Name (17 Responses)
Organization (17 Responses)
Group Name (7 Responses)
Lead Contact (7 Responses)
Question 1 (0 Responses)
Question 1 Comments (24 Responses)
Question 2 (0 Responses)
Question 2 Comments (24 Responses)
Question 3 (0 Responses)
Question 3 Comments (24 Responses)
Question 4 (0 Responses)
Question 4 Comments (24 Responses)

Group
Northeast Power Coordinating Council
Guy Zito
Revise the language in Section 3 under Survey—Method page 8 to read: • Simulations will be based on a case representing the expected 2015 system with stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. As an alternative, the Transmission Planner may assume uncleared faults or assume fault clearing at 5 seconds after fault initiation. The language changes in the first bullet are to provide a uniform year as the basis for all assessments. As presently written, the cases could be for the year 2022, where corrective action plans have been developed, but there is not enough detail known about their future installation yet to be able to complete the survey. Using the year 2015, or something akin to it, would allow for projects which are in process and are well known to be evaluated. The changes to the second item are to eliminate the need for contacting entities for estimated clearing times, since an uncleared or 5 second fault is sufficient since this is only a screening evaluation. Step 7 of the process will allow further refining based on actual anticipated clearing times. Revising the bulleted step eliminates a data request and it has no consequence on the usefulness of the final data to be provided. It would be beneficial if the final 'Request for Data or Information' provided additional guidance regarding which case(s) to use for testing, in order to achieve more consistent results without tying the hands of the entities performing the tests. Consider augmenting the text regarding case(s) to use in Step 3 with that the case(s) should represent system conditions for a study year within five (5) years, in an effort to simplify how to consider projects in progress or planned. By restricting the time horizon to five years, we believe that there is more certainty and information available regarding in progress or planned (not-yet-in-service) projects to perform the evaluation in a consistent manner.
There may be an error in the text associated with Note #2 in the Excel spreadsheets for 'Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems'. The present version of the text states: "The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.", while the text in row 2 of the Table states: "Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:". The text "meets all" in the notes should be replaced by "does not meet all" to be consistent with the text in the Tables.
No comments.
Bus needs to be defined in order to develop uniform assessments. Suggest a definition be developed similar to the following definition taken from NPCC's Criteria A-10, Classification of Bulk Power System Elements: "Bus …the term bus refers to a junction with sensing or protection equipment within a substation or switching station at which the terminals of two or more elements are connected, regardless of whether circuit breakers are provided. In this context, bus may not have a direct correlation to the use of this term in substation design or a power flow data set…" Specifics regarding bus configurations and other information can be found in the NPCC A-10 Classification of Bulk Power

System Elements document.
Individual
Shirin Friedlander
Los Angeles Department of Power and Power
we would like the schedule to be extended to 48 months because the estimate of engineer hours is too low, and engineering resources are already committed to meet other planning and regulatory burdens. LADWP's initial assessment indicates that a significant number of busses may remain on the "List of Busses to be Evaluated", so the burden on engineer hours may be substantially underestimated in the Draft Request for Data or Information. While LADWP does study Category D contingencies, such contingencies are selected by engineering judgment rather than by an evaluation of all possible Category D contingencies. (The number of permutations for Category D is very large.) Because of this, LADWP does not have a significant set of pre-existing Category D studies that can be used for this data request.
Individual
Thad Ness
American Electric Power
Table A: We suggest changing the criteria in row 3 from "Buses operated at 100 kV to 200 kV with 6 or more circuits" to "Buses operated at 100 kV to 200 kV with 6 or more circuits, except buses that are a breaker and half, ring bus, or double breaker double bus configuration, and buses with generation resources with gross nameplate rating less than 20 MVA." Compound bus station configurations are inherently more reliable than a single bus station configuration. The proposed three-phase fault test on these compound bus stations provides much less value to the process, because of the lower probability of a total protection failure relative to single bus configurations. AEP urges NERC to consider these revised screening criteria given that the volume of effort to reply to this data request is already quite heavy. Table C: We suggest testing a statistically significant sample to evaluate the Performance Measures in this table rather than using the entire list generated in Steps 1 through 3.
The scheduled reporting timelines are broken out by bus voltages ranges; however, it is not apparent where sub - 100 kV buses fit in the reporting timeline. The same applies to the data reporting spreadsheet. Based on the criteria set forth in the last two rows of Table A, some sub-100 kV buses could be in scope.
Though this most recent draft RFI apparently aims to lessen or limit the burden on registered entities, AEP still expects the request to be, as previously stated by NERC, "extremely burdensome". The burden that this data request places upon Planner and Owner resources is very substantial, and the manpower required to fulfill this request, just for AEP alone, is estimated to be approximately 7,000 hours. The burden of this data request will divert resources from performing their core responsibilities which have a much greater impact on the reliability of the BES. The execution of the survey process will require time consuming communications between business units (beyond what already takes place) within single companies and in many cases between multiple business units in multiple companies. In its current form, the method requires six handoffs between the TP and the TO or GO to complete the survey and a seventh handoff when the TP provides the results to NERC. It should also be noted that impending EPA regulations have driven potential retirement of units system-wide, and the changes coming in the next five years could be the largest that the system has seen. The results obtained by the proposed RFI could be quite different from those results obtained after those units would be retired.
Individual
Michael Jones
National Grid
We believe that it would be beneficial if the final 'Request for Data or Information' provided additional guidance regarding which case(s) to use for testing, in order to achieve more consistent result

without tying the hands of the entities performing the tests. We propose to consider augmenting the text regarding case(s) to use in Step 3 with that the case(s) should represent system conditions for a study year within five (5) years, in an effort to simplify how to consider projects in progress or planned. By restricting the time horizon to five years, we believe that there is more certainty and information available regarding in progress or planned (not-yet-in-service) projects to perform the evaluation in a consistent manner.
We believe that there may be an error in the text associated with Note #2 in the Excel spreadsheets for ‘Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems’. The present version of the text states: “The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.”, while the text in row 2 of the Table states: “Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:”. We think that the text “meets all” in the notes should be replaced by “does not meet all” to be consistent with the text in the Tables.
Group
SERC Planning Standards Subcommittee
Charles W. Long
The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... It should instead say "For each bus on the final list developed in step 9…" In the first paragraph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.
Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8. For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"
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
Michelle R D'Antuono
Occidental Energy Ventures Corp.
The process developed by the project team appears satisfactory to Occidental Energy Ventures Corp (OEVC). It steps through at least three analytical iterations – refining the list of affected busses and the associated Protection System components each time. That should ensure that only the most suspect relay systems are considered in a future mitigation process.
OEVC believes that the format and technical basis of the data reporting template are solid. We would

prefer that a single template be used wherever possible – perhaps allowing the Transmission Planner to add unique fields only if absolutely necessary. This will make the process more uniform across all of our generator Facilities.
We fully agree with the extension in time for lower voltage Facilities to 18 and 24 months. The initial focus should be on higher voltage BES components which have the most impact to reliability. Once those are addressed, the process should be more refined – which helps when dealing with a far larger number of impacted entities.
OEVC understands the background behind the data request, which is intended to address rare events which may lead to a wide-area impact. However, we are troubled that any number of worrisome scenarios can be envisioned – requiring the industry's immediate attention. Although OEVC saw data that showed that some outages were a result of lack of relay redundancy, we never saw data which showed that it was more critical than many other potential BES weaknesses. Should this set a precedent, the industry will be chasing every potential risk imaginable. These investigations have material impact on all of our resources, which then are not available for other more viable concerns. Furthermore, NERC is developing a data-driven method to determine the largest threats to BES reliability – which this exercise has bypassed. In our view, this is a far more scientific means to improve reliability; with years of proven results across a wide number of industries.
Individual
Don Schmit
NPPD
NPPD would like to see more clarification on when to include and not include breaker failure clearing times versus remote clearing times. There is discussion of how to calculate clearing times in the examples. One suggestion is to add a single Table or section in the document with how to assess clearing times. This might help guarantee that all entities evaluate local versus remote clearing time in the same manner. Could there be more clarification of the "battery open condition". Is it correct that a primary and secondary DC breaker is considered redundant from a single battery bank/charger? Cap banks are referenced in page 36 under shunt devices. If a cap bank scheme has a relay that detects single line to ground and phase faults, another relay that detects unbalance within the cap bank, and each individual can is also fused for over currents would this meet the attributes in Table B?
Group
Bonneville Power Administration
Chris Higgins
BPA appreciates the opportunity to comment on Order 754 Request for Data or Information and has no comments or concerns at this time.
Group
Pepco Holdings Inc and Affiliates
David Thorne
Step 2: The last sentence in the second bulleted item in Step 2 should be re-worded to read as follows: "Each Transmission Planner will create an initial "List of Buses to be Evaluated" by removing these "excluded" busses from the "List of Buses to be Tested"". The existing language which uses the phrase "any buses identified in this step (step 2)" should be removed, since it could be construed as allowing removal of buses solely on the criteria that transformer through fault protection exists, as that identification is also part of step 2. Alternatively, the bullets could be broken into steps 2A and 2B, or the identification of transformers with through fault protection be made into a separate step altogether. Step 7: The last sentence of footnote 13 should be re-worded as follows: "The operation of load shedding or Special Protection Systems may be modeled if the scheme is normally in service, capable of responding to the simulated contingency, and does not share a single point of failure with

any of the protection schemes being evaluated." Even if these schemes were not installed specifically to address the contingency being evaluated, ignoring the operation of these types of schemes during the simulation may provide an unrealistic representation of true system performance during the event. Step 8: The phrase "in accordance with the method described in step 4" should be re-worded to read "in accordance with the method described in step 3".
1)In the "Busses Evaluated by the Transmission Planner" tab, we believe that Note 3 should reference Step 8 rather than Step 7. Also, Note 4 should reference Step 9 rather than Step 8. In all the protection system evaluation tabs (Transmission Line, Transmission Transformer, Generator Step-up Transformer, Step-Down Transformer, Shunt Device, and Bus) the wording of 2)Note 2 conflicts with the wording in row 2. Note 2 should use the phrase "does not meet all the specified protection system attributes", in place of the current wording that reads "meets all the specified protection system attributes". 3)In the Station DC Supply Attributes tab an additional note should be added for clarity that states: "The total number of busses reported on this form should equal the total number of busses that meet the criteria in Table A "Criteria for Busses to be Evaluated". 4)Also see comments from question 4 below concerning posing additional questions regarding the use of independent DC distribution panels with single DC supply systems.
Although we believe the Drafting Team's time estimate for GO's, TO's, and DP's to complete Steps 5, 7, and 10 is about half of what would actually be required, we nevertheless believe that the 24 month schedule to complete this data request is adequate.
1) Table B: Having a single battery system is not one of the single point of failure attributes in Table B. However, suppose you have a single battery system that is connected to a single DC distribution panel with short un-fused leads and there is no incoming main breaker, or fuse, in the DC panel (Ref. IEEE 1375, Section 8.4, Fig 19). Per IEEE 1375 this arrangement is used "when interruption of the battery supply cannot be tolerated for any reason." Therefore one might choose this arrangement to enhance the reliability of a single battery system. There are, however, independent fuses in the DC panel feeding separate protection systems. Is having a single DC panel a violation of Table B? Or, by having independent fuses in the panel are the attributes of Table B satisfied? We believe the arrangement described above should satisfy the attributes of Table B. Therefore we believe Table B needs to be re-worded to address these types of DC designs and disagree with including the DC distribution panel itself under the DC Control Circuitry section of Table B. Obviously for two battery systems, independent DC distribution panels are common. However, for single battery systems they are not. The Drafting Team indicated that a failure of the DC supply in a single battery station would be excluded from the simulation testing protocol and instead elected to just gather statistics on monitoring of single DC supply stations. If you exclude the need to examine the failure of a single battery system from the testing protocol, yet the probability and consequence of failure of the battery is identical to the failure of the leads from the battery up to and including the main bus work in the DC distribution panel, then why shouldn't these facilities also be excluded from the testing protocol. If an entity employs a single battery directly connected to a single DC distribution panel (with no main breaker or other fuses in between), but utilizes independent fuses or breakers in the panel to supply independent protection schemes, then the single point of failure for the panel itself (i.e. main bus work within the panel) is no different from the failure of the single battery system, or the leads from the battery to the distribution panel. Also, since the battery charger (which by definition is part of the DC supply) is usually connected to the DC distribution panel, then the interconnecting wiring between the battery and the charger should be considered part of the DC system. In addition, the battery charger (which provides the DC supply monitoring) also monitors the health of the DC system up to and including the main bus in the DC panel. We do agree that on single DC supply stations that primary and backup protection should be supplied from separate fuses or breakers within the DC distribution panel. This would be similar in concept to having a single VT but requiring separately fused secondary windings. As such, the last sentence of Table B should be re-worded to eliminate the DC panel itself and read as follows: "For the purpose of this data request the DC control circuitry does not include the station DC supply, but does include all DC circuits used by the protection system to trip a breaker, including any fuses and breakers located in any DC distribution panels." If the Drafting Team is interested in knowing whether independent DC panels (with, or without, main breakers) are used for single battery systems then perhaps additional questions could be posed in the Station DC Supply Attributes data form. 2) Table C: The Order 754 Drafting Team in their response to Draft #1 comments agreed to relax the loss of generation criteria by "not including generators tripped as a direct result of remote fault clearing". As such, a note should be added to Item 1 in Table C that

reads: "(does not include the total loss of generation tripped as a direct result of result of remote fault clearing)". 3) We believe the Drafting Team's time estimate for GO's, TO's, and DP's to complete Steps 5, 7, and 10 is about half of what would actually be required. 4) The examples in the Appendix are quite helpful. The Bus and Distribution Transformer examples illustrate how to fill out the reporting template for the various single points of failure. It would have been equally instructive, if not more so, to show how the reporting template is to be filled out for the GSU and Transmission Line examples, as those schemes are more complicated. 5) Also, on the GSU example the switchyard (breakers and relays located within) are often owned by the TO. An overall unit differential relay (owned by the GO) often protects the GSU leads up to the switchyard breakers, whereas the TO may install distance or overcurrent protection as backup protection for this zone. The TO may own the breakers (including the CT's) but the GO may own the unit differential relay. These types of intertwined protection practices are common when the once vertically integrated utility companies (who owned both sets of protection) divested itself of generation assets. It would be helpful to identify how the reporting responsibility should be delegated for these types of arrangements when multiple parties own parts of the protection system for the same zone.
Individual
Patti Metro
NRECA
NRECA believes that the revised draft of the data request addresses many of the concerns presented by the industry to Draft 1 of the data request. The changes provide much needed clarity by providing examples and illustrations to help applicable entities complete the necessary steps outlined in the data request. Although there is a need to collect additional information from Transmission Planners as required in Order 754, NRECA believes the intent of the order was not to conduct new studies but to ask questions to determine current practices in conducting TPL standards assessments and any possible reliability gaps and the data request should be revised to reflect this intent.
NRECA thanks the team for extending the reporting schedule for the data request to 24 months. NRECA does question the need to staged reporting. The submission of data prior to the end of the 24 month period removes the flexibility for the Transmission Planner to complete these studies along with their normal TPL study cycle which will impose a substantial burden on the submitting entities by creating the need for additional studies.
NRECA still believes that the assessments conducted for compliance with TPL standards identifies any reliability issues that would result from protection system failures and as such are corrected as needed, therefore the data request as written is not necessary. If there is a need to expand the studies being conducted in the TPL standards, the vetting for such studies should be conducted through standards development not a data request.
Individual
Kirit Shah
Ameren
(1) Method Step 10 says to use the 'final List of Buses to be Evaluated' and Step 11, 3rd bullet then requests statistics concerning DC Supply attributes 'at selected buses.' Our understanding is that the Project Team is only interested in DC Supply attributes to be evaluated and reported for the final list of buses resulting from step 9. Please revise Step 10, 2nd bullet by replacing the following '…that meets the criteria in Table A …Evaluated' with 'resulting from step 9'. Step 10, 2nd bullet should then read 'The attributes of the station DC Supply listed in Table D, "Station DC Supply Attributes to be Reported," for each bus resulting from step 9.' (2) Method Step 3, 4th bullet: We request the Project Team to clarify: (a) Are we to leave a three-phase fault un-cleared for the entire simulation? (b) If this results in low-voltages in the area but not a Table C criteria violation, should it be reported? (3) We request the Project Team to identify steps 2 through 6 inclusive as optional, and at the end of step 7 append 'or from step 1 if steps 2-6 are skipped.' Then for clarification: (a) in step 8, replace 'as revised in step 6 in accordance with the method described in step 4, except that' with 'used in step 7 in accordance with the method described in step 3 using…' (b) and in step 9 replace 'was revised in step 6' with 'used in step 7'. (4) For those who will be following steps 2 through 6, the method is still confusing, because there is apparent redundancy between steps 2 and 6. It seems to us that the goal of steps 2 and 6 is the same (to pare down the list of buses that satisfy all the criteria of Table B, which is protection system redundancy). However, it is not clear to us how step 6 would reduce the

list of buses at all because the buses still on the list at step 6 which have already been evaluated against Table B and should have been removed from the list during step 2. (5) From our perspective, what is needed appears to be the following (please confirm): (a) The total number of buses which meet Table A. (b) The total number of those buses from 1- which do not meet Table B AND violate the parameters in Table C. (c) The DC Supply attributes per Table D for those buses from 2.
(1) We believe that the Note 4 in the Buses Evaluated by the Transmission Planner is incorrect. It should refer to step 9 result, not step 8, and should read '[This entry is equal to the number of buses on the final List of Buses to be Evaluated resulting from Step 9.](2) We suggest the Project Team, in each of the Attributes template tables, clarify that the Elements (e.g. Lines, Transformers, etc.) directly connected to buses resulting from step 9 are the only Elements for which Protection System is to be evaluated in detail. We suggest appending this to Note 1: 'The TO / GO / DP is only required to evaluate Elements directly connected to the final list of buses resulting from step 9.' (3) We suggest the Project Team to include an explanation that once any Protection System component (i.e., Protective Relay, or Communication System, or AC Current Input, etc.) is found non-redundant on an Element, the entity can record that and stop that Element's evaluation. We believe that this was covered in the webinar, but has been omitted from the RFI (or we could not find it.)
We appreciate the schedule revision, which will allow 24 months to complete the tasks, as compared to the previous 12 month schedule. However, it is questionable whether the intermediate status reports are really necessary. Can the intermediate reporting be eliminated or minimized?
(1) In the 'Distribution Transformer' example the use of the 50H wired as a partial differential is encouraged for redundancy; but, in general, we have seen this scheme being discouraged in relay literature because of a possibility of miss-operation due to poor CT performance. (2) We understand that the lack of redundancy for a distribution transformer low-side fault is outside this RFI scope. We request the Project Team to confirm this.
Individual
Mary Ann Zehr
Tri-State Generation and Transmission Association, Inc.
1.The first bullet in step 2 should either be moved to step 3 or removed entirely (our preference) since it is already a necessary part of the fourth bullet in step 3. 2.Clarify what "most conservative results" means in the first bullet of step 3. 3.Using "actual clearing time" from step 7 in step 3 instead of "maximum expected remote clearing time" would eliminate the need for steps 7 and 8. Without knowing the "actual clearing time," how does one know the maximum expected remote clearing time. However, rather than "actual clearing time," "expected clearing time" would be a better term to use. 4.What is the purpose of step 5, since this review should have already taken place in the second bullet of step 2? 5.Moving step 6 to after step 2 could greatly reduce the number of simulations required. 6.Eliminate steps 7 and 8.
There is a tremendous amount of data requested and it should not have to be entered through a portal, such as, this electronic comment form.
The reporting schedule is acceptable.
Group
FirstEnergy
Sam Ciccone
1. In Table B on Page 12, on the line item for DC Control Circuitry, DC control circuit requires two independent circuits where each DC circuit includes DC control circuitry, auxiliary relays, circuit breaker trip coils, DC distribution Panels, fuses and DC distribution Panel breakers. The description under this line item indicates that independent DC distribution panels are required for primary and backup relays – one DC panel for primary relaying a separate DC panel for backup. According to Table B, DC panels are considered an integral part of the DC control circuit to the relaying. This requirement seems to define a circuit to include the main DC panel and seems to conflict with branch circuit definitions in the NEC. We suggest the definition for DC Control Circuitry exclude the Main DC Panelboard. Instead, the Main DC Panelboard should be included in the DC station supply. This would require a modification of Note 1 under Table D on page 13. We suggest single point of failure redundancy would be met with a Main DC Panel with independent distribution panel breakers to feed primary, backup, and breaker failure relaying. 2. The last paragraph on page 32 regarding evaluating

the Bus Protection scheme in Figure 1-8 for single point of failure indicates the protection scheme that has a single point of failure as the lockout relay used to trip the Bus Bkrs and the auxiliary relay used to initiate breaker failure are supplied from the same DC. This discussion is confusing and needs clarification for this example. The scheme does not meet requirements for independent primary and backup relaying schemes and would appear to not meet single point of failure redundancy requirements for that reason. However, the discussion indicates “so a single trip coil should not be an issue” but yet Table B requires two independent DC control circuits with no common circuit breaker trip coils. Table B indicates separate trip coils are required. Another point of discussion in this example is breaker failure relaying. It is not clear in this data request to what extent breaker failure to trip relaying needs to be included in the data request review for single point of failure. This should be clarified in Table B. If breaker failure relaying needs to be included in the request to evaluate single point of failure (as discussed in this example) it should be included in the Protection System Attributes to be Evaluated as a separate line item in Table B. Also, it is not apparent that Breaker Failure to trip relaying needs to be on an independent DC circuit from primary and backup relaying and the breaker failure initiate contacts should be independent of the breaker tripping contacts. If a single relay contact is used to trip a breaker such as in an electromechanical relays, there appears to be no way to meet single point of failure redundancy requirements as an auxiliary relay used to initiate Breaker Failure to trip must be supplied from the same DC circuit as the tripping relay. 3. We believe that more detail is needed on the clearing times that need to be supplied in Step 7 shown on page 9 and the method to evaluate these times for various three phase bus faults. For example, Figure 1-12 on page 37 shows 2-115 kV busses with 15 breakers in a breaker and a half configuration. The discussion in the document is specifically for a fault between breakers 52-2 and 52-3 and identifying clearing times for this specific fault resulting from failure of one protection system. The document identifies breaker failure operating output in 10 cycles (with breaker times of 3 cycles) for a total of 13 cycles. The discussion seems to indicate breaker failure times should only be used if either breaker had only one trip coil. However, if there is fully redundant primary and backup relaying, for failure of primary relay, the backup relay would operate in 1 cycle (assuming Zone 1 relay operation) + breaker time = 4 cycles for local relay operation. The remote backup clearing from line A is identified as 20 cycles. Is the clearing time for this fault and Bus Section then 20 cycles for both the case of one or dual trip coils? The discussion should also indicate that all bus sections should be evaluated (all buses between all breakers as well as the main 115kV Bus 1 and Bus 2). More guidance is requested as far as what clearing times need to be reported for Bus 1 and Bus 2 in this example. It would also be beneficial to have an example for a straight bus. We assume in the straight bus case, if redundant dual bus protection was used, only bus protection clearing times would be reported. If only a single bus protection scheme was installed, the longest remote backup clearing time would be reported. Is that correct? 4. Footnote 13 on page 9 – The footnote indicates local relay protection operation times (specifically breaker failure relaying clear times) can be used in Step 7 only in the case of one breaker trip coil. This statement is confusing and seems to penalize entities that use dual trip coils and also have breaker failure relaying into supplying longer remote backup clearing times. Also, both redundant primary and backup relaying should be required as well as independent DC circuits to insure breaker failure is initiated. 5. Although the examples on pages 37 – 39 are beneficial, final clearing times that should be supplied to the Transmission Planner in Step 7 are not specified. Another example similar to Figure 1-13 but with independent primary and backup line relaying would be helpful. Clearing times supplied to the Transmission Planner in Step 7 should be identified in the example.
Individual
Martyn Turner
LCRA Transmission Services Corporation
• The second bullet of step 3 states, “Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time…” It is unclear how this would be applied to breaker-and-a-half or ring bus schemes and would appear to have the effect of tripping the entire station. We recommend the procedure state, “Trip the remote terminal(s) of all transmission lines connected to the faulted bus and expected to trip based on the maximum expected remote clearing time…” • Wind and solar units may be allowed to trip due to low voltages under the

ERCOT Voltage Ride Through (VRT) requirements (these units do not lose synchronism) because of the severity of a protection system failure contingency. Should VRT be monitored for Wind units in addition monitoring units that may trip due to loss of synchronism?
none
The time frame for completing this data request is appropriate.
The Transmission Planner is the only entity required to file results associated with this data request and other impacted entities are only required to provide information to the Transmission Planner. To ensure efficient and effective coordination of information between these entities, additional language needs to be included in the final attestation letter encouraging each entity required to participate as required. LCRA TSC suggests the following: Responding Entity is a NERC Registered: ___Transmission Owner ___Transmission Planner ___Generation Owner ___Distribution Provider Please mark all the following that are applicable: ___ Entity is a Transmission Planner and completed the data request as required by NERC. ___ Entity provided information to the Transmission Planner to complete the data request as required by NERC. ___ Entity provided information to another Transmission Planner and its response is being reported by this other Transmission Planner (List other Transmission Planner here:____)
Individual
Travis Metcalfe
Tacoma Power
In Note 1 for Table A, should a generator step-up transformer connecting aggregate generating resources, each with gross nameplate rating less than 20 MVA, but with total gross nameplate rating exceeding 20 MVA, be included for purposes of applying Table A? In Table B, for DC Control Circuitry, it is noted that DC control circuitry “does include…any DC distribution panels…” It is common that the station DC supply feeds one DC panel. Does this mean that DC control circuitry is automatically not independent, even if dual trip coils are used, different breakers within the DC panel are used, and there is no main breaker in the DC panel? If this is the case, there may be very few instances in which DC control circuitry can be considered independent. The burden estimates (engineer-hours) for Transmission Owners, Generator Owners, and Distribution Providers seems very low, perhaps off by a factor of 2 or 3, at least.
Individual
Milorad Papic
Idaho Power Company
The main objective of the 754 data request, as we understood, is to assess the impact of non-redundant protection systems on system reliability. Also, there is an expectation that collected data will help to identify if a gap exists regarding the study and resolution of a single point of failure on protection systems. The requested data will identify where delayed clearing due to protection failures could lead to a potential significant disturbance. Request for Data or Information (DRAFT 2) has incorporated a number of issues pointed out in comments December 22, 2011 to February 6, 2012 and addressed more clearly all steps for performing studies related to the Order No. 754 SPOF on protection systems. However, there are still some items in the Draft 2 that need clarification. We would like to point the following: Table A classifies buses into five different groups 100-200 kV, 200-300 kV, 300-400 kV, 400-600 kV and 600 + kV with applying two basic criteria for their classification based on the number of connected circuits. It would seem to IPC that might be a better metric to determine which buses to be tested (e.g. power entering and leaving the bus, fault current in p.u., etc.). It seems appropriate to test any 500+ kV bus regardless of the number of circuits. This present approved planning standards and proposed new planning standards deal with performance criteria of the BES under various n-0, n-1, n-1-1, n-2 and n-k category of outages which should also cover the conditions caused by protection systems failure events. IPC believes that studies conducted for compliance with TPL standards should identify any reliability issues that would result from protection system failures, therefore the data request is not needed. To pick number of busses for inclusion is likely to miss stations and buses that could have high impacts or include buses with little impact. Better to have a method evaluating all buses and excluding less critical buses, along the lines of PRC-

023. If there is a need to expand the studies being conducted in TPL standards the new standard development process should be used for this purpose instead of a data request. It would be beneficial if you provide more clarity in wording of a statement in the row 3 of Table D - Station DC Attributes to be reported? Also, more clarity is needed on what case scenario will be used to perform testing (load level, transfer level, generation pattern, etc.). Some entities might be required to use several stressing cases in order to evaluate properly SPOF across various parts of the system.
The template seems clear in what is being requested. Further comments will be unknown until the work is done completing the request. Additional direction, clarity, or examples for Table B would be helpful in the identification process for protection system single points of failure. Additionally, do the single points of failure determine the fault scenarios that must be simulated for delayed clearing or is there a different set of fault locations and scenarios that should be studied? This is not clear in the data request. The data request implies that bus faults should be run if a single point of failure is discovered and does not account for the actual bus topology (double breaker, ring bus, etc) that is used to limit the scope of protection system failures under fault scenarios.
As the reporting work includes groups other than just the Planners, a more granular schedule would assist in scheduling of the work for the non-Planning groups. For example, “Planners provide list of buses for Protection evaluation at the end of the 6th month for all 300kV and higher…”
The time estimates for collecting and evaluating protection systems are listed per bus, but using the criterion, a qualifying 230kV bus will have no less than 4 protection systems to be evaluated. It does not appear that this additional time requirement has been accounted for in the estimates, and represents a significant burden to system protection entities with a high number of qualifying busses.
Individual
Stephen J. Berger
PPL Generation, LLC on behalf of its Supply NERC Registered Entities
It appears the information request is overly broad since the problem (2011 SW Outage) was a single point open on a TRANSMISSION LINE not a single failure on a generator. That failure should have been studied by the TO/TP/PC. PPL does not feel that it is necessary to require generation data since a single outage on a plant is not likely to cause the transmission system to collapse. The work needed by GOs would typically require consultant work since normally the GO does not have on staff full time dedicated relay engineers. This would result in undue expense and would not have a significant reliability impact. PPL requests that GOs not become subject to TPL studies or the TPL standards.
N/A
N/A
N/A
Individual
John Pearson
ISO New England
Change language in Section 3 which is presently: • Simulations will be based on case(s) used to perform the most recent annual transmission assessment representing stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. Modify Language above to read: • Simulations will be based on a case representing the expected 2015 system with stressed system conditions (e.g., load level and transfer levels) that will likely produce the most conservative results based on past studies or engineering judgment. • Trip the remote terminal(s) of all transmission lines connected to the faulted bus based on the maximum expected remote clearing time provided by the Generator Owner, Transmission Owner, or Distribution Provider. As an alternative, the Transmission Planner may assume uncleared faults or assume fault clearing at 5 seconds after fault initiation. The language changes in the first bullet are to provide a uniform year for all assessments. As presently written, the cases could be for the year 2022, where corrective action plans have been developed, but there is not enough detail known about their future installation yet to be able to complete the survey. Using the year 2015, or something similar to it, would allow for projects which are in process and are well known to be evaluated. The changes to the second item are to eliminate the need for contacting entities for estimated clearing times, since an uncleared or 5 second fault is sufficient since this is

only a screening evaluation. Step 7 of the process will allow further refining based on actual anticipated clearing times. Revising the bulleted step eliminates a data request and it has no consequence on the usefulness of the final data to be provided.
It appears that there may be an error in the text associated with Note #2 in the Excel spreadsheets for 'Attributes of Evaluated Transmission Line/ Transmission Transformer / Generator Step-Up Transformer / Step-Down Transformer / Shunt Device / Bus Protection Systems'. The present version of the text states: "The number of Shunt Devices to be entered in Row 2 is the subset of [Device Type] entered in Row 1 for which the protection system meets all of the specified protection system attributes in Table B, "Protection System Attributes to be Evaluated.", while the text in row 2 of the Table states: "Number of [Device Type] for which protection systems does not meet all of the specified protection system attributes for redundancy in Table B:". It seems that the text "meets all" in the notes should be replaced by "does not meet all" to be consistent with the text in the Tables.
One of the attributes in Table B states "Communications Systems: The protection system for the element includes two independent communication channels and associated communication equipment……" Does this mean that for the communications system to be considered redundant, dual batteries are not required but instead only the DC circuitry needs to be separated such that no single DC fuse or circuit breaker would result in a failure of both communication systems? Bus needs to be defined in order to develop uniform assessments. Suggest the following for bus definition: Bus Within this document the term bus refers to a junction with sensing or protection equipment within a substation or switching station at which the terminals of two or more elements are connected, regardless of whether circuit breakers are provided. In this context, bus may not have a direct correlation to the use of this term in substation design or a power flow data set. In some configurations a bus may include more than one physical bus, such as in a breaker-and-a-half arrangement or a single-line-single-breaker arrangement in which two physical buses are connected through a bus-tie breaker. The examples in Figure 1 depict two of many possible configurations where two physical buses are tested as a single bus. Buses that are separated by normally open bus-tie breakers are considered as separate buses. The termination of line sections through switches should not be considered as a bus requiring testing unless the switches are activated as part of a protection system for the line which they sectionalize as part of normal protection system actions. Figure 1 – Configurations where Bus A and Bus B are tested as one bus. Please refer to NPCC A-10 Classification of Bulk Power System Elements In some configurations elements may not be terminated to the bus through circuit breakers, such as the generator bus for a unit connected generator or a bus between a transmission line and transformer that are switched as a single circuit. The examples in Figure 2 depict two of many configurations where two physical buses are tested as separate buses. Figure 2 – Configurations where Bus A and Bus B are tested as two separate buses. Please refer to NPCC A-10 Classification of Bulk Power System Elements
Individual
RoLynda Shumpert
South Carolina Electric and Gas
The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... I believe it should instead say "For each bus on the final list developed in step 9…" In the first paragraph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent

annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.
Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8. For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"
Individual
Nathan Smith
Southern California Edison
Southern California Edison has reviewed order 754 – Request for Data or Information ("The Order"). The Order appears to burden Transmission Providers with performing simulations on all the 100 and 200 KV substations, even if they are part of radial systems that are not today considered Bulk Electric System assets. This is a major impact to distribution system engineers. In addition The Order will require that the Transmission Provider gather loading information from Generator Owners and Load Serving Entities; their cooperation is not fully within the Transmission Provider's control. Generator Owners and Transmission providers will be required to perform test on a broad range of facilities; 1. Buses Evaluated. 2. Attributes of Protection Systems on Evaluated Transmission Lines. 3. Attributes of Protection Systems on Evaluated Transmission Transformers. 4. Attributes of Protection Systems on Evaluated Generator Step-up Transformers. 5. Attributes of Protection Systems on Evaluated Step-down transformers. 6. Attributes of Protection Systems on Evaluated Shunt Devices. 7. Attributes of Protection Systems on Evaluated Buses. 8. Station DC Supply Attributes. The hours involved to scope the test, evaluate the test results, and report back to NERC will be enormous. Furthermore the grounding test for these facilities have to be done while the equipment is energized, which is somewhat dangerous.
Individual
Maggy Powell
Exelon Corporation and its affiliates
The data request needs more detail concerning separately fused dc control circuits from a single battery and what constitutes independence of these circuits. The document should very clearly state that separately fused dc control circuits from a single battery are considered independent for the purposed of this survey.
The completion of data survey and submission to NERC is due within 24 months beginning the first day of the first month following NERC Board of Trustees approval. Exelon suggests that following NERC BOT approval the periodic reporting template be updated to specify reporting due dates to reduce confusion. In addition, although this data reporting schedule directly applies to Transmission Planners (TPs) and not to the Distribution Providers (DPs), Generator Owners (GOs) and Transmission Owners (TOs), there is a requirement for the DPs, GOs and TOs to provide certain data to the TPs. To ensure that the DPs, GOs and TOs are provided reasonable notice from the associated TPs on their expectations for data submissions, Exelon suggests that an enhancement be added to the End of the 1st month Activity section of the Schedule Reporting Table to include a requirement that the TP provide the associated DPs, GOs and TOs a plan of work with proposed milestone dates.
As a general comment, Exelon recognizes that this data will be requested of the Transmission Planners who in turn will gather the data from GOs, TOs and DPs. Because of this relationship, it is not easy to judge the scope of the data requested and the impact/burden of the task. The burden of the data requested will vary by entity (GO/TO/DP) based on a number of factors (e.g., the number of connected "elements" owned by a GO) and the extent to which entities are able to use existing studies and assessments. Exelon requests that throughout the data request process, care and consideration be given to requesting data with a justified value and to allowing for reasonable data

collection management including realistic turnaround times to avoid overburdening data providers. Thank you for the opportunity to comment.
Group
Southern Company
Antonio Grayson
The first bullet item in step 10 of the method says "For each bus evaluated in step 9"... It should instead say "For each bus on the final list developed in step 9..." In the first paragrph of the Rationale section at the top of page 14, there is the following statement: "Note that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes." This is confusing because buses which don't meet Table A are excluded from assessment and reporting. If this statement is referring to lines, transformers, etc. excluded by the notes on Table A, it should clearly indicate this. As currently worded the second paragraph in the Protection System Components and Attributes section undermines the validity of TPL-001-2 concerning the relay failures that are required to be studied. One NERC document should not undermine another Board approved NERC document. The following wording is suggested: "An alternative approach to limit the scope to the relay types listed in TPL-001-2 for contingency P5 (Table 1, footnote 13) was considered. For the purposes of this data request, however, it is not considered reasonable to rule out the potential for a failure of other protection system components. Requesting information regarding each protection system component will provide sufficient data to assess whether there is a further system protection issue that needs to be addressed and, if so, to provide information with sufficient detail to develop appropriate and focused measures to address the concern." Page 8, Step 3, 1st bullet: Cases used in the most recent annual assessment are not necessarily the most recent cases available. Flexibility should be given on which series of cases may be used. Also, to ensure consistency NERC should specify the case year to be used for the assessment.
Note 4 on the Buses Evaluated by the Transmission Planner table should refer to step 9 rather than step 8. For each of the tables regarding protection systems, row 2 conflicts with note 2. Row 2 says "does not meet" while note 2 says "meets all". Note 2 should say "does not meet"
Group
ACES Power Marketing Standards Collaborators
Jason Marshall
(1) We thank the drafting team for the additional clarity and clarification that other methods can be used to satisfy the data request. However, we continue to believe that the data request is broader than necessary. We believe that the data request should be limited to determining if Transmission Planners and Planning Coordinators have applied category C and D contingencies from TPL-003 and TPL-004 such that single points of failure in the Protection Systems are already evaluated extensively. This data request would be limited and could be completed in a relatively short period. Once such a limited data request is completed, then NERC can assess if additional studies are warranted. As the proposed data request stands now, Transmission Planners may be compelled to complete a burdensome and cumbersome request that could have been addressed more easily. (2) Despite the additional clarity provided in this second draft, the data request is still confusing and ambiguous and potentially contains duplicative steps. The second and fifth steps require the Generator Owner (GO), Transmission Owner (TO), and Distribution Provider (DP) to determine if any of the buses can be excluded because “the protection system(s) for all Elements connected to the bus and for the physical bus(es)” satisfy the attributes in Table B. The only difference appears to be that step 5 specifically states that GO, TO, and DP will review documentation while step 2 references the TO’s, GO’s, or DP’s knowledge of protection systems. We assume that step 2 is intended for the TO’s, GO’s, and DP’s personnel knowledgeable about their protection systems to perform a quick review without the aid of documentation to identify the buses with protection systems that meet Table B attributes. However, the step does not say this and only mentions the knowledge of the TO, GO and DP. One could argue documentation owned by the TO, GO and DP is part of their institutional knowledge and, thus, step 2 requires a documentation review. The bottom line is that further clarity is needed on what is specifically intended in step 2 and what is intended in step 5. Additionally, step 10 requires the GO, TO, and DP to conduct what appears to the same documentation review for protection systems

against the attributes in Table B. It is only after reviewing the explanation of step 10 in the example on page 20 that it becomes clear that the review is only to be completed if the documentation review in step 5 was terminated after finding the first single point of failure. However, step 5 never states the documentation review of protection systems for each element should be terminated after finding the first single point of failure. Rather, it states the review should be completed for all Elements connected to the bus. (3) Is the only difference in between the simulations in step 3 and 8, the clearing times? If so, why not utilize actual clearing times in step 3? (4) Step 3 could be interpreted as requiring simulations to be inconsistent with actual equipment that is isolated from clearing of a fault. For instance, the second bullet states that the remote terminal of all transmission lines connected to the faulted bus should be tripped. Given that the footnotes for step 1 state that all bus configurations will be treated as straight buses, step 3 could be interpreted as requiring all lines to be tripped for both physical busses of a breaker and half configuration. Rather, the more likely contingency for failure of a protection system on a breaker and half configuration is to isolate one physical bus which open ends lines connected to the cleared bus but leaves the lines on the other bus tied together. If the intent is to truly trip all lines connected to both physical buses as a screening study, then the step needs to state this more directly. Either way the step needs more clarity.
We thank the drafting team for extending the reporting schedule for the data request to 24 months. However, we do not believe it is necessary to report data for any buses prior to the end of the 24 month period. Submission of any data prior to the end of the 24 month period removes the flexibility for the Transmission Planner to complete these studies along with their normal TPL study cycle. Furthermore, it creates confusion regarding which case to use for the analysis and potentially creates the need to use inconsistent separate cases for the various buses. The first bullet under step 3 of the method states that simulations will be based on the case(s) from the most recent annual transmission assessment. Since the reporting period covers 24 months, there will actually be two annual assessments used. Thus, if a Transmission Planner has buses from 115 kV to 345 kV, they might start the data request using the cases from their 2012 annual transmission assessment for the 345 kV. By the time they start the analysis for the 115 kV buses, the 2013 annual transmission assessment will likely be completed. Should they then use the case(s) for the 2013 assessment which will provide the most up to date results or do they stick with the cases for the 2012 assessment for consistency.
(1) We continue to believe that this data request should be targeted at Planning Coordinators. For areas that operate in organized markets, Planning Coordinators are in a better position (number of staff, availability of data, already have stakeholder process for gathering data and information from TOs, GO, and DPs etc.) to handle this voluminous data request. For those areas that are not in an organized market, the Planning Coordinator and Transmission Planner are likely the same entity. (2) There is a statement on page 14 at the end of the first paragraph that needs further clarification. The statement reads: "that Elements excluded from the criteria in Table A for the purpose of identifying buses to be tested are not excluded from the assessment and reporting of protection system attributes". First, Elements are not excluded using Table A. Only buses are excluded. Second, the whole purpose of Table A is to limit the size and scope of the data request. If this statement is intended to remove some of the buses that are excluded, it needs to be stated more clearly. Furthermore, if this is the intent, we disagree with it.
Individual
Laurie Williams
Public Service Company of New Mexico
No comments.
No comments.
The current reporting schedule requires entities to report progress based on voltage class levels, that is, end of 12th month TPs are required to report data for buses operated at 300 kV, end of 18th month TPs are required to report data for buses operated at 200 kV or higher or below 300 kV, and end of 24th month TPs are required to report data for buses operated at 100 kV or higher or below 200 kV. PNMR recommends that reporting schedule be based on % of total number of buses to be evaluated by an entity. Thus, if an entity identifies 100 buses to be evaluated as part of the data request, reporting schedule may require entities to complete 25% of total numbers of buses by end of 12th month, 50% by end of 18th month, and 100% by end of 24th month. This will provide entities further flexibility.

1. PNMR requests further clarification on Actual Clearing Times. In absence of any definition of Actual Clearing Times, further guidance on what constitutes actual clearing times will be appreciated. 2. The DC control circuitry description below is too restrictive a description in some cases. Specifically, the words “no common circuit breaker trip coils” needs substantiation as to how that lessens reliability. We have cases where Protective Relay System # 1 trips both trip coils and likewise Protective Relay System #2 trips both trip coils. We also have lines with three protective relay systems with each system tripping both trip coils. We feel this is robust and reliable but the wording for DC Control Circuitry says otherwise. Please clarify.