote 'b' proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote 'b' approval stipulations. • The diversity of applicable regulatory authorities and governing bodies, as well as their justicitional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed Approval stipulations in the TPL-002 standard. If Section III is not removed, then the NSRF suggests the following changes. • Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. • Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. • Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radial fed loads that are much geater that 25 MW and there are no stackholder meetings and required approvals for allowing the loads to be fedd radially (subject to interruption for Category B contingencies) rather than being network fed. The DOE threshold for requiring formal system event analysis is 100 MW of load dropping. So, why should the TPL-002 standard required special approvals to allow less than 100 MW of load be subject to interruption to assure BES reliability? • Change the text of "in Year One of the Planning Assessment" to "in the ten year planning horizon of the Plannign Assessment". The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unforecast load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). • The NSRF is concerned that the current wording, "Corrective Action in Year One of the Planning Assessment" could be interpreted to require an annual stakeholder process review and approval. The NSRF suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner. The NSRF is also concerned about the condition where approval was granted and then removed. Would an entity be instantly non-compliant to the TPL standards? If this is a possibility, the Standard Drafting Team should add a grace period that allows an entity to credibly construct a project to remain compliant.

The NSRF has concerns that over regulation of footnote "b" or "12" could cause lost opportunities for legitimate growth. An example condition would be the development of a large load in a relatively weak transmission area. Many times new large loads need open undeveloped areas to locate. Without the footnote "b" or "12" option, could an entity be forced to turn away legitimate load growth? The key being that an entity could serve the new large load under normal conditions with easy quick upgrades, but would need 5 – 7 years to construct additional transmission to meet N-1 conditions? Therefore the entity would need to turn away new growth because of over regulation on footnote "b" or "12".

Individual

Andrew Z. Pusztai

American Transmission Company

No

ATC agrees with the 'x' MW statement in footnote 'b' , however, supports a maximum threshold value of 300 MW because this is the load loss threshold that the DOE deems to be significant enough to warrant a NERC system event investigation.

No

Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the stakeholder process for the TPL standards, which includes footnote 'b'. In addition, there is no clear justification to indicate that the process with regard to footnote 'b' warrants a more prescriptive stakeholder process than the rest of the TPL standards. So, ATC recommends that Section I be removed. If Section I is not removed,

then ATC suggests replacing “all affected stakeholders” with “all known affected stakeholders” because an entity can develop a list of all known affected entities for compliance purposes and document that the meeting was open to them and that they were notified. An entity cannot demonstrate that a stakeholder meeting is open to unknown stakeholders or that it notified unknown stakeholders. The use of “all” in mandatory zero defect standards is not a good practice, especially when large diverse populations of affected stakeholders are considered.

No

Order 890 already requires Transmission Planners to solicit the input of affected stakeholders on TPL standards. Order 890 does not provide prescriptive details regarding the information that should be included in the stakeholder process for the TPL standards, which includes footnote ‘b’. Stakeholders that participate in stakeholder meetings can ask for any information they want regarding the proposed use of Firm Demand interruption. Therefore, ATC recommends that Section II be removed. If Section II is not removed, then ATC recommends that Items 2b, 6, and 8 be removed from the listing. • Item 2b – The scope and content expectation for an assessment of the potential impact of the proposed Firm Demand interruption on the health, safety, and welfare of the community is broad, nebulous, and vague. The stakeholders would raise any specific, relevant questions or concerns in these areas if they exist without a prescriptive stipulation for this information in the TPL-002 standard. • Item 6 – The verification that the TPL performance requirements will be met by the use of Firm Demand interruption is superfluous. Proposal to use Firm Demand interruption to meet the TPL-002 performance requirements would always be the result of identifying (i.e. verifying) what Firm Demand interruption is needed to meet the TPL-002 performance requirements. • Item 8 – Potential overlapping uses of footnote ‘b’ with adjacent planners will not always exist and would probably be rare. In addition, whenever the situation would exist, any applicable adjacent planners would be affected stakeholders and would have the opportunity to attend the stakeholder meeting and raise any questions or concerns in that meeting without the stipulation of this information in the TPL-002 standard.

No

ATC recommends that Section III be removed for the following reasons. • The types of transmission projects that would be needed to avoid proposing the use of the Firm Demand interruption under footnote ‘b’ are expected to be high cost, long lead time Corrective Action projects. Therefore, consideration of the any necessary approvals from regulatory authorities or governing bodies responsible for approving the Corrective Action project is a prerequisite and essential to any discussion or stipulations regarding disapproval of the use of footnote ‘b’ proposal. The proposed TPL-002 text for Section III does not include any language to address this crucial aspect of any footnote ‘b’ approval stipulations. • The diversity of applicable regulatory authorities and governing bodies, as well as their jurisdictional scope or criteria with respect to the approval of interrupt retail electric service (as well as transmission Corrective Action projects), are too diverse and complex to be appropriately addressed by proposed approval stipulations in the TPL-002 standard. If Section III is not removed, then ATC recommends the following changes. • Include the subject of approvals of Corrective Action projects that are necessary to negate the need for approval of the proposed Firm Demand interruption. • Replace the criteria regarding the voltage level of the relevant Contingency with criteria regarding the amount and type of Firm Demand that would be subject to interruption. The voltage level of the applicable Contingency elements are not material to impact on the affected load. • Replace the applicable amount of Firm Demand interruption criteria from 25 MW to at least 100 MW. There are many radially fed loads that are much greater than 25 MW and there are no stakeholder meetings or required approvals for allowing the loads to be fed radially. The DOE threshold for requiring formal system event analysis is 100 MW. So, ATC believes the TPL-002 standard should not require special approvals to allow less than 100 MW of load to be interrupted to assure BES reliability. • Change the text of “in Year One of the Planning Assessment” to “in the ten year planning horizon of the Planning Assessment”. The planning assessments may reveal that the need to use of Firm Demand interruption will occur in Year 2, Year 3 or beyond (e.g. when a significant previously unexpected load increase is forecast to occur before any needed Corrective Action project could be initiated and implemented). • ATC is concerned that the current wording, “Corrective Action in Year One of the Planning Assessment” could be interpreted to require an annual stakeholder process review and approval. ATC suggests that the standard drafting team provide some language regarding a specific period that is expected for reaffirming the approval of the Firm Demand interruption. A review interval of at least every five years should provide reasonable business

certainty and allow for future transmission construction if needed. The specific defined period of review should allow entities to operate in an effective manner.

Individual

James Tucker

Deseret Generation & Transmission Cooperative

No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.

No

We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

: The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.

Individual

Brian Keel

Salt River Project

No

Additional comment from SRP for Q #5.

The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: "Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read: "The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."

Individual

Andrew Gallo

City of Austin dba Austin Energy

Yes

Yes

No

Some of the information for inclusion in the Stakeholder Process is too burdensome and of limited value. In particular, 2b and 4 can be deleted because the requested information may not be available -- particularly if it is new load growth.

No
The 25 MW threshold for Approval of Interruptions of Firm Demand under Footnote 'b' is too low. It should be increased to 50 MW because there is an elaborate Stakeholder process to work through the reliability concerns.
Individual
Anthony Jablonski
ReliabilityFirst
No
ReliabilityFirst has a major issue/concern with Attachment 1, Section 3 (specifically the last paragraph regarding approval). This section requires the Regional Entity to review each proposed use of Firm Demand interruption under footnote 12 in order to verify that there are no Adverse Reliability Impacts. The paragraph goes on to require the Regional Entity to make its determinations and evaluation of Adverse Reliability Impacts using a published methodology approved by the ERO. First, since the Regional Entity is not a user, owner or operator of the BES, ReliabilityFirst believes the Regional Entity should not have requirements placed upon them. Furthermore there is no guidance on what is required to be placed within the published methodology. ReliabilityFirst believes this verification is outside the Regional Entity scope as delegated by the ERO. ReliabilityFirst believes that if such verification by the Regional Entity is required, it should be specifically laid out in the NERC Rules of Procedure and not an attachment within a standard.
Group
SERC EC Planning Standards Subcommittee
Jim Kelley
PowerSouth Energy Cooperative
No
We do not agree with this approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. If a single contingency results in a local network becoming temporarily radial, then load shedding within the local network should be allowed. A limitation of up to some maximum amount of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process.
No
We recommend using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds are correct. The Stakeholder Process should not even be initiated for less than these threshold levels.
The comments expressed herein represent a consensus of the views of the above-named members of the SERC EC Planning Standards Subcommittee only and should not be construed as the position of SERC Reliability Corporation, its board, or its officers.
Individual
Kayleigh Wilkerson
Lincoln Electric System
No
LES suggests the following changes to Footnote B/12 to further clarify the drafting team's intent. Under Footnote B/12, recommend the first sentence be modified to state "An objective of the planning

process is to minimize the likelihood and magnitude of interruption...". Additionally, please clarify the reference to the Near-Term Transmission Planning Horizon while remaining silent on the Long-Term Transmission Planning Horizon. Does Appendix 1 apply to the Long-Term Transmission Planning Horizon as well as the Near-Term Transmission Planning Horizon?

Yes

Although LES agrees in general with the description and components included as part of Section I, we suggest the following wording changes to enhance Section I. Recommend the drafting team delete item 2(c) as it is duplicative of item 4 which is more succinctly worded. Also, recommend additional wording be added to the end of item 3 to provide meeting participants with advanced notice of the information. As an example, "information...must be made available to meeting participants [ten days prior to the meeting]."

Yes

No

For item 1(b) in Section III, LES requests that the drafting team clarify why approval by the regulatory authority for a generator contingency is based on the high-side voltage of the GSU rather than the generator capacity. LES believes the generator capacity, rather than the high-side voltage of the GSU, provides a more consistent basis for determining necessity for approval from the applicable regulatory authority or governing body. Additionally, LES asks for further clarification as to whether the steps referenced for Year One of the Planning Assessment extend to Year Two and beyond.

Individual

Milorad Papic

Idaho Power Co.

Yes

Maximum threshold for Planned Firm Demand interruption should be based on a previous year recorded peak demand. For instance for recorded peak demand of more than 3,000 MW the maximum threshold should be greater than 300 MW.

Yes

Yes

Yes

Individual

Martyn Turner`

LCRA Transmission Services Corporation

No

Footnote 12 is applied in column labeled "Non-Consequential Load Loss Allowed." However, the last sentence of the proposed Footnote 12 switches from using the terms Consequential Load Loss and Non-Consequential Load Loss to using the term "Firm Demand." The term "Firm Demand" should be revised to "non-Consequential Load Loss." In addition, the application of Footnote 12 to the P3 contingency category should be removed.

No

In the Proposed Revision to the Standard, Footnote 12 is applicable to the use of Non-Consequential Load Loss to relieve criteria violations resulting from P1, P2, and P3 category contingencies, however, Footnote 12 and Attachment I switch terms and begins using "Firm Demand." Though it may be reasonable to characterize Non-Consequential Load Loss as a subset of Firm Demand not all Firm Demand is Non-Consequential Load Loss. The term "Firm Demand" as used in Footnote 12 and Attachment I should be replaced with "Non-Consequential Load Loss." Application of the term "Firm Demand" in Footnote 12 and Attachment 1 introduces an economic criteria to the TPL-001 Reliability Standard. For instance, the interruption of "Firm Demand" as defined in the NERC Glossary may not

require Non-Consequential Load Loss, however, this is an economic decision between the parties involved in the Firm Demand contract. In addition, a Transmission Planner or Transmission Owner may or may not be a party to the Firm Demand contract. The process outlined in Attachment 1 applies to the P3 contingency category (through the application of Footnote 12) and thus represents a significant and substantive change in the reliability standard over previous standards. The reference to Footnote 12 should be deleted from the P3 contingency category.

No

Requirement 1 only requires that the Transmission Planner provide system load data, however, assumptions about system dispatch are also relevant. Requiring load without dispatch will not provide a complete understanding of the conditions under which Footnote 12 will apply. As a reliability standard, the Transmission Planner is required to find a range of plausible system conditions under which a criteria violation may be resolved. The requirement (1a) to provide an estimate of the exposure creates an overly burdensome requirement to investigate a wider range of possible operating conditions than is currently performed. Requirement 2a and 2b are overly burdensome on a Transmission Planner/Transmission Owner who does not directly serve retail loads by placing a requirement on the Transmission Planner/Transmission Owner to provide data that is outside of its control to develop or maintain.

No

See previous comments about use of the term "Firm Demand".

The primary objection to Footnote 12 is twofold: 1. Application to the P3 contingency. This contingency is a Category C contingency under the current NERC TPL-003 standard and allows for load shedding. Thus, the proposed standard revision is a significant and substantial increase in the reliability standard. 2. Use of the term "Firm Demand" as opposed to "Non-Consequential Load Loss." The NERC Glossary defines Firm Demand as "That portion of the Demand that a power supplier is obligated to provide except when system reliability is threatened or during emergency conditions" and Demand as "The rate at which electric energy is delivered to or by a system or part of a system, generally expressed in kilowatts or megawatts, at a given instant or averaged over any designated interval of time." Thus interruption of Firm Demand may not result in Non-Consequential Load Loss. Term "Firm Demand" should be replaced with "Non-Consequential Load Loss."

Group

Southern Company

Antonio Grayson

Operations Compliance

No

Southern does not agree with this Stakeholder Process approach since there is no technical basis for allowing load shedding. It is all an administrative process which could result in inconsistencies from area to area. A more technical based approach was the one taken by the SDT in an earlier draft - temporarily radial concept. If a single contingency (Category B) results in a local network becoming temporarily radial, then load shedding within the local network should be allowed since it would not have any impact to the reliability of the transmission grid. A limitation of up to some maximum amount ('x' MW) of load shedding (to be determined) should be imposed. This would provide a technical basis for load shedding, which would help ensure consistency from area to area. Furthermore, this would provide a method for defining the "fringes" of the power system.

No

Southern recommends using a technical basis for load shedding (see comment in Question 1 above) instead of a Stakeholder Process.

No

Southern recommends using a technical basis for load shedding instead of a Stakeholder Process.

No

Southern recommends using a technical basis for load shedding instead of a Stakeholder Process. However, if a Stakeholder Process is used, the approval thresholds given in the draft seem appropriate. Furthermore, we believe the Stakeholder Process should not even be initiated for less than these threshold levels. Lower amounts of load and lower voltage contingencies do not need to be taken through a Stakeholder Process.

The use of load dropping should be limited to being only an interim solution while a project is being completed and nothing else can be done.

Individual

Jonathan Fidrych

Tri-State Generation & Transmission Association, Inc.

No

There are several points that we disagree with in terms of the Stakeholder Process in the body of the footnote. First, the footnotes are not written in a manner so as to clearly be only applicable to Planning Standards. Many parts of the footnotes and the Attachment I can be misconstrued as Operational requirements. For example, the sentence that states "Curtailed of firm transfer..." should state "Planned curtailment of firm transfer..." Second, we disagree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest removal of this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Lastly, in an effort to develop a clearer and more transparent compliance standard, it is recommended that the additional requirements imposed by this footnote be broken into separate requirements set forth within the body of the standard itself. Do not imbed requirements in footnotes.

No

We disagree with Section I of Attachment I to the extent that there currently are several other venues through which stakeholder input is mandated. In addition, we do not believe NERC Reliability Standards have the authority to dictate stakeholder outreach processes. For several reasons, including the time required for public input, permitting, acquisition, and construction, most transmission projects take several years to build. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The Footnotes do not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests.

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

We disagree with the instances for which Approval of Interruptions is required as proposed by Section III of Attachment I. TPs will develop plans to mitigate BES performance violations, but those plans may not be able to be constructed in time. The reason being that the time required to construct a project to mitigate the issues can take several years. This is due to the need for public input, permitting, acquisition, and construction. Attachment I does not allow planners to design temporary mitigation to accommodate real world construction issues, which are often complex in nature due to competing interests. Attachment I also states that "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..." The need for approval seems burdensome such that it does not allow for temporary mitigation to meet BES performance criterion while other avenues are explored and vetted. The intent

of Section III is genuine, but we feel that it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load.

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.

Group

Arizona Public Service Company

Janet Smith

Arizona Public Service Company

Yes

Yes

Yes

No

AZPS does not agree that approval 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 approval. There would be no adverse affect of non-consequential load tripping on the BES. No reason for Reginal Entity involvement.

This process is too prescriptive and must be simplified.

Individual

John Martinsen

Public Utility District No. 1 of Snohomish County

No

No

No

No

Comments: SNPD generally disagrees with the draft process that has been developed, and notes that infrequent interruption of small amounts of non-consequential load under limited conditions that does

not negatively impact a neighboring TOP is not a reliability issue. Instead it is a cost of service and customer service matter best left to the local and state regulatory bodies. The time and resources spent on this issue at the national level diverts scarce resources and attention from more important efforts that might actually benefit the reliability of the BES. SNPD supports the Pacificorp Revision of TPL-002 footnote 'b' and TPL-001 footnote 1 Comments- The proposed revisions will require regulatory approval for 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 or equal to 25 MW. The 2011 peak winter and summer loads in the Western Electricity Coordinating Council (WECC) region were 131,471 and 152,211 MW respectively. Total installed generation is 229,189 MW. There are 120,385 miles of AC transmission lines 100 kV and above, and of that total, 31,138 miles of AC transmission lines are operated at voltages above 300 kV. There are 1,744 miles of DC transmission lines. The proposed revisions would add considerable process and documentation for any interruptions, and will require regulatory approval if the interruption is greater than 25 MW. This is 0.016 percent of the WECC peak load. The planning standards already require Category B1 contingencies to be considered which result in the loss of a single generator since individual generator units range in size up to more than 1000 MW. Since these contingencies are routinely studied, it is very, very difficult to imagine that the loss of 25 MW or more of firm demand under TPL-002 footnote b or TPL-001 footnote 12 is so critical to the reliability of the BES that it deserves not only a lengthy footnote, but a two page attachment detailing a complex and lengthy process detailing requirements public meetings, procedures for questions, specifications for documentation, and even a dispute resolution process. As this is not a BES reliability issue, any action regarding potential curtailments of local loads should occur at the local level where the cost and benefit of improvements can be properly assessed. The recent blackout that left 2.7 million customers in Southern California, Arizona and Baja California without power was not due to planned or controlled interruption of electric supply where a single contingency occurs on a transmission system. SNPD is not aware of any regional disturbances or cascading events that were due to planned or controlled interruptions of electric supply where a single contingency occurred on a transmission system. As these proposed requirements could be removed from the Reliability Standards with little or no effect on reliability and would, if anything, increase the efficiency of the ERO compliance program, the proposed limitations on curtailment of firm demand under TPL-002 footnote b or TPL-001 footnote 12 should be removed.

Individual

Robert W. Creighton

Nova Scotia Power

Yes

Yes

Yes

Yes

With regard to the application of Footnote 12 in TPL-001-3, the footnote is only applied to the contingencies in Table 1 involving loss of a Single Line with a 3 phase fault (P1) or opening of a line without a fault (P2-1). These are higher probability events relative to other types of contingencies, and Footnote 12 allows for loss of load for these events, but does not allow for loss of load for lower probability events that have the same results, such as P2-2 and P2-3. Take for example a single radial 345kV line feeding a small radial portion of the system, with a line end transformer and breaker between the transformer and the line. Application of Footnote 12 to only a P1 event (loss of the line on its own, or loss of the transformer on its own) but loss of the breaker between the line and the transformer would not be allowed, even though the result would be the same. Without applying footnote 12 to category P2-2 and P2-3 would mean that Footnote 12 is rendered moot (can never be used). Similarly, Footnote 12 should be applied to P4 and P5, essentially wherever Footnote 9 is applied, otherwise Footnote 12 can never be applied.

Individual

Greg Rowland
Duke Energy
Yes
Situations where use of footnote 'b' would be appropriate can't be readily characterized with criteria leading to some "technically justified" maximum capacity threshold for interruption. That being the case, a maximum capacity threshold could be established based upon other criteria, such as the 300 megawatt threshold for DOE disturbance reporting.
No
Since item 2 describes the public notice that must be provided, the phrasing of 2.b should be revised to replace the words "Specific applications" with the words "Summary description". "Specific applications" could be considered to require detailed descriptions of each and every contingency that could lead to use of footnote 'b'. That level of detail could certainly be provided to meeting participants, but shouldn't be necessary for the public notice.
No
In Item #8, replace the word "planners" with the words "Transmission Planners".
No
Section III is confusing. Are the last two paragraphs of Attachment 1 supposed to be part of Section III? These paragraphs, when read in combination with the first paragraph of Attachment 1, seem to say that any time a Firm Demand interruption using footnote 'b' or footnote 12 shows up in the Near-Term Transmission Planning Horizon, the Stakeholder Process must be invoked. It would seem more reasonable to invoke the Stakeholder Process only when such interruption occurs in Year One of the Planning Assessment.
Individual
Chris de Graffenried
Consolidate Edison Co. of NY, Inc.
No
See reply to Question 5
No
See reply to Question 5
No
See reply to Question 5
No
See reply to Question 5
Planned interruptions of Firm Demand in response to a Single Contingency (as directed in Footnote b of TPL-002 Table 1, is not an acceptable corrective action to mitigate reliability issues on the BES system. The Interconnected System should be designed and operated with enough transfer capacity to be able to withstand, at a minimum, a single contingency event without service interruptions to customer load. Systems must be designed and operated so that the impact of any single contingency can be mitigated by re-dispatching available system resources without the need to implement load shedding.
Individual
Charlie Pottey
Sierra Pacific Power Co d/b/a NV Energy
Individual
Richard Vine
California Independent System Operator
No
We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number

cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount. We support the description and components of the Stakeholder Process in the body of the footnote, but do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability, as explained above. Also, we have comments on the reference to Attachment I. Please see our comments under Q5.

No

The process presented in Section I of Attachment I is overly prescriptive. Identifying the need for stakeholder consultation on this issue within the consultation process already employed by the Transmission Planner or Planning Coordinator should be sufficient detail. In particular, however, we suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution? 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 leaves the time frame wide open, and does not explicitly or implicitly 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. 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 removing the word “Near-Term”.

No

This Section is overly prescriptive. This Section needs only to stipulate at a high level, the kind of information needed to support the proposed utilization of footnote b and footnote 12. In particular, we disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.

No

We do not agree with the requirement to seek regulatory authority approval or Regional Entity approval. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements (which provide no reliability benefit or basis) in a reliability standard. NERC reliability standards should focus only on BES reliability, not on any regulatory requirements. A notification process should be sufficient. It is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues for approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As

stated in this questionnaire, 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It would be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) would be duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8). What type of review and verification would be required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint"?

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The process described in Attachment 1 may be more suited for inclusion in the Rules of Procedure, similar to the process required for seeking BES facility exceptions. We urge the SDT to consider moving Attachment 1 into a proposed RoP instead of stipulating it in the standard.

Individual

charlie pottey

nevada power company dba nvenergy

No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.

No

We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many

affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.

Group

Western Area Power Administration

Brandy A. Dunn

Western Area Power Administration (Corp. Services Office)

No

The addition of the "Stakeholder Process" outlines in Attachment 1 is so onerous so as to persuade entities NOT to attempt the use of Footnote b) OR 12). Is this the intent?

Individual
Si Truc PHAN
Hydro-Quebec TransEnergie
No
Comments: It is difficult to establish the maximum value for acceptable Firm Demand interruption. For example, an entity may have an acceptable maximum load loss to avoid impacts on the grid such as generation trip-outs. For Hydro-Québec TransÉnergie (HQT), in the Québec Interconnection, this value is above 1,000 MW. No maximum value should be posted in Footnotes 12 and 'b', since it is specifically related to system design and Interconnection size (inertia). Let us keep in mind that the goal of the TPL standards is not service continuity of local loads but global reliability of the system. Even though service continuity is important, TPL standards should not address this issue by posting a maximum allowable load loss. Moreover, HQT considers that a Stakeholder Process such as seen in Attachment I has no place in a standard and its footnotes. Mainly, the Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish this load loss value.
No
The Stakeholder Process doesn't consider that entities may have their own regulatory authorities with different processes, which do not specifically establish load loss values. Also, the use of Firm Demand interruption in the Corrective Plan should not be limited only to the Near-Term Transmission Planning Horizon. It should also be allowed for the Long-Term horizon, at least for Multiple Contingencies.
No
For example, under 2 b., assessment of the impacts of interruptions on health, safety, or welfare of the community is not information that could be reasonably expected to be available to system planners. All loads may face interruptions from time to time, and the impact on health, safety or welfare is very difficult to identify. This item should be deleted.
No
For example, in 1a., it is not clear what is meant by "the stated performance criteria regarding allowances...". Why is it necessary to give this kind of explanation? In 1b., the use of the term "non-generator step up transformer" is unusual. Suggest rewording 1b to read: For a generator or generator step up transformer outage Contingency, the extra high voltage (EHV) limit applies to the BES connected voltage (high-side of the Generator Step Up transformer). For any other transformer outage Contingency, the EHV limit applies to the low-side winding (excluding tertiary windings).
Footnote 12 is not applied to Categories P4 and P5, which would include a EHV stuck breaker or failure of a non-redundant relay for a Multiple Contingency. The Load loss restriction for the contingencies listed in P4 and P5 is more restrictive than for the loss of a EHV double circuit line. Statistics indicate that the contingencies presented in P4 and P5 are less frequent. HQT requests that Footnote 12 should also be used for P4 and P5 contingencies for EHV. Even though considering Firm Demand interruption in planning might not be common practice, HQT agrees that the proposed Footnote 12 should maintain such a possibility.
Individual
Chris Scanlon
Exelon
No
For TPL-001, the wording for footnote 12 does not make clear that DSM would be allowed without the Attachment 1 procedure. ComEd suggests the following wording change: 12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements (other than Interruptible or Demand Side Management load), such interruption is limited to circumstances where the Non-Consequential Load Loss is meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW. For TPL-002, the wording of

footnote "b" is not totally clear that it applies only to non-consequential load shed and not consequential load shed. ComEd suggests that the wording of footnote "b" be changed as shown: b) An objective of the planning process should be 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. Furthermore, in limited circumstances Firm Demand may need to be interrupted to ensure that BES performance requirements are met. When interruption of Firm Demand (other than in (1) or (2) above) is utilized within the planning process 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 'x' MW.

Individual

Catherine Mathews

NorthWestern Energy (NWMET)

No

Comments: A fixed maximum number of MW for Non-Consequential Load Loss should not be used in an industry-wide standard. There is too much diversity. We suggest that a fixed maximum number not be stipulated.

No

Comments: It is unclear how the dispute resolution process would treat stakeholders with different concerns. We suggest that Item 5 of Attachment 1 be deleted.

No

Comments: The estimated number and type of customers affected is not needed for reliability of the Bulk Power System. We suggest removing Item 2a in Section II of Attachment 1. An assessment of the health, safety, and welfare of the community should not be required. It is too vague and could present legal problems. We suggest removing Item 2b in Section II of Attachment 1.

No

Comments: A NERC Standard should not require action from a regulatory authority to approve the use of Firm Demand interruption. There is too much diversity in regulatory authorities over the industry-wide area. This would increase the work load of the Regional Entities without improving reliability. We suggest removing Section III of Attachment 1.

Comments: Footnote 12 should be added to Category P2 Single Contingency Event 2, Bus Section Fault, and to Category P2 Single Contingency Event 3, Internal Breaker Fault, for EHV in the Non-Consequential Load Loss column.

Individual

Robert Casey

Georgia Transmission Corporation

Yes

Please remove the "is" as shown below: "12. An objective of the planning process should be to minimize the likelihood and magnitude of Non-Consequential Load Loss following Contingency events. However, in limited circumstances Non-Consequential Load Loss may be needed to ensure that BES performance requirements are met. When Non-Consequential Load Loss is utilized within the planning process to address BES performance requirements, such interruption is limited to circumstances where the Non-Consequential Load Loss [IS] meets the conditions shown in Attachment 1. In no case can the planned Firm Demand interruption under footnote 12 exceed 'x' MW."

No
Item #1 in Section I should be reworded: From This...“Meetings must be open to all affected stakeholders including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” Reworded to say: “Meetings must be open to all affected NERC Registered Entities including applicable regulatory authorities or governing bodies responsible for retail electric service issues.” The concern is that stakeholders could be too broadly construed including residential, commercial, industrial customers, and even more so (i.e transitory customers). We recommend that the sentence be reworded as shown above. Additionally, GTC request feedback from the SDT’s intent. Is a stakeholder meeting required every year a planning assessment is done showing that non-consequential load loss is required?
No
GTC does not understand how item #2b of Section II pertains to the Transmission Planner or the Planning Coordinator. These types of assessments are beyond the scope of the Transmission Planner or the Planning Coordinator and if necessary, should possibly be done by the Load Serving Entity. GTC Recommends the SDT remove item #2b, the following sentence: “An assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community.”
No
GTC would appreciate if the SDT could please clarify if the approval of a regulatory authority or governing body is referring to the Regional Entity. The first sentence in Section III: “Approval of the use of Firm Demand interruption under footnote 12 by the applicable regulatory authority or governing body responsible for retail electric service issues is required if either:...”
The current draft for Requirement 5 (R5) of the NERC Standard TPL-001-3 Draft 1 reads as follows: “Each Transmission Planner and Planning Coordinator shall have criteria for acceptable System steady state voltage limits, post-Contingency voltage deviations, and the transient voltage response for its System. For transient voltage response, the criteria shall at a minimum, specify a low voltage level and a maximum length of time that transient voltages may remain below that level.” GTC has the following comments regarding TPL-001-3, R5: If the responsible entity has criteria for transient voltage response, along with criteria for acceptable system steady state voltage (including a pre-contingency high and low voltage limit, and a post-contingency high and low voltage limit), then having a steady state post-contingency voltage deviation criteria does not affect the reliability of the bulk electric system (BES). If the system response to a disturbance were to violate either the transient response criteria, or the steady state maximum/minimum voltage criteria, there is potential for loss of integrity of the BES. There is little to no potential for a loss of system integrity due solely to a violation of the steady state voltage deviation criteria. Therefore, Georgia Transmission Corporation requests that R5 not include a requirement to have criteria for post-Contingency voltage deviations.
Individual
Kathleen Goodman
ISO New England Inc.
No
For single contingency events, footnote 12 should be eliminated. Planning the electric system for non-consequential load loss as a means to address a single contingency should not be acceptable. If the footnote is to remain, as a minimum the attachment should be changed to increase the emphasis on the near term nature of the use of non-consequential load shedding.
No
With regard to Section I, in paragraph I.5, the stakeholder process includes a dispute resolution process. Existing ISO/RTO stakeholder processes are FERC approved and rigorous, requiring a dispute resolution process goes beyond the existing requirements in ISO/RTO tariffs. Item I.5 should be eliminated.
No
Section II, Paragraph 2b requires “an assessment of the use of Firm Demand interruption under footnote 12 on the health, safety, and welfare of the community”. A great deal of subjectivity and information that is not readily available to the Transmission Planner or Planning Coordinator would be required to accurately access the effect of load shedding on the community as required by 2b. Additionally Paragraphs II.3 and 4 require estimates of the frequency and duration of Firm Demand interruption would be difficult to provide. These requirements should be deleted. These requirements

also undermine the deterministic nature of the Planning Standard. Paragraph II.2.5 that requires future plans to mitigate the need for Firm Demand Interruption should be modified to again emphasize the near term nature of single contingency non-consequential load shedding as a Planning option.

No

Section III describes the instances where Approval of Interruptions of Firm Demand are required under footnote 12. It is not clear whether under Paragraph III.1.a and Paragraph III.1.b the Transmission Planner is to base the determination on either contingency or both contingencies i.e. is "and" logic to be applied or is "or" logic used? Paragraph III.2 requires such approval for interruption equal to or greater than 25 MW, this is a very small amount of load to be required to bring to a stakeholder approval process for second contingency events. This amount should be increased to at least 100 MW. Additionally in Section III, it is not clear who the "regulatory authority or governing body responsible for retail electric service issues" is. Having this requirement in a reliability standard not only is unnecessary, but also introduces regulatory requirements in a reliability standard. NERC reliability standards should focus only on BES reliability, not any regulatory requirements. The Attachment goes on to state "The Regional Entity determinations of Adverse Reliability Impacts are to be evaluated by the Regional Entity through a published methodology approved by the ERO". This is essentially a "fill in the blank" requirement and makes it necessary to comment and approve the footnote attachment without the benefit of reviewing a proposed methodology.

Individual

Bangalore Vijayraghavan

PG&E Company

No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of this footnote states, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events". It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fixed maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving "safe harbor" to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the "not to exceed" amount.

No

We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision

by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV in P1 is of no value. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 3 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column.

Individual

RoLynda Shumpert

South Carolina Electric and Gas

No

SCE&G does not agree with the proposed modifications to footnote b. SCE&G believes the original footnote b is appropriate and consistent with the Energy Policy Act of 2005. SCE&G cites several statements in the Energy Policy Act of 2005 as justification for our position. 1. The Energy Policy Act of 2005 states: "The term 'reliability standard' means a requirement, approved by the Commission under this section, to provide for reliable operation of the bulk-power system. The term includes requirements for the operation of existing bulk-power system facilities, including cybersecurity protection, and the design of planned additions or modifications to such facilities to the extent necessary to provide for reliable operation of the bulk-power system, but the term does not include any requirement to enlarge such facilities or to construct new transmission capacity or generation capacity." It also states, "This section does not authorize the ERO or the Commission to order the construction of additional generation or transmission capacity or to set and enforce compliance with standards for adequacy or safety of electric facilities or services." SCE&G believes the proposed modifications to footnote b will result in building or enlarging facilities to meet the proposed requirements. Also, any requirement that disallows load interruption or limits the amount of load interruption infringes on the stated limitation on the ERO to not set and enforce compliance with standards for adequacy. 2. It also states: The term 'reliable operation' means operating the elements of the bulk-power system within equipment and electric 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." In this statement there is no mention of disallowing the interruption of firm load. It only requires that instability, uncontrolled separation, or cascading failures not occur. SCE&G believes the proposed changes to footnote b are beyond the authority granted to the ERO by the Energy Policy Act. 3. It also states: "Nothing in this section shall be construed to preempt any authority of any State to take action to ensure the safety, adequacy, and reliability of electric service within that State, as long as such action is not inconsistent with any reliability standard, ..." SCE&G believes the proposed modifications to footnote b infringe on the state's authority to address adequacy and reliability of electric service within the State.

No

See response to question #1

No

See response to question #1

No

See response to question #1

none

Group

ACES Power Member Standards Collaborators

Jason Marshall

ACES Power Marketing

No

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 such a 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?

No

(1) Attachment 1 should clarify that it only applies when approval is not required by the regulatory body with authority over retail service, such as local regulatory authorities and state public utility commissions. This includes whether the approval is required by NERC rules or another regulatory body's rules. It does not make sense for the Transmission Planner or Planning Coordinator to duplicate a process that is already required by another regulatory body that satisfies due process. As an example, why should the Transmission Planner and Planning Coordinator have a dispute resolution process if the regulatory body already has a dispute resolution process that can be used. It also does not make sense for the Transmission Planner and Planning Coordinator to be compelled to have a stakeholder comment process when the local regulatory body's approval is required. Having such a process is duplicative and unnecessary. (2) Many RTOs have well organized stakeholder processes that could be utilized to satisfy Attachment I. Because the TPL standards apply to both the PC and TP, one may believe the both the PC and TP need to have these stakeholder processes. Rather, we think that the TP should be able to rely on its PC's stakeholder process. We suggest Attachment I should clarify that this is acceptable 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) We disagree with including the Facilities that will exceed their rating and the applicable contingencies. We think this information should be treated as confidential. It could be used by bad actors to create outages within communities. The risk to the Bulk Electric System is higher than the benefit of sharing this information. (2) We disagree that the Transmission Planner should be required to provide an assessment on the health, safety and welfare of the community. First, the stakeholders will have an opportunity to provide this information through either the Transmission Planner's stakeholder comment process or through the local regulatory agency's stakeholder comment process. Second, these planned interruptions in firm demand are expected to be short in nature so the impacts

should be minimal. Third, an assessment on the health, safety and welfare of the community is an unnecessary burden on the utility and is better suited for local governments. Even if the utility should perform such an assessment, health, safety and welfare are ambiguous terms without clear parameters or expectations for the data. Does this mean that the Transmission Planner verifies police stations, fire departments, hospitals and other critical public support agencies are not included in the planned load shed? Most electric providers already do this when developing load shed plans and are likely not going to include such customers in any load shed plan. Fourth, communities already have plans in place for the interruption of electricity so as long as critical customers are not shed, then the impacts are likely economic in nature. (3) Bullet 3 needs to be clarified that it is not an estimated frequency but rather a historical frequency. How do you estimate a frequency for a new planned load shed? It also needs to be clarified if the historical frequency is all instances within the Transmission Planner's area or just the specific location of the planned load shed. If it is all instances, it further needs to be clarified that it is only within its own TP area. (4) We do not believe that expected duration of the planned load shed should be required. Any duration will likely be a guess. When actual contingencies occur, the time of restoration varies. Consider the recent event in Arizona and Southern California. The report indicated that the TOP thought they could return the 500 kV line that initiated the event in a few minutes. They were unaware that the phase angle was too large to close. The expected duration is too speculative and should not be required. (5) We disagree with the need to include future plans to mitigate the planned load shed in all cases. For remote areas of the system, there simply may not be sufficient load growth to justify any other mitigation. (6) Item 8 should be clarified that it applies only to the Planning Coordinator. The Planning Coordinator should coordinate all of its Transmission Planner's Planning Assessments. This would include evaluating planned load shedding.

No

(1) What is the justification for selecting a 300 kV contingency as a threshold for requiring local regulatory agency approval? What if the planned load shed is only for 1 MW? If a threshold is required, we think it should be based on load size rather than contingency size? (2) What is the justification for selecting 25 MW of planned firm load interruption as a threshold for requiring local regulatory approval? The threshold could be set based off of the accompanying Section 1600 data request. Since there are likely not many instances, it could be required for any new instance that exceeds the existing planned load shed amounts. Thus, the threshold would be set just above existing planned load interruptions. (3) A disclaimer should be added to clarify that an entity may still have to seek local regulatory agency approval per the local regulatory agency's rules. Nothing in the NERC standard will change the local regulatory agency's rules. (4) What if the local regulatory agency does not want to address the planned load shed in the planning time frame? What is the Transmission Planner required to do? While it is likely a local regulatory agency would be interested in addressing a planned load interruption, nothing in the NERC or Commission rules can compel a local regulatory agency to address such matters in a specific time frame. (5) Bullet 1.a is confusing. Is it intended to say that if two Elements are part of a contingency and the Elements have different voltage classes, the Element with the lowest voltage class must exceed the 300 kV threshold? If this is the case, the bullet needs further clarification because it does not state this clearly. (6) The first paragraph after section III appears to contradict bullets 1 and 2. Bullets 1 and 2 place contingency and load thresholds on the planned firm load interruption. However, this paragraph says that the regulatory body responsible for retail electric service must approve the planned load shed before it can be used in Year One of the planning assessment. If the purpose is for the thresholds to apply beyond Year One and any instance in Year One to require approval, then the language regarding the thresholds needs to clarify that the thresholds apply beyond Year One only. (7) We think it is redundant for the Regional Entity to evaluate planned interruptions of firm load in its footprint. The Planning Coordinator has a wide area view and is already required to do this for its footprint. The Planning Coordinator already works with its neighbors to evaluate impacts. Requiring this evaluation by the Regional Entities is arbitrarily based on historical and political boundaries. Many Planning Coordinators have views that are broader than the Regional Entity view because they are in multiple regions. If this evaluation will be required on a regional basis, why won't it be required on an interconnection? (8) The evaluation required by the Regional Entity may be completed before planned load interruption is approved by local regulatory body. The TP and PC must submit the data based on their plan before the local regulatory body approves the planned load interruption. The Regional Entity must complete its evaluation within 45 days of receiving the information. There is no obligation for the local regulatory body to act within 45 days. Wouldn't it make more sense to evaluate the planned load

shed after it is approved by the local regulatory body?

(1) 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 great effort and resources be expended in year five when another solution will likely be developed? (2) This standard does not consider if the local regulatory body will act in time to approve the use of planned Firm Demand interruption. We believe the standard needs to consider that the Planning Coordinator and Transmission Planner may not be able to control the timelines of local regulatory agencies. As long as the PC and TP have done their part by submitting the data, they should be able to rely on the planned Firm Demand interruption until the local regulatory body acts. If the planned Firm Demand interruption is not approved, then the TP and PC should be given more time to address the transmission performance deficiency. (3) Several terms are used for the use of planned load shed. Non-consequential load loss and Firm Demand interruption are two examples. We suggest using one term consistently throughout the standard.

Individual

Steve Myers

Electric Reliability Council of Texas, Inc.

No

As an initial matter, ERCOT does not believe the planning process should allow for non-consequential load shedding under single contingency conditions. However, 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. 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.

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). 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. An assessment 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' with adjacent planners (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 criteria. As such, there is no need for the proposed stakeholder process, including the Section III instances requiring regulatory approval. 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 ¶ 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

Ed O'Brien

Modesto Irrigation District

No

We do not agree with the concept of non-consequential load loss in light of historic application of N-1 criteria, that only provides for consequential load loss.

No

We suggest removing item 5, "A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder's satisfaction". Given that the "applicable regulatory authorities or governing bodies responsible for retail electric service issues" are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote 'b' on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which make compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the "applicable regulatory authorities or governing bodies responsible for retail electric service issues".

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues

to approval of the use of Firm Demand interruption under footnote 'b'. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote 'b' (see Section II.6) and the assessment of potential overlapping uses of footnote 'b' with adjacent planners" (see Section II.8), it is hard to imagine what type of review and verification is required to show that "there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity's footprint".

Group

Bonneville Power Administration

Chris Higgins

Transmission Reliability Program

No

BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. As stated in the proposed footnote b, "[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events." Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases. Moreover, a quantitative limit would be difficult to implement due to the wide variety of system configurations and conditions. BPA believes an appropriate amount would be dependent on the topography and the size of the system being planned.

No

Regarding the stakeholder process and dispute resolution, BPA believes that a decision for Firm Demand interruption needs to be made based on what is best for the system, not a specific dispute resolution process.

No

BPA does not support including information under Sections II.2.a and II.2.b, estimated number and type of customers affected, or an assessment of the use of Firm Demand interruption on the health, safety, and welfare of the community as this information does not support reliability of the BES. If footnote b were applied, reliability of the BES is actually assessed by meeting the applicable TPL Standard for a single contingency with loss of load regardless of the type of customers or use of Firm Demand.

No

Regarding Section III.2 as stated above, BPA does not support quantitative limits on planned interruption, as planners generally do not plan the system to interrupt demand for a single contingency. Setting a quantitative limit would push transmission planners to plan the system to meet such a limit for a single contingency in all cases.

Individual

R. Peter Mackin

Utility System Efficiencies, Inc.

No

We do not agree with the imposition of a maximum limit on the amount of planned Firm Demand interruption under footnote b. This addition is overly prescriptive, unnecessary, and can have unintended consequences on service reliability. We suggest deleting this sentence. Assigning a fixed "not to exceed" number of MW in a continent-wide standard is overly prescriptive. A single number cannot account for variation even within one BA Area. This number will be too high for some planning systems and too low for others. A fixed maximum number of MW for Non-Consequential Load Loss under Footnote b in TPL-002 (and footnote 12 in TPL-001-3) is not necessary. The first sentence of

this footnote states, “[a]n objective of the planning process should be to minimize the likelihood and magnitude of interruption of firm transfers or Firm Demand following Contingency events”. It is clear that the spirit of the TPL Standard is to minimize the likelihood and magnitude of Firm Demand interruption. Adding a fix maximum number of MW would seem unnecessary at best. At worst, it could have unintended consequences. Without a fixed maximum Non-Consequential Load Loss, the Transmission Planner understands that the objective is to minimize the magnitude of the planned interruption under footnote b (TPL-001-3, footnote 12). Adding a maximum number of MW of planned Firm Demand loss could have the effect of giving “safe harbor” to allow planned loss of that amount of load under Footnote b. The Transmission Planner may now have more difficulty in avoiding Non-Consequential Firm Demand Loss that is less than the “not to exceed” amount.

No

We suggest removing item 5, “A dispute resolution process for any question or concern raised in #4 above that is not resolved to the stakeholder’s satisfaction”. Given that the “applicable regulatory authorities or governing bodies responsible for retail electric service issues” are only one of the many affected stakeholders, it is unclear how this dispute resolution process would treat stakeholders with different concerns. For example, how would such a dispute resolution process take into account the cost-benefit balance of load loss, which is the responsibility of the authorities responsible for retail rates, if such an authority is only one of the many stakeholders subject to dispute resolution?

No

We disagree with the inclusion of the information in Section II.2.a (the estimated number and type of customers affected) and II.2.b (An assessment of the use of Firm Demand interruption under footnote ‘b’ on the health, safety, and welfare of the community). We suggest removing them. Section II.2.a is an administrative process and not needed for reliability of the Bulk Power System. Section II.2.b is vague and can be interpreted numerous ways, which makes compliance difficult. It can also become a legal liability issue for the service provider, even if that loss of load is judged to be a prudent decision by the “applicable regulatory authorities or governing bodies responsible for retail electric service issues”.

No

While we do not disagree with the intent, it is over-reaching for a NERC Standard to require action from the applicable regulatory authority or governing body responsible for retail electric service issues to approval of the use of Firm Demand interruption under footnote ‘b’. In any case, using 25 MW as the threshold of loss of Non-Consequential Firm Demand for requiring approval is not realistic. As stated in this questionnaire 25 MW came from registration limit for generation in the ERO Statement of Compliance Registry Criteria. It will be a stretch to apply this value to load. Requiring the Regional Entity to approve the Non-Consequential Load Loss under footnote b in TPL-002 (Footnote 12 in TPL-001-3) is duplicative and would increase the work load of the Regional Entities without improving reliability. The TP and PC are already required to make available to the affected stakeholders, verification that TPL Reliability Standards performance requirements will be met following the application of footnote ‘b’ (see Section II.6) and the assessment of potential overlapping uses of footnote ‘b’ with adjacent planners” (see Section II.8), it is hard to imagine what type of review and verification is required to show that “there are no Adverse Reliability Impacts including any potential cumulative effect within the Regional Entity’s footprint”.

The application of footnote 12 in TPL-001-3, Table 1 is inconsistent for EHV where it is applied for single contingency events in Category P1, but not for fault events in Category P2. Under Category P2 Single Contingency Event 3 Internal Breaker Fault no Non-Consequential Load Loss is allowed for EHV, that is to say footnote 12 is conspicuously absent. Every Event in Category P1 Single Contingency must be cleared with a breaker, and every breaker must meet the Internal Breaker Fault requirement of Category P2 Single Contingency Event 3. Because the performance requirements of the P2 Internal Breaker Fault must be met for EHV without the benefit of footnote 12, the appearance of footnote 12 for EHV is inconsistent with P1. The footnote 12 should be added to Category P2 Single Contingency Event 3 Internal Breaker Fault for EHV in the Non-Consequential Load Loss column. Also, a similar difficulty exists for Category P2 Single Contingency Event 2 Bus Section Fault where no Non-Consequential Load Loss is allowed for EHV. Where bus sections connect an element (Generator, Line, Transformer, Shunt Device) to one or two breakers the bus section fault will remove the element from service. Every EHV Event that includes footnote 12 in Category P1 Single Contingency that are connected by a bus section to breakers must also meet the requirements of Category P2 Single Contingency Event 2 Bus Section Fault which does not include footnote 12. Therefore the omission of

footnote 12 in the breaker internal fault event is "inconsistent with" the P1 event and we suggest adding footnote 12 to the P2 Event 2 The footnote 12 should be added to Category P2 Single Contingency Event 2 Bus Section Fault for EHV in the Non-Consequential Load Loss column. The new definition of Non-consequential Load Loss compared to the last version seems to have deleted the reference to Loads that may be lost during transient conditions due to under-frequency load shedding (UFLS), while the reference to Load Loss due to under-voltage load shedding (UVLS) is retained. As a result Load Loss due to UFLS would be part of Non-consequential Load Loss, and will not be allowed under single contingency. Because UFLS may also be triggered during transient simulations, please change the definition for Non-consequential Load Loss to read: "Non-Consequential Load Loss: Non-Interruptible Load loss that does not include: (1) Consequential Load Loss, (2) the response of voltage sensitive Load or frequency sensitive Load, or (3) Load that is disconnected from the System by end-user equipment." It is also understood that load loss due to UVLS or UFLS or load that are disconnected from the system by customer equipment are not to be used in meeting steady state reliability requirements. Therefore, in Table 1, please change header-note "i" to read: "The response of voltage sensitive Load and Frequency sensitive Load that is disconnected from the System by end-user equipment associated with an event shall not be used to meet steady state performance requirements."