**Individual or group. (56 Responses)**
**Name (33 Responses)**
**Organization (33 Responses)**
**Group Name (23 Responses)**
**Lead Contact (23 Responses)**
**Question 1 (0 Responses)**
**Question 1 Comments (56 Responses)**
**Question 2 (0 Responses)**
**Question 2 Comments (56 Responses)**
**Question 3 (0 Responses)**
**Question 3 Comments (56 Responses)**
**Question 4 (0 Responses)**
**Question 4 Comments (56 Responses)**

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| Group |
| Northeast Power Coordinating Council |
| Guy Zito |
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| Guidance for testing is not consistent and may produce less than meaningful results. There is a lack of necessary detail in the documentation. Clarifying information was provided during the webinar and needs to be included in the request. Other information is still unclear. Examples are: What system should be tested? Current or future system or some future system? Similarly, what year and load level should be considered? This is especially important when calculating consequential loss. If some TPs are basing their information off of an extreme weather forecast (sometimes referred to as a 90/10 forecast) and others are using a reference forecast (sometimes referred to as a 50/50 forecast), very different answers to similar situations could be reported. What system conditions should be tested – dispatch, transfers, etc.? We suggest something along the lines of the most stressful conditions as determined by the TP. Regarding Table A (page 8) of the Request for Data or Information, there is the likelihood that certain transmission lines above 100 KV may be identified that will not be owned by TOs or GOs. It is imperative to address how the collection of data from all entities will be accomplished. When counting circuits in Table A, more clarification should be provided on the handling of distribution transformers, GSUs and the impact of normally open circuit breakers or switches. On the teleconference it was stated that transformers with connections less than 115 kV should not be counted unless they were a GSU. It was also stated that when there is a normally open circuit breaker or any switching device, that configuration creates a separate bus. When determining remote clearing times, can credit be taken for failure of local blocking schemes, thus allowing high speed remote tripping? On the teleconference it was stated that transformers with connections less than 115 kV should not be counted as a circuit for purposes of Table A unless they were a GSU. It is unclear how to deal with transformers that serve load and also connect generation on the low voltage winding. Suggest that that these transformers not be considered GSUs unless the total generation is greater than 20 MVA nameplate. Also suggest that dedicated GSUs be ignored if the total generation is greater than 20 MVA nameplate. What is the process if the TP fails to complete the survey by the deadline? As stated in the Introduction and Survey Scope, at issue is “to first discover the extent and risk involved with single point of protection failure events.” The reliability risk with respect to this issue is sufficiently addressed in NPCC by the application of current NPCC Criteria, Standards, and Directories. Any power system element that can have a significant adverse impact on the bulk interconnected system is not vulnerable to a single point of protection failure for design criteria contingencies. The NPCC A-10 Criteria tests identify the Bulk Power System elements that are necessary for the reliable operation of the bulk interconnected system. This assessment (annually performed) gauges the impact on the bulk power system under the scenario of a total failure of the local protection at the station being tested. In effect, this process addresses the issue of adequate assessments for single point of protection failure that can have a significant adverse impact on the bulk interconnected system. NPCC Directory No. 4 requires that the “bulk power system shall be protected by two fully redundant protection groups, each of which is independently capable of |

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| performing the specified protective function for that element." Therefore any power system element that can have a significant adverse impact on the bulk interconnected system is not vulnerable to a single point of protection failure for design criteria contingencies. |
| Group |
| Bonneville Power Administration |
| Chris Higgins |
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| BPA is unsure of the purpose of periodic reporting to which steps are completed. BPA believes three milestones should be adequate: 1) Start of the data request period, 2) Acknowledgement of the request, and 3) The date the data request must be completed. |
| 1. BPA believes that more explanation and definition of the statistics needs to be provided. It appears the objective is to assess vulnerability to single points of failure of bus protection schemes that result in remote back-up clearing. If this is the objective, BPA believes further clarification may be needed. 2. BPA believes the methodology is unclear. If the objective is to arrive at a list of busses where there is a risk to BES reliability for a single point of failure of the protection system, BPA believes the steps would be: a. Gather the list of busses in question as described in Table A, b. Exclude a list of busses that meet the physical attributes for exclusion as described in Table B, c. From the reduced list, test the remaining busses based on either worst case (maximum clearing time) or actual data if available, as described in the methodology. For tested buses that did not meet criteria described in Table C, gather actual timing information if a worst case was used and retest those busses with the new information, d. Report results. 3. Comments on the methodology as listed: a. Steps in the list appear to divide responsibilities between owners and planners and create additional steps. BPA believes that this is confusing, making it difficult to determine what needs to be accomplished. BPA believes the Methodology should state who needs to coordinate in the description and the steps should state what needs to be accomplished. b. Step 1 is not clear. It is suggested to clarify as follows, "Each Transmission Planner will identify the following: i. A list of busses to be tested starting with busses identified from attributes in Table A, "Buses to be Tested", and, in cooperation with the Transmission Owners and Generator Owners, exclude buses identified from attributes in Table B, "Protection System Attributes to be Evaluated". ii. Transformers with through-fault protection and at least one winding connected at a bus to be tested as identified above." c. Step 2 as written suggests the test should be run on all buses identified from attributes in Table B. BPA suggests clarity should be given as follows, "Each Transmission Planner will simulate a three-phase fault on each bus in the list of buses to be tested developed from step 1. The three-phase fault is cleared based on the conservative simulation parameters..." d. BPA believes the first bullet in Step 2 should be clarified as follows, "Trip the remote terminals of all transmission lines connected to the faulted bus based on either the maximum expected clearing time or actual clearing time if available." It is suggested to make a similar clarification to the second bullet. e. BPA suggests combining items 3 through 6 into a single item 3, "For those buses tested that did not meet the performance measures in Table C, and were tested with a maximum expected clearing time, the Transmission Planner will collect actual clearing times from the Transmission Owners and Generator Owners and retest those buses." f. BPA believes that more definition and explanation of the statistics is needed. 4. Table A, "generator step-up transformers" listed in the note need to be clarified to be "generator step-up transformers with high side voltage of 100 kV or greater." 5. Table C, item 2 – BPA asks; what is the criteria to assess system separation resulting in islanding? Is this based on an unsolved power flow, engineering judgment, or some other criteria? |
| Individual |
| Joe O'Brien |
| NIPSCO |
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| There are some large TPs which have formed (for example PJM) while many small TPs still remain (for example within MISO). Are there any concerns with inconsistencies which may result with such diverse entities reporting the data. This appears to be quite an undertaking for the large TPs. Will |

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| there be a common model, such as a specific MMWG case, and tool which would be recommended for the analysis? |
| Group |
| Imperial Irrigation District (IID) |
| Jesus Sammy Alcaraz |
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| The schedule should be extended from 1 year to 2 years due to the estimated scope of work. |
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| Individual |
| Frank Gaffney |
| Florida Municipal Power Agency |
| In the Description section, first sentence, the term “elements” (which should have been capitalized since it specifically refers to the NERC Glossary term) should instead be the term “Facilities”. Throughout, the term “element” when used in this manner should be replaced with “Facility” since Elements include non-BES whereas Facilities are only BES. Note that there are instances of inconsistent use of the term “element” to mean protection system component. On the Method, step 1, there may be no need to “meet”, rather the need is to get the right data and information. On the Method, step 3, the test may not be appropriate for all exceptions to the Table B criteria. The test described is appropriate for battery / DC supply failure of a non-redundant battery system. It may be appropriate for non-redundant protective relay systems since those protective relays are what will likely trigger local stuck breaker protection. However, failure of a non-redundant communication system is usually different since a step-distance scheme will still act to trip the line before remote backup clears the bus. Even current differential schemes usually have zone distance as a back-up. The method for testing non-redundant communication systems ought to be different. Similarly, for CCVT / VT, some schemes use a current differential as primary and a step distance/ POTT/PUTT/Blocking as secondary. In this case, there is no need for redundant CCVT/VT since the current differential scheme has no need for voltage input and testing should be treated differently. And again, on non-redundant trip coils (e.g., quite often, there are redundant DC control circuits for primary and secondary relaying that hit the same breaker trip coil(s) and the tripping circuits are fused separately from the relay/tripping / lockout relay circuit), there will usually be a (separately fused) local stuck(or failed) breaker scheme that will operate faster than back-up clearing from remote terminals; and hence, for this case, the testing should be different. On the Method, steps 3 and 4, please be consistent and careful on terminology to avoid confusion. The use of the word “element” seems to imply a protection system element and not a BES Element. On the Method, steps 3 and 4 to identify single points of failure are confusing. How is it different than Step 1? And if it is different, shouldn’t it be part of step 1 to determine what should be tested? It seems that step 2 is set up to be a “screening” step. FMPA suggests making step 2 optional, in other words, if an entity wants to go right to actual clearing times and test that in step 6, that should be allowed without the need to perform step 2. For steps 2 and 6, although it is reasonable to assume that 3 phase faults are worst case, there may be exceptions. Typical phase protection is not susceptible to variation of clearing time with the level of fault current because typically they are step-distance or current differential schemes. However, typical older electro-mechanical step-distance phase protection schemes are accompanied by directional inverse time ground over-current schemes for single line to ground fault protection where clearing times are proportional to the available fault current. Hence, at light load levels, when there is less inertia on the system and the system is less stable in some regions, and the fault current available is less, the clearing times for remote clearing through inverse time ground overcurrent relays can be significantly longer than typical zone 3 phase distance clearing times; and hence, it is possible that some single line to ground faults may be worse than 3 phase faults if cleared remotely. Testing ought to consider this phenonema and if single line to ground faults are cleared significantly slower than 3 phase faults, then the single line to ground fault should also be tested. The survey is silent on the cases for which the testing is done. Testing should be done using the criteria of the TPL standards that imply a reasonable worst case analysis of dispatch and load level. Table A, the use of the word “circuits” is ambiguous. Is this intended to only include transmission lines in the count, or are transformers included. If only transmission lines, are radial lines included? If transformers are included in the count, are only GSUs and auto-transformers included, or are step-down transformers |

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| also included? FMPA suggests that radial lines and non-BES transformers should be excluded from the count and the term “circuits” as a results should be replaced with BES Lines and BES Transformers (we suggest not using the term “Facilities” as this would include in the count shunt capacitors, reactors, bus sections, and the like which will not influence the simulation). Table A, for Ultra-High Voltage, are we catching enough of the buses? It would seem to FMPA that any 500+ kV bus should be tested regardless of the number of circuits. Possibly a better metric to determine which buses to test would be available fault current expressed in per unit rather than number of circuits. Available fault current is a better indicator of voltage drop caused by the fault (i.e., high fault current means low system impedance which means larger voltage drop over a wider electrical area), which is a better indicator of the acceleration of generators during the fault, which in turn is a better indicator of transient stability. |
| “Buses Evalauted” sheet - “Buses” is ambiguous and should be defined as those buses with breakers (to exlude tap substations and the like) “Buses Evalauted” sheet – As discussed in question 1, step 2 should be optional; hence, the form on this sheet should be re-worked to identify that step 2 is optional and step 6 is the required step for testing. There are typos in the Notes to the different type of Elements tabs, e.g., note 1 for transformers, first sentence refers to transformers, second sentence refers to transmission lines. On the “buses” tab, we assume this means only bus sections that are not included in the zone of protection of protection systems for the Elements identified in the other tabs, e.g., a typical “North” bus of a breaker-and-a-half scheme. |
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| Individual |
| Patrick Farrell |
| Southern California Edison Company |
| This data request is overly broad and will require numerous time-intensive studies and potentially dangerous ground-faults tests that will not resolve the single point of failure (SPOF) concern raised by FERC. SCE supports EEI's comments on this data request. |
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| The scope of data requested is so great that we would recommend a minimum of 24 months for reporting the data. SCE supports EEI's comments on this data request. |
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| Group |
| PJM |
| Bill Harm |
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| The NERC Board of Trustees adopted the TPL-001-2 standard on August 4, 2011. The new planning standard was filed with FERC on October 19, 2011. This standard separates the performance criteria of BES elements based on their functionality. The designation of EHV and HV is used in the standard to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. This data request is a one-size-fits-all request and ignores the relative contribution of network facilities to the system reliability and ignores the different performance criteria. As a minimum the data request should be separated into distinct phases similar to the separation used in the TPL-001-2 standard. Separating the request into phases allows the person submitting the information to focus on specific areas as well as stratifying the information to aid NERC in compiling the results. The first phase of the request data should focus on system components operating at 300 kV and above (the backbone network). The first phase information could be complied while information regarding facilities operating between 200 and 300 kV is gathered and submitted. The third phase should be for information regarding facilities operating between 100 to 200 KV. |
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| Group |
| City of Tacoma, Department of Public Utilities, Light Division, dba Tacoma Power |
| Max Emrick |

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| 1. The wording in Step 2 of "Method" (p. 7, line 2) needs to be changed from "meet the attributes for all categories in Table B" to "does not meet the attributes for all categories in Table B". 2. The wording in Step 2 of "Method" (p. 7, line 18) needs to be changed from "exceeds at least one performance measure" to "meets at least one performance measure". 3. The wording in Step 7 of "Method" (p. 8, line 6) needs to be changed from "exceeds at least one performance measure" to "meets at least one performance measure". 4. The terms ‘expected remoting clearing time’ and ‘actual clearing times’ could be clarified (pp. 7-8). |
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| Regarding Schedule and Reporting on p. 12, we request twenty-four (24) months instead of twelve (12) months, due to the extensive and time-consuming nature of the data request. For example, the data request for identified buses over 200kV could be completed within twelve (12) months, and the data request for identified buses between 100kV and 200kV could be completed within twenty-four (24) months. |
| A suggested improvement to the Method would be more succinct verbiage, and possibly a logical flow chart or examples. |
| Individual |
| Zach Zornes |
| Chelan PUD |
| From the 754 data request, as I understand how non-redundant protection systems are treated in this assessment, if there is a single point of failure in the line protection system, the line is (assumed) to be cleared by the remote end. I did not see breaker failure protective systems addressed in this assessment. Could you please comment on whether breaker failure protective systems fit in (if at all) to this data request. If they have not been addressed, I would strongly recommend their effects be included as part of the data request. Also – the data request seemed to be more oriented toward line and transformer relaying. What are your thoughts on non-redundant bus differential schemes, or as in the above case, non-redundant breaker failure protection (example – breaker failure is integrated into the primary line relay, which was a single point of failure). |
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| Individual |
| Patti Metro |
| NRECA |
| From Order 754 and the subsequent meetings with FERC, NERC and industry subject matter experts, the goal of this data request should be to answer specific questions to determine if there is a reliability gap as described in the next steps in paragraphs 19-20 in Order 754 not place an undue burden on the industry to respond to the data request. Although the discussions on the two Order 754-Request for Data or Information Industry Webinars, indicated that the data request was not developed to place a burden on the industry to respond the draft data request as written does not reflect such discussions. Specifically, the data request on page 17 states “This data request will impose a substantial burden on the submitting entities”.It appears that the draft data request may require new studies to be conducted to provide responses to the data request instead of utilizing the existing studies considered as part of the TPL standards planning process which adequately address protection system failure. The draft data request should be revised to clearly reflect that the intent is to utilize existing studies and a limited amount of work is required of Transmission Planners, Transmission Operators, and Generator Operators to ensure that there is not a reliability gap associated with protection system failures. It is important that the term “Single Point of Failure” is understood by the entities responsible for responding to this data request in order for them to provide useful information. While it may be necessary to ultimately define the term utilizing the standard development process which allows for appropriate industry vetting, this current issue does not seem to allow for the time to utilize that process. Until such a time that this can be done, the data request should be revised to provide examples like those shared during the Order 754-Request for Data or Information Industry Webinars that answer specific questions such as: What should be counted as a circuit?; Would a cable tray containing wiring for redundant/multiple relay systems be considered a single point of failure or considered within the physical separation exemption?; Someone might say, a |

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| single point of failure could be a single control house in a switchyard. A bomb takes it out or a meteor falls from the sky and takes it out and there you have it, single point of failure for the loss of a control house. Is it really NERC’s intention that everything be duplicated? |
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| Depending on whether the draft data request is revised as suggested in the comments provided to question 1, system size and existing planning processes utilized to complete the TPL standards studies will determine the time required to respond to the data request. As written, an 18 months timeframe is a more reasonable reporting schedule than the 12 months provided in the draft data request. For many entities, these types of studies are conducted by consultants or utilize a regional planning organization which requires considerable coordination and time. |
| NRECA 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. 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. |
| Individual |
| Russ Schneider |
| Flathead Electric Cooperative, Inc. |
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| It is difficult to see how the folks using the results of the data request will be able to compile anyting more than braod statistics on how much work transmission planners report they had done numerically, if that is the goal, then it will be achieved, but it is hard to see what value that will produce. |
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| As a small entity we are concerned that this data request will create undue costs for our transmission planner upstream and that will take focus from their everyday activities. It is unclear the value of the results comapred to the compilation effort. |
| Individual |
| Maggy Powell |
| Constellation Energy on behalf of Baltimore Gas & Electric, Constellation Power Generation, Constellation Energy Commodities Group and Constellation Control and Dispatch |
| Survey – Method – Step 1 • Table A, Buses to be Tested, indicates buses operated at 200 kV or higher with 4 or more circuits; and buses operated at 100 kV to 200 kV with 6 or more circuits will be in scope for the survey. The document is not clear whether this refers to all circuits, or just networked circuits. Clarification was given in the Webinar that the intention was to include all circuits, but that is overly conservative. Please clearly justify the value of data to this level. While we recognize that any connected circuit represents exposure to a SPOF event, the consequence of tripping a radial circuit to the stability of the electric system is much less than for tripping a network circuit. If a 115 kV bus has 5 radial circuits and a single network circuit, regardless of the increased exposure, a SPOF event would still only trip a single network feeder. This data request stands to impose notable cost and burden on entities required to supply such data. A level of reasonableness is expected from NERC in defining the data request. Careful consideration must be given to the benefit gained by the data requested. The buses to be included in the survey should be determined by the number of connected networked feeders. There is other criteria in Table A that addresses the loss of load that would result from tripping radial circuits. Survey – Method – Step 3 • It is not clear whether the failure of a breaker trip coil, when there is local breaker failure protection, is considered a SPOF condition which must be evaluated. Breaker failure protection would trip all adjacent breakers directly and transfer trip only the remote terminals directly connected to the breaker in question. Local breaker failure should be used to exclude breaker related SPOF events from further evaluation. Please clarify. Survey – Method – Table B • Table B requires independent dc control circuits. This should very clearly state that separately fused dc control circuits from a single battery are considered independent for the purposes of this survey. |

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| The lack of definition of what constitutes single point of failure makes it unclear as to the degree of workload and project management associated with this data request, in particular given the varied ownership of related data. We request that NERC consider a tiered approach in data gathering in which planners can first identify the points of necessary data collection (buses) and then allow data providers to develop a responsible response plan. |
| Group |
| Southwest Power Pool Reliability Standard Development Team |
| Jonathan Hayes |
| We would like to be clear on who is the responsible party for submission of the data request. For example those under a RTO structure who are also registered as a transmission planner. In this case who is responsible for providing the data request both or just the RTO planning authority? While we realize it is the intent that the full redundant busses would be omitted from the analysis in step 3 the way step 2 is currently written it doesn't seem clear this is the intent. We would like for it to clearly state that fully redundant busses are excluded from this analysis. Step four needs a concise clear definition on what type of control circuitry you are looking for. We understand there is a document that references what the definition of redundancy is but would like for it to be understood in the methodology documentation. We would like clarification on the seasonal model to be used for this analysis. This didn't appear to be documented in this draft. |
| Under the first tab of the template we would like clarification on busses where there is no protection, for example taps on transmission lines. Under the Station DC Supply tab 4th item listed in the template there seems to be a typo and that a "not" and "monitoring of" needs to be included. "Number of buses for which the Station DC Supply includes one dc supply that is centrally monitored, but does not include monitoring of low voltage or battery open:" Also under the Station DC supply tab would it not be beneficial to instead of having the total number of busses which is already reflected in the busses evaluated tab to instead have the total number of busses with a DC supply attached? |
| We don't feel like 12 months is sufficient to complete the task at hand. The data gathering and coordination as well as the dynamic analysis will take some time. We feel like 24 months would be more appropriate to allow for this nine step process. Budgeting, manpower schedules, and external resources have already been approved for this year and adding this into the process is unrealistic. |
| Will this entire process be covered by the new TPL 001-02? If so then shouldn't we address this there? If not then shouldn't this be done under a SAR to revise the current TPL standards? |
| Individual |
| Terri Pyle |
| Oklahoma Gas and Electric |
| a. Please clarify the group responsible for submission of the data. For example, in an RTO structure Transmission Planning is conducted by more than one entity. In that case, who would be responsible for providing the data for this Data Request? b. While we understand that full redundant busses are omitted in Step 3, it is not clear in Step 2. Please revise to clearly state that fully redundant busses are excluded from this analysis. c. Please clarify the seasonal model to be used for this analysis. |
| a. "Station DC Supply" tab – Language correction suggestion "Number of buses for which the Station DC Supply includes one dc supply that is centrally monitored, but does not include monitoring of low voltage or battery open:" b. "Station DC Supply" tab – Should this tab include the total number of busses with a DC supply attached? |
| Twelve months is not a sufficient amount of time to complete the data gathering, coordination, and dynamic analysis required for this project. If thorough data is expected, 24 months would be a more realistic timeframe for obtaining the appropriate budgeting, manpower, and external resources necessary to complete this project. |
| Will this process be covered by the new TPL-001-2 standard? If so, then it should be addressed using this standard process. If not, a SAR is recommended to revise the current TPL standard. |
| Individual |
| Edward Davis |
| Entergy Services, Inc |

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| As noted in the 1/20/12 webinar, Step 1, first bullet item, please clarify that the intention is to develop a list of buses to be tested, and not a list of buses to be excluded. Step 1, second bullet item, revise to: “Also include transmission transformers with at least one winding connected and supplying fault current to a bus, and for which through fault protection is only provided via remote detection and clearing.” As noted in the 1/20/12 webinar, Step 2, please clarify the that simulations are to be performed for the list of buses indentified in Step 1, and includes buses which do NOT meet the attributes of Table B. For Table A, please designate the system planning model case(s) (e.g., summer peak, annual minimum) entities are expected to use for testing. For Table A, please add a statement that radial lines will be excluded. For Table A, please make it clear that only step up transformers associated with generators that meet registry criteria are applicable. Include a provision for entities to go directly to the actual clearing time methodology steps if they believe it to be more efficient. Finally, we suggest that the number of busses tested for steps 3 and beyond should not be more than 2% of an entity’s total number of busses greater than or equal to 100kv. If this cap is used then the most severe 2% of the busses tested in steps 1 and 2 should be chosen for steps 3 and beyond |
| For consistency, use the term “transmission transformer” as per Table A note instead of “step down transformer” in reporting data documentation, or define the term “step down transformer” in the RFI documentation. |
| The proposed schedule is vague. Since the RFI is an iterative process involving different entities, the schedule should establish appropriate timeframes for each of the applicable entities to complete their step/hand off activities. In addition, the completion of this survey and submission to NERC should be due within 24 months, not 12 months, due to the significant amount of information transfer required. |
| Remove RFI document hyperlinks to Protection System definition provided in the NERC Glossary of Terms since this definition is in the process of being changed. Make it clear that the existing definition of a Protection System, consistent with the System Protection and Control Task Force Technical Paper which is also referenced in the RFI document, is the definition to be used for this RFI effort. |
| Individual |
| Kasia Mihalchuk |
| Manitoba Hydro |
| 1.1 Manitoba Hydro believes that the “Method” of the data request needs to be re-evaluated as the proposed order of some of the steps could result in a significant amount of unnecessary work on the part of the Transmission Planner. The process would be more efficient and yield better results if the proposed Step 2 and Step 3 were reversed. It would make more sense for the Transmission Owner and Generator Owner to first determine whether a potential single point of failure exists at particular buses due to not meeting the attributes for any category in Table B. Following this the Transmission Planner will then simulate three-phase faults only at these potential buses; evaluate the results against the Performance Measures in Table C; and report accordingly. We propose that steps 2 and 3 be reversed. 1.2 In specifying the Protection System Attributes to be Evaluated in Table B of the Data Request, the NERC System Protection and Control Task Force (SPCTF) technical paper “Protection System Reliability – Redundancy of Protection System Elements” is referenced in a number of places. Has this technical paper received approvals from the NERC Planning and Operating Committees? If yes, please provide approval dates and a link to the approved version of the technical paper. If not, it is inappropriate to use an unapproved discussion paper as background to support certain aspects of this data request. 1.3 Table A : Buses to be Tested, of the Data Request specifies certain criteria to rule-in and rule-out buses at various voltage levels with specified numbers of circuits as well as generator buses higher than a specified MW level. It is not clear what is the basis of categorizing such buses as critical. What is the methodology used in identifying these critical buses? The methodology could be modified to be more consistent with the latest version of NERC Cyber Security standards CIP-002-5: Cyber Security – BES Cyber Asset and BES Cyber System Categorization, which is currently out for industry comment. This methodology would help limit the scope to a smaller set of facilities that has already been identified as potentially having Adverse Reliability Impact. 1.4 In “Protective Relays” attributes of table B, it states “The protection system for the element includes two independent protective relays”. What does “two independent protective relays” mean? Does it mean two completey independent protective relay systems, or some discrete relay devices (such as separate zone 1 and zone 2 relays) can be counted as indepenedent protective relays? 1.5 Footnote #8 is not good clarification for transformer through-fault. |
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| The requirement to complete the survey and all reporting within a 12-month period is extremely onerous. Adding a number of sub-period reporting requirements increases the strain on already limited resources. A significant amount of work is already required for the compilation of compliance evidence for self-certifications and audits, along with simulation and evaluation of power system equipment, redundancy and behavior to meet the requirements of existing and new reliability standards. In most cases all of the work pertaining to a particular area within the power system, for example protection, has to be addressed by the same staff with expertise in this area and familiarity with the system being studied, this can indirectly affect system reliability as scarce resources are diverted away from day-to-day operations. |
| In addition to the above, Manitoba Hydro has the following comments and questions: 4.1 In several parts of the Request for Data, such as in the “Introduction and Survey Scope” and “Authorithy” sections, the document refers to “Transmission Planner in the United States”; “User, owner or operator of the Bulk-Power System within the United States (other than Alaska and Hawaii)”; and “within the United States”. Please confirm that this data request does not apply to Canadian entities. 4.2 Under the title “Rationale” in paragraph 4 on page 11 of the Data Request, in explaining the reason for limiting the data request to three-phase faults, it is stated that “ …this method is appropriate in that single-line-to-ground (SLG) faults with delayed clearing typically evolve to a multi-phase fault…”. We disagree with this statement. Please show evidence that delayed SLG faults with delayed clearing will typically evolve into multi-phase faults? This is inconsistent with our experience. |
| Individual |
| Keira Kazmerski |
| Xcel Energy |
| A. The method does not recommend/specify the minimum duration for which the dynamic simulation must be run to evaluate the performance measures in Table C. Although it is understood that the simulation duration will need to be longer than the largest remote clearing time for elements connected to the faulted bus, it is unclear for how long must the simulation be continued after the bus fault has cleared. For instance, if the bus fault is cleared in 30 cycles, is it sufficient to continue the simulation for another 60, 120 or 300 cycles (1, 2 or 5 seconds)? Or is the simulation expected to last as long as 10 or 20 seconds? B.Should the minimum simulation duration be any different if one of the elements connected to the faulted bus is a transformer without through-fault protection? Since the method requires that such a transformer not be tripped, this will result in the bus fault never getting cleared for the duration of the simulation. C. Table C Performance Measures – While it is well understood how to monitor the amount of generation loss (measure #3) in a dynamic simulation, it is unclear how to detect the occurrence of system instability (measure #1) and/or system separation/islanding (measure #2) in a dynamic simulation. Tripping of several key transmission lines due to unstable power swings is a common mode of system instability leading to system separation. However, achieving this outcome in a dynamic simulation is contingent upon the availability of relay models within the stability cases. Simulating system separation will at a minimum require modeling out-of-step relays to detect which transmission lines would likely trip in response to a power swing produced by generator rotor angle oscillations. Since typical transient stability simulations are geared towards evaluating generating unit stability, the stability cases produced in any Region always include dynamic models for the generator machine and its associated controllers such as exciter, AVR, governor, PSS, etc. However, modeling relays within stability cases is not a common practice within all Regions, and certainly not in the Regions where we operate (MRO, WECC and SPP). Does the suggested methodology anticipate that each Transmission Planner will augment the stability case to include out-of-step relay models to be able to detect performance measure 1 (system instability) and performance measure 2 (system separation) in Table C during the dynamic simulation? Please clarify. |
| None |
| None |
| The data request does not suggest/specify which seasonal base case (peak/shoulder/light load) should be used for the dynamic simulations. Since the data request pertains to protection system attributes of existing facilities, we recommend specifying a 2012 peak load case. |
| Individual |
| John Bee |
| Exelon |
| The method presented requires assessment of a single point of failure of a number of protection |

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| system components. The driver for issuing this data request has been communicated as three main events (Westwing, Broad River and PacifiCorp 2008 Huntington event). All of these events were initiated by failures of auxiliary relays and included single-phase to ground faults that became three-phase or multi-phase faults. This event evidence points to a potential issue with single point of failure (SPOF) of auxiliary relays causing delayed clearing three-phase or multi-phase faults. The method presented goes beyond this issue and includes evaluation and reporting on SPOF for other protection system components that played no part in the events. Additionally, the recently proposed future TPL standard lists only relays and auxiliary relays for evaluation of SPOF. This proposed standard was vigorously discussed and vetted by NERC and the industry over a number of years. Evaluating for the loss of all the other single components will provide only a minimal amount of additional information regarding the issue of SPOF of protection systems. Even limiting the data request to SPOF of auxiliary relays during three-phase and multi-phase faults will result in a significant amount of work for the industry. The extra work required obtaining this additional detailed design data and performing additional studies will not provide significant additional insight into the SPOF issue to justify the effort but will consume significant time and personnel efforts from limited planning and protection engineering resources. These same resources are often involved in other NERC related efforts or projects to improve system reliability. Thus limiting the data request as discussed above balances the reliability issues to be looked at for a SPOF with the other reliability needs of the industry which are equally important and which will suffer by an expanded data request. Thus, the data request should be modified to target the source of the issue and evaluate system response for a three-phase fault with an auxiliary relay failure. It is also reasonable to evaluate for a three-phase fault with a relay failure if direct tripping relays are used since they provide the equivalent function of the auxiliary tripping relays. This more limited effort will still provide ample data to assess whether or not there is a SPOF reliability gap. |
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| Even by limiting the evaluation to auxiliary tripping relays and direct tripping relays functioning as auxiliary tripping relays, this data request will be a significant effort and will drain planning and protection resources. The reporting period is too short and there are too many reporting steps. The data request should be modified to allow one year to complete the evaluation for circuits 200kV and above and an additional two years to complete the evaluation for circuits 100-200kV. Reasons to extend the date for the 100kV to 200kV circuits include: o The 100kV to 200kV evaluations will likely be more complicated due to the more extensive use of backup protection to cover for SPOF of protection systems. o As stated in the data request, it is expected that disturbances on the lower voltage circuits will have less impact on the BES. o All of the NERC identified events were at voltage levels > 200kV. One report by the Transmission Planner should be sufficient to gauge the progress being made during each analysis period (one for >200kV and one for 100kV to 200kV) instead of a report at the 4th, 7th, and 10th month. It takes effort for the Transmission Planner to submit multiple reports and would seem to be a significant challenge for limited resources at NERC to process all these reports in such a short time period. |
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| Group |
| System Planning & Protection |
| John Merrell |
| The wording in Step 2 of "Method" (p. 7, line 2) needs to be changed from "meet the attributes for all categories in Table B" to "does not meet the attributes for all categories in Table B". The wording in Step 2 of "Method" (p. 7, line 18) needs to be changed from "exceeds at least one performance measure" to "meets at least one performance measure". The wording in Step 7 of "Method" (p. 8, line 6) needs to be changed from "exceeds at least one performance measure" to "meets at least one performance measure". |
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| Regarding Schedule and Reporting on p. 12, we request twenty-four (24) months instead of twelve (12) months, due to the extensive and time-consuming nature of the data request. |
| A suggested improvement to the Method would be more succinct verbage, and possibly a logical flow chart or examples. |
| Group |
| MRO NSRF |

| Will Smith |
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| • The NSRF is concerned that Single Point of Failure needs to be better defined. Without a clear definition, entities will likely interpret what is a Single Point of Failure differently which will could lead to incorrect data survey results and conclusions. • The NSRF is also concerned that the Table B criteria needs to be better defined. If a related white paper specifies if additional criteria such as dual DC power sources, dual DC fusing, complete and independent separate auxiliary relays, complete and separate lockout relays, such language should be included directly in the data request. • The NSRF suggests that the drafting team clearly exclude Table B criteria from being applied to remote terminals for clarity. • The NSRF is concerned that the proposed Survey Request goes beyond what is allowed by Section 1600 of the NERC ROP Section 1602.2.1. The proposed request is for more than just providing existing 'look up' data or information, it requires significant new studies to be performed. This is more than a data request. • NERC has not provided an estimate of the potential burden (costs and labor time) of the data collection as required by the ROP Section 1600(Ref. NERC ROP Section 1602.2.1(vi) There are extensive studies that would need to be completed as part of the request. • The NSRF is concerned the data request places what is in effect new performance criteria on the system beyond existing TPL requirements. If an entity shows an issue that is beyond existing NERC performance criteria, what are the expectations of the entity or the consequences to the entity? The data request refers to TPL-003-0, Table C of TPL-003-0, and TPL-001-2 P5 contingencies. It appears that the data request, items 6 and 7 exceeds TPL-003 criteria which shows a Single Line to Ground fault with delayed clearing or a 3-phase fault with normal clearing. The TPL-004-0 and Category D contingencies are performed and evaluated only. The NSRF suggests that NERC consider a simpler data request. Such a data request might ask if utilities have identified potential Single Points of Failure in their existing TPL studies under TPL-003 R1.3, R1.3.1, and R1.3.10. The NSRF has identified the following suggested procedural enhancements: Step 0 • The first step of the "Method" is missing. Step 1 should state that "Each Transmission Planner will apply the criteria in Table A to to create an initial list of "Buses to be Tested". This step has a crucial impact on how much work must be done for the next three steps. • The number and percentage of "Buses to be Tested" is expected to vary considerably among entities. In addition, based on preliminary review of our system, the proposed Table A criteria leads to the selection of a high number of buses that would require a very burdensome expenditure of resources and are unnecessary to develop the final list. • Based on a preliminary screening of buses in our system that would be on the initial list based on the proposed Table A, about 15% of the buses would be listed and subject to labor associated with the next three steps. Using the latest results for Category D8, Category D9, and other related analyses, only about 1.5% of the buses are expected to qualify for the final list (Step 7). All of the buses that are expected to make the final list would be on an initial list with the following Table A criteria: (1) buses operated at 200 kV or higher with 8 or more circuits, (2) buses operated at 100 kV or higher with 10 or more circuits, (3) buses operated at 100 kV or higher with 8 or more circuits which could result in 300 MW or more of consequential load loss, (4) buses with aggregate generation of 1,000 MW or higher, (buses directly supplying off-site power to a nuclear plant. The application of this criteria would only lead to the selection of about 5% of our system buses. Therefore, we recommend revising the Table A criteria to these values. • Provide more guidance/instructrions regarding the characteristics of qualifying circuits to assure that responding entities are consistent. o Consider whether circuits (even non-BES circuits) which network back to the BES should be counted o Consider whether circuits that lead to radial connected islands with significant generation should be counted. Step 2 • If the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive likely to be beyond scope of what should be appropriate for Section 1600 of the NERC ROP Section 1602.2.1. • Criteria 1 in Table C appears to only refer to angular system instability and the resulting trip of loss of more the 1,000 MW of generation. Voltage instability on the other hand could result in the loss of load, generation, or both. Criteria 1 does not provide guidance regarding what level(s) of angular instability, voltage instability, or both are appropriate to determine significant enough system instability. • Criteria 2 in Table C refers to formation of an island, but does not give consideration to whether resulting island would collapse or become stable. Step 4/5 • If the TO and GO identify multiple qualifying categories from Table B, then it is unclear which qualifying category should be the basis for the fault clearing scenario (with actual clearing times) that should be provided to the TP. We suggest that it be clarified that the TO and GO would provide only one fault clearing scenario to the TP and provide the fault clearing scenario that is expected be the worst case. Step 6 • As noted in Step 2, if the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested |

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| simulations is expected to be excessive likely to be beyond scope of what should be appropriate for Section 1600 of the NERC ROP Section 1602.2.1. Step 7 • As noted in Step 2, Criteria 1 in Table C appears to only refer to angular system instability and the resulting trip of loss of more the 1,000 MW of generation. Voltage instability on the other hand could result in the loss of load, generation, or both. Criteria 1 does not provide guidance regarding what level(s) of angular instability, voltage instability, or both are appropriate to determine significant enough system instability. As noted in Step 2, Criteria 2 in Table C refers to formation of an island, but does not give consideration to whether resulting island would collapse or become stable. |
| • The NSRF is concerned that the amount of burden imposed by the proposed request be restricted to that it is not excessive, unnecessary, or counter-productive. The NSRF would suggest that NERC ask entities about existing study work performed according to NERC category D contingencies considering the protection design criteria outlined in Table B. o The existing request seems to ask for 'exhaustive' data collection and study work by every entity for the defined set of buses to be tested, but a reasonable sample of data collection and study work might suffice to get a general idea of possible impact on an entities entire system. o System planners and system protection engineers will be diverted from work that is clearly required by Reliability Standards or benefit reliability to spend time responding to the survey request. • The circuit count should be based on the number of remote ends to open in order to clear the proposed bus faults? [The probability of 12 remote ends clearing successfully is much lower than only 4 remote ends clearing.] • The circuit count should include non-BES circuits whose remote ends have to clear to isolate the proposed bus faults? [Some non-BES transmission and distribution circuits lead to networks with generation or connection back to the BES which have to clear to isolate the proposed bus faults.] • The number of buses to be tested and the effort to fulfill the request for the identified buses may vary significantly among entities. Perhaps there should be a "cap" on the amount of work that is required by each entity to fulfill this request (e.g. all of the buses to be tested or the number of buses that would not consume more than 5% of existing staff resources). |
| o The NSRF is concerned that some entities might have so many "Buses to be Tested" that they cannot complete the work within 12 months and meet their mandatory requirements. The NSRF would suggest a 24 month time period at a minimum as an alternative. o The NSRF believes that many entities have to hire consultants to complete the amount of work for the request in the requested time frame. Are there enough consultants or resources available if many entities have to hire help? o If the more restrictive Table A criteria suggested in question 1 above is not accepted, then resource burden to perform the requested simulations is expected to be excessive and some entities might have so many "Buses to be Tested" that they cannot complete the work within 12 months and meet their mandatory requirements. o Perhaps the request should include a statement that entites may appeal to NERC to be granted exceptions that would allow it to meet the schedule or a schedule extention. o If the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive many entities might to hire consultants to complete the amount of work for the request in the requested time frame. Are there enough consultants or resources available if many entities have to hire help? |
| • The NSRF feels that the survey request needs to provide more explanation of what "single point of failure" means? Please define the term" single point of failure". • The method involves more than providing existing 'look up' data. It involves the performance of simulation work that could be significant burden to entitiy resources. The request for unbounded power system simulation work may be beyond the scope of what is allowed by Section 1600 of the NERC ROP Section 1602.2.1. • Perhaps it should be acknowledged that steady state analysis (which takes less time) may be used to establish that a bus meets one of Table C performance criteria, but dynamic analysis is required to establish that a bus does not meet any of the Table C performance criteria. |
| Group |
| SERC Planning Standards Subcommittee |
| Charles W. Long |
| We recommend that entities have the option of using actual clearing times instead of maximum clearing times in Step 2. The statement at the top of page 7 (Step 2, first paragraph) which reads "if any, meet the attributes for all categories in Table B" should instead state that "if any, [fail] to meet the attributes for all categories in Table B." The last bullet of Step 2 on page 7 should be changed to read "…simulated system response [equals or is worse than] at least one performance measure of Table C…" |

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| Item 4 on the Station DC Supply tab should be changed to read "...that is centrally monitored, but does [not] include low voltage or battery open..." On the Buses Evaluated tab the word "exceeds" in item 4 should be changed to "equal to or worse than." |
| Given that coordination will be required between GOs, TOs, and TPs which may involve different corporate entities, we believe that the schedule should be extended to 24 months. Three interim reports are excessive. Recommend that the 4th and 10th month reports be eliminated. |
| We feel that this request will be burdensome. To limit the burden on planning and protection engineers we suggest a limit on the number of buses to be studied to the most severe 2% of the total buses 100 kV or above for Steps 3 and beyond. A 2% limit would equate to roughly 580 buses in the Eastern Interconnection. |
| Individual |
| Robert Ganley |
| LIPA |
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| The reporting schedule appears to be very aggressive. This schedule will impose a significant burden on entities within NPCC, especially considering near term NPCC transitions to the revised NERC BES definition and associated compliance efforts / NERC registry transitions. Compliance with this order will require significant effort and will potentially overburden resources needed for near term NERC BES compliance efforts. Extending the data reporting completion date to be consistent with the NPCC NERC BES Transition Plan would facilitate reporting of data, given the expected near term NERC "TP" registry transitions. |
| 1) NPCC defines specific requirements applicable to design, operation, and protection of the bulk power system (BPS). NPCC presently utilizes a performance based test entitled "Document A-10 - Classification of Bulk Power System Elements". The object of this document is "to provide the methodology to identify the bulk power system elements, or parts thereof, of the interconnected NPCC Region". The A-10 performance based test is very similar to, if not more stringent, than the proposed data request. For example, the NPCC A-10 test is not restrictive to voltage class and also utilizes a steady state load flow test. Since NPCC members are required to perform the A-10 testing on a regular basis, it is requested that consideration be given to waiving this data request for NPCC. 2) This data request and associated reporting schedule will impose a significant burden on entities within NPCC, especially considering near term NPCC transitions to the revised NERC BES definition and associated compliance efforts / NERC registry transitions. Dedicated resources (planning and protection engineers) will be required to support this. Has a cost versus benefit analysis been undertaken to justify the expected burden? 3) What will ultimately be done with the data, and what is the expected outcome if a system wide reliability gap is identified? |
| Group |
| Arizona Public Service Company |
| Janet Smith |
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| There are many entities which are vertically integrated or have all the information they need to conduct the final studies. Hence an entity should have an option to bypass Steps 3 to 8 if it has all the needed information and wants to conduct the study in one step. It should also be exempt from reporting status if it has completed the study and submitted the results. |
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| Group |
| Pepco Holdings Inc and Affiliates |
| David Thorne |
| 1)In the "Method" on page 6, Step 1 excludes busses to be tested if the protection system meets the attributes in Table B. However the wording in Step 2 requires the Transmission Planner to study those busses identified in Step 1 "based on the Owner confirming that the protective system meets the attributes in Table B." This appears to be contradictory. If you eliminate busses from testing in Step 1 based on no protection system single point of failure, why are they being tested in Step 2? The |

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| busses which were excluded in Step 1 should not be tested in Step 2. 2) As presently defined in the data request, protection schemes that trip breakers which only have a single trip coil would not meet the attributes of Table B. However, Item 6 in the data reporting template "Instructions for Reporting Data" states that Transmission Owners "will not report a single-point-of-failure if it does not prevent initiation of local back-up protection, including breaker failure protection". We agree with this decision. Following this same logic, the presence of a single trip coil should not be considered a single-point-of-failure attribute in Table B, providing the trip coil failure does not prevent initiation of local back-up protection, including breaker failure protection. Table B should be modified accordingly to reflect this concept. Furthermore, if the protection schemes connected to a bus meet all other aspects of Table B except redundant breaker trip coils, and the breaker is equipped with a dedicated breaker failure scheme as described above, then the facility should be excluded from the busses to be tested in Step 1. This is because the breaker failure scheme is specifically installed to address the operational failure of the breaker (which itself is a single point of failure). TPL-003 and TPL-004 standards clearly provide for studies related to breaker failure, thus the need to provide additional tests in this request for breakers with single trip coil failures amounts to duplicative studies. 3) It should be clearly stated that for the dynamic studies being conducted for this request, you do not have to consider the complete loss of the station battery, at a station with only one battery, as a single point of failure. 4) In the "Method" on page 6, Step 1, the term transformers with "through-fault protection" needs to be better defined with respect to how it is to be applied for the purpose of this study. Footnote 8 defines "through-fault" to include events such as a broken wire or an intermittent connection; implying an open phase detection scheme, or a ground overcurrent scheme, would qualify as "transformer through-fault protection". However, for the purpose of this study only three-phase faults are simulated. If that is the case, only phase overcurrent, or phase distance protection, would "qualify" as "through-fault protection" for the purpose of a three-phase fault study. 5) In the "Method" on page 7, Step 2, it states that each transformer connected to the faulted bus that is not protected by through-fault protection should not be tripped, as well as any element connected to the other terminals of the transformer. Leaving the fault current contributions through these transformers "uncleared" in the initial simulations seems overly conservative in many cases. Even if there is no dedicated "transformer through-fault protection", back-up protection (either local, or remote) on transformer connected elements could operate to clear the fault, assuming they have been set with adequate sensitivity. Although this is not strictly "transformer through-fault protection", it serves the same purpose to eventually clear the fault. 6) For the studies defined in the "Method" (which are faults on the bus, or immediately onto a circuit connected to the bus) there is no need to address non-redundant communication system failures, providing at least one protective scheme also contains a non-pilot high speed phase tripping function (Zone 1, instantaneous overcurrent element, etc.), as the fault being simulated would not require communications to eliminate the circuit as a source to the fault under study. |
| 1) Item 6 in the data reporting template "Instructions for Reporting Data" states that Transmission Owners "will not report a single-point-of-failure if it does not prevent initiation of local back-up protection, including breaker failure protection". We agree with this decision. Following this same logic, the presence of a single trip coil should not be considered a single-point-of-failure attribute in Table B, providing the trip coil failure does not prevent initiation of local back-up protection, including breaker failure protection. Table B should be modified to reflect this concept. (see further discussion on this subject in the comments on Question #1) 2) The wording of the 3rd and 4th rows in the data reporting template for "Station DC Supply Attributes" is inconsistent with the wording in Table D of the request. As such, it is unclear what Attributes of Station DC Supply monitoring are to be surveyed. The two documents should be consistent. Table D appears to assess those stations where alarming for a battery open condition is centrally monitored. However, Row 4 of the data table appears to assess where either low battery voltage, or battery open, monitoring is employed. |
| The Data Request states that the request "will impose a substantial burden on the submitting entities." The Transmission Owner will need sufficient time, after the Transmission Planner completes the initial screening and identifies the list of facilities to be evaluated, to accumulate as-built protection data (survey of Table B characteristics, determination of actual clearing times, etc.) If completion of Step 2 takes too long, and depending on how may busses are identified, the 12 month interval may be too short to accumulate the necessary protection characteristics and complete the subsequent studies in Step 6. Additionally, some Transmission Planners are responsible for conducting studies on numerous Transmission and Generation Owners' systems, increasing considerably the number of studies that must be conducted by a single organization. As such, a full 24 months to |

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| complete the data request would seem more reasonable. |
| none |
| Individual |
| Kathleen Goodman |
| ISO New England Inc. |
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| There is a lack of necessary detail in the documentation at this point. Some of the information was provided during the webinar and needs to be included in the request. Other information is still unclear. Examples are: What system should be tested? Current system or some future system? Similarly, what year and load level should be considered? This is especially important when calculating consequential loss. If some TPs are basing their information off of an extreme weather forecast (sometimes referred to as a 90/10 forecast) and others are using a reference forecast (sometimes referred to as a 50/50 forecast), very different answers to similar situations could be reported. What system conditions should be tested – dispatch, transfers, etc.? We suggest something along the lines of the most stressful conditions as determined by the TP. When counting circuits in Table A, more clarification should be provided on the handling of distribution transformers, GSUs and the impact of normally open circuit breakers or switches. On the teleconference it was stated that transformers with connections less than 115 kV should not be counted unless they were a GSU. It was also stated that when there is a normally open circuit breaker (we suggest including a switch), that this then creates a separate bus. When determining remote clearing times, can credit be taken for failure of local blocking schemes and thus enabling high speed remote tripping? On the teleconference it was stated that transformers with connections less than 115 kV should not be counted as a circuit for purposes of Table A unless they were a GSU. It is unclear how to deal with transformers that serve load and also connect generation on the low voltage winding. We suggest that that these transformers not be considered GSUs unless the total generation is greater than 20 MVA nameplate. We also suggest that dedicated GSUs be ignored if the total generation is greater than 20 MVA nameplate. The data request should make clear that it applies only to BES facilities. Because NERC is considering this data request to aid whether future Standard modification is needed, and because NERC's jurisdiction to draft Standards is limited to BES facilities, the data requested must be so limited. |
| Individual |
| Patrick Brown |
| Essential Power, LLC |
| Essential Power, LLC ("EP") shares EEI's concern that NERC is using the Rules of Procedure to collect data without first justifying the industry costs and the reliability benefits of the data request. The data request only states that the request will impose a 'substantial burden' on the industry', without attempting to quantify that burden, or the potential reliability benefits. |
| No comment |
| The NERC Board of Trustees adopted the TPL-001-2 standard on August 4, 2011. The new planning standard was filed with FERC on October 19, 2011. This standard separates the performance criteria of BES elements based on their functionality. The designation of EHV and HV is used in the standard to distinguish between stated performance criteria allowances for interruption of Firm Transmission Service and Non-Consequential Load Loss. This data request is a one-size-fits-all request and ignores the relative contribution of network facilities to the system reliability and ignores the different performance criteria. As a minimum the data request should be separated into distinct phases similar to the separation used in the TPL-001-2 standard. Separating the request into phases allows the person submitting the information to focus on specific areas as well as stratifying the information to aid NERC in compiling the results. The first phase of the request data should focus on system components operating at 300 kV and above (the backbone network). The first phase information could be complied while information regarding facilities operating between 200 and 300 kV is gathered and submitted. The third phase should be for information regarding facilities operating between 100 to 200 KV. |
| EP agrees with the ISO/RTO Council's Standards Review Committee that NERC should capture the |

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| cost of the collection effort and show some tangible outcome (report or analysis) for the effort prior to issuing the data request. Resources will have to be reallocated in order for entities to respond, resources that could be better used on higher priority reliability needs. Refocusing these resources on this data request may not be the best use of those resources if the data is not utilized in a meaningful way or if there are other ways to make an assessment without an extensive data request. Estimating the cost of this data request helps preclude data requests for the same issue becoming useless annual exercises, particularly if nothing concrete is learned and shared from the first round of collection. For example, the industry has not seen any result or benefit from the generator recommendation data request, nor have we seen results from the IROL exceedence information request which was initiated based on a FERC comment that entities were going in and out of IROLs or waiting 29 minutes before correcting IROLs, yet this information is still being collected and reported on a regular basis with no defined purpose or reliability outcome, creating an expenditure of resources with no tangible improvement to reliability. |
| Individual |
| David Kiguel |
| Hydro One Networks Inc. |
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| As a non-US entity, thus not under FERC's jurisdiction, we would like to provide the following comment: The stated NERC objective for this Data Request is "to first discover the extent and risk involved with single point of protection failure events." Hydro One believes that the reliability risk with respect to this issue is sufficiently addressed in the Province of Ontario by application of current NPCC criteria and standards. The NPCC A-10 Criteria test identifies the Bulk Power System elements that are necessary for the reliable operation of the bulk interconnected system. This assessment is performed annually and looks at the impact on the bulk power system under the scenario of total failure of local protection at the station being tested. Effectively, this process addresses the issue of adequate assessments for single point of protection failure that can have a significant adverse impact on the bulk interconnected system. Furthermore, the NPCC Directory # 4 requires that "the bulk power system shall be protected by two fully redundant protection groups, each of which is independently capable of performing the specified protective function for that element." Therefore any power system element that can have a significant adverse impact on the bulk interconnected system is not vulnerable to a single point of protection failure for design criteria contingencies. |
| Individual |
| Blake Williams |
| CPS Energy |
| 1) The wording of Step 1 is very confusing. Please clean up the language to clearly state that a list of buses will be created based on Table A. This list can then be reduced if prior knowledge exists that a bus in the list has no single point of failure (as defined in Table B). 2) If actual clearing times are readily available for some or all buses identified in step 1, can steps 2 – 5 be skipped for those buses and go straight to step 6? 3) There seems to be confusion that "non-redundancy" equates to a "single point of failure". We contend that these do not always coincide. We believe single point of failure needs a clearer definition that is accepted industry-wide. An example of a protection system that we believe does not have a single point of failure, but is "non-redundant" as determined by Table B: A "pilot" relay used as primary protection (with a single communication channel) and an impedance relay used as backup protection (no communication channel), both fed by separate dc supplies and have separate trip coils and separate ac sources from a common VT. In addition, the "pilot" relay converts automatically to an impedance relay if loss of communication channel occurs. This system does not have redundant communication channels, but is covered by zones of protection, therefore a single point of failure does not exist, [unless the definition will require that tripping occur within a certain time frame (i.e. delayed clearing is not allowed)]. 4) Since the largest unit in ERCOT is greater than 1000MW, loss of 1000MW of generation under a SLG fault with normal clearing would be considered a NERC B. Why was 1000MW chosen as the minimum generation, when this is already considered as a NERC B? Is the intent of the language in Table C to say: 1) the loss of a TOTAL of 1000 MW of generation; or, 2) the loss of generators directly connected to the faulted bus followed by the loss of an additional 1000MW of generation? |

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| 1) Notes 3 through 6 on several of the reports state: 'the entries in Rows 3 (through 6) must be "less than or equal to" the entry in Row 2'. However, Row 2 is asking for those elements that meet ALL of the Table B requirements, while Rows 3-6 are only asking for elements that meet one specific part of Table B. So elements that have only partial redundancy will drive this number higher than that found in Row 2. The note should state that the number should be "greater than or equal to". 2) What is the value of including distribution transformer statistics in any of the reporting? |
| 1) Stand alone, 12 months for this request may be sufficient, if Transmission Owners didn't already have other data requests pending (e.g. The Line Ratings Request) and the "normal" burden of NERC compliance. We suggest an 18-24 month timeframe. |
| None |
| Group |
| Detroit Edison |
| David Szulczewski |
| Please change the wording in Step 2 to provide better clarity on how the resultant list from Step 1 is used. |
| The template instructions should be consistent with the data request document. For example, the template contains a section for Step down Transformers, but the data request document does not provide any discussion on how to incorporate this element. |
| The 12 month completion time may be too constrictive in that there may not be sufficient confidence in eliminating buses based on current knowledge in Step 1. A fairly comprehensive review may be necessary even in Step 1 to provide accurate data. |
| Please provide more detail on how Step down Transformers, with no secondary winding at 100kV or higher, such as distribution transformers and generating plant station service transformers, are considered in this analysis. Also, please provide a similar explanation for radial lines serving only load that are at voltages of 100 kV or higher. Please consider the following questions. Is there a generator MVA size threshold for including GSU transformers. If distribution transformers are included in this analysis, should Distribution Providers be included in the data request along with Generator Owners and Transmission Owners. |
| Individual |
| RoLynda Shumpert |
| South Carolina Electric and Gas |
| We recommend that entities have the option of using actual clearing times instead of maximum clearing times in Step 2. The statement at the top of page 7 (Step 2, first paragraph) which reads "…if any, meet the attributes for all categories in Table B" should instead state that "…if any, [fail] to meet the attributes for all categories in Table B." The last bullet of Step 2 on page 7 should be changed to read "…simulated system response [equals or is worse than] at least one performance measure of Table C…" |
| Item 4 on the Station DC Supply tab should be changed to read "…that is centrally monitored, but does [not] include low voltage or battery open…" On the Buses Evaluated tab the word "exceeds" in item 4 should be changed to "equal to or worse than." |
| Because coordination will be required between GOs, TOs, and TPs which may involve different corporate entities, we believe that the schedule should be extended to 24 months. Three interim reports are excessive. We recommend that the 4th and 10th month reports be eliminated. |
| This request will be burdensome. To limit the burden on planning and protection engineers we suggest a limit on the number of buses to be studied to the most severe 2% of the total buses 100 kV or above for Steps 3 and beyond. A 2% limit would result in approximately 600 buses in the Eastern Interconnection. |
| Group |
| Edison Electric Institute (EEI) and American Public Power Association (APPA) |
| Mark Gray |
| General Comments on the Method Although EEI/APPA supports this Data Request, we remain concerned that this effort is being launched without a common understanding of key terms which are fundamental to satisfying Commission concerns and directives in Order 754. Specifically, in this Order the Commission stated that it has a concern with the study of "the non-operation of non-redundant |

primary protection systems; e.g. the study of a single point of failure on protection systems" . Yet this draft Data Request makes no attempt to clearly and succinctly define protection system redundancy or single point of failure ("SPOF"). It is with this concern that we submit that the ultimate success of the data request may rest on the Industry's broad understanding of those terms. For this reason, we urge NERC to remedy this oversight prior to releasing the final version of the data request. We also support the intended purpose of the data request which we find in its "Method" seeks to limit the burden on entities while satisfying Commission concerns. However, we remain concerned that the effort will divert scarce manpower from other necessary tasks, complicating some entities' ability to perform other critical duties. One possible solution would be to allow entities to file for an extension of their data submittal on the grounds that the request is a hardship. Obviously, entities would need to adequately justify such a request in order to obtain the necessary approval. Specific Comments on Method Steps We recommend adding a new Step 1 (Suggested language): Each Transmission Planner shall apply the criteria in Table "A" to create an initial list of "Buses to be tested" in preparation for planning meetings with TOs and GOs. The following steps would then need to be renumbered accordingly. Step 1 –EEI/APPA acknowledges the need for meetings between TPs, TOs and GOs recognizing this as a necessary first step. However, we are concerned that this effort will be a very long and time consuming task which could take months for some very large TPs to complete. It is our recommendation that the Data Request make some accommodations to address this likely hardship. Bullet 1 – We recommend that the term "as built" be removed because it may imply to some entities that record drawings must be reviewed in this step. Step 2 – We believe this step incorrectly states that studies should be performed on protection systems which meet the attributes of Table B rather than what we believe should state "do not meet the attributes". We recommend re-titling Table B. (See comments for Table B below) Step 3 – The events that precipitated Commission concerns and have lead to Order 754 were in significant part due to the failure of auxiliary and lockout relays either through a failure of the devices or other deficiencies. For this reason we recommend the following language be considered: Transmission Owners and Generator Owners are to evaluate those schemes that do not fully conform to the attributes as defined in Table "B". This evaluation shall include an assessment of "as built" conditions in sufficient detail to ensures elements specified in Table "B" were not installed in a manner that would render the protection scheme or schemes inoperable should any single Table "B" device fail. The details of such evaluations are to be noted for submission to the Transmission Planner in line with the instructions provided in the data request template. Step 7 - This step states that the final list will include buses that exceed any of the three performance measures in Table C. The criteria for these measures are based on an event reporting system and not on any standards. If an island is formed of 1,000 MW or more, why is this equal in reporting priority to a system that does not maintain stability? It is quite possible that studies can prove that if generation equals load within the island, then it is a minimal reliability risk. Step 8 - More clarity should be provided in the statement which requires TOs and GOs to "provide 'as built" information'. The term "as built" in this context is vague and needs to be clarified if NERC wants consistency in industry reporting. We are concerned that more clarity needs to be provided so that entities have a clear picture as to the level and detail of entity assessments. It is our belief that without this level of instruction, the depth and breadth of entity assessments will substantially vary leading to both inconsistent data submissions which might render the work conducted in support of this data request meaningless or inconclusive. Step 9 – We recommend that TPs report the following: • Statistics concerning the buses evaluated • Number of identified elements considered for initial study • Number of identified elements retested due to concern over SPOF • Number of SPOF concerns identified Table A – EEI/APPA as a result of some suggestions by member companies offers the following modifications to Table A for consideration: Buses to be Studied • Buses operated at 200 kV or higher with 8 or more circuits • Buses operated at 100 kV or higher with 10 or more circuits • Buses operated at 100 kV or higher with 8 or more circuits which could result in 300 MW or more of consequential load loss • Buses with aggregate generation of 1,000 MW or higher • Buses directly supplying off-site power to a nuclear plant Guidance Instruction provided for Table A: The guidance/instructions lack sufficient detail to ensure consistent responses to the Data Request. Note the following suggestions: • Include more description, and perhaps examples, regarding the identification of circuits that should be counted. • Clarify whether circuits (even non-BES circuits) which have a connection back to the BES network should be counted • Clarify whether circuits that connect to radial islands with some percentage of generation should be counted • It is recommended that examples provided in the Webinar should be included in the Data Request or as an addendum to the Data Request. Table B – It is recommended that the table be re-titled as: "Protection System

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| Redundancy Criteria" with a note which states "For Study purposes only – NOT A NERC DEFINED TERM". We recommend the following changes be made to the language to Table "B". Protective Relays: The protection system for the element shall include two fully independent protective relay systems that measure electrical quantities, sense an abnormal condition such as a fault, and respond to the abnormal conditions in a manner that provides an equivalent level of protection should either system fail. Communications Systems: The protection system for the element shall include two fully independent communication channels and associated communication equipment whenever such communications between local and remote protective relays is needed to satisfy BES performance requirements as specified in the TPL standards. AC Current and Voltage Inputs: The protection system shall include two independent ac current sources and related inputs and two independent ac voltage sources and related inputs. Note: For purposes of this data request it is recognized that in many cases the two ac current sources may have a common primary current transformer (CT) winding and the two ac voltage inputs may have common capacitance coupled voltage transformer (CCVT), voltage transformer (VT), or similar device primary windings. Those sources with the identified commonality are not to be counted as SPOF for purposes of this Data Request. DC Control Circuitry: The protection system shall include two independent dc control circuits with no common dc control circuitry, auxiliary relays, or circuit breaker trip coils. Note: Entities are to assess how auxiliary relays are used and configured in order to determine whether the failure of one auxiliary relay might impact or exacerbate the intended operation of either independent protection system or possibly another dependent protection system such as was the case with the three events leading to this data request. In addition to the recommended edits provided above, we suggest language be added which would allow TPs to exclude some provisions of Table "B" assessment should they be determined as not relevant to the scheme being evaluated. We note that in Step 6 of the Reporting Template Instructions the following "For the purposes of this Data Request, Transmission Owners and Generator Owners will not report a single-point-of-failure if it does not prevent initiation of local backup protection, including breaker failure protection." We believe this to be an appropriate instruction and suggest that similar instructions be added to Table "B". We suggest the following or similar language: Protection schemes connected to a bus which meet all other aspects of Table B except redundant breaker trip coils, and the breaker is equipped with a dedicated breaker failure scheme as described above, then the facility should be excluded from the busses to be tested in Step 1. We believe this addition to be appropriate since the TPL-003 and TPL-004 standards clearly provide for studies related to breaker failure, thus the need to provide additional tests in this request for breakers with single trip coil failures amounts to duplicative studies. Table C – Note the following suggested changes to the Criteria provided: Criterion 1 appears is overly vague. EEI/APPA believes without greater specificity, respondents may not consistently conduct supporting stability studies in line with the intent of the Data Request. Criterion 2 refers to the formation of an island, but does not give consideration to whether resulting islands would collapse or become stable. Table D – EEI/APPA questions the necessity of reporting the level of detail as specified in the attributes of "Station DC Supply Attributes" since these systems were not contributory to any of the three events which initiated this data request. Alternatively, NERC may want to consider capturing the attributes of auxiliary and lockout relays since these devices, not DC systems, were significant contributors to the cascading outages initiating this data request. |
| We find the template to be appropriately aligned with the data request as presently written. Our only suggestion is that the template should be modified to allow for a comment field so that entities can appropriately preface the data provided, if necessary. |
| General Comments EEI/APPA is concerned that the proposed schedule is so vague that it is virtually meaningless. No attempt has been made to develop any type of meaningful schedule which might attempt to track TP progress or identify critical path items such as GOs and TOs who are not sufficiently engaged or responsive. Failure to Meet Reporting Requirements In order to adequately accomplish the intended objective, substantial coordination will be required between the Transmission Planners (TP) and the TOs & GOs. If any single TO or GO fails to meet TP needs their ability to fully comply with this mandatory data request will be impacted. We note that all three entities have obligations yet only the TPs are obligated to report their compliance and progress. In the event that TPs are unable to complete their assessments in line with the NERC schedule due to the unresponsiveness of a TO or GO, it is unreasonable to characterize the TP's data response as untimely The request should include provisions to allow entities to request that NERC provide exceptions or extensions if they can provide compelling reasons for being unable to meet the schedule. Effectiveness of the Schedule EEI/APPA questions what purpose the proposed schedule is intended to |

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| accomplish. We suggest that it would have been equally effective to simply provide the following milestones: 1. TP to report receipt of the Data Request 2. Electronic Data Reporting window opens on this date 3. Last day to file Data Request Results Very little in the schedule has any real meaning since the schedule doesn't attempt to identify any real milestone. As a result, TPs will have the burden of developing project schedules, allocating/balancing of scarce resources and internally tracking the entire process including TO and GO compliance and responsiveness. In the event TPs are unable to meet their schedule they will need some form of evidence to support they made every effort to comply. We also note that TPs will have the added burden of not only conducting the studies but managing the project. EEI/APPA questions, who will be responsible for resolving scheduling disputes? EEI/APPA suggests that NERC may need to consider tiered TP assessments focusing on those schemes which might have the greatest impact on reliability first. This approach was used for the Facilities Rating Alert which we believe has been a success. |
| General Concerns and Suggestions EEI/APPA suggests that NERC and its team of SMEs who are helping to draft this data request reconsider some aspects of the data request and pursue a more narrowly focused approach more in line with Commission concerns. We find the document in its present form to go well beyond both Commission directives and the perceived problem of SPOF. EEI/APPA supports both the Problem Statement and Consensus Points agreed to at the October 24-25, 2011 Technical Conference held at FERC Offices but we do not fully agree with the team's approach to solving those concerns. Nevertheless, we will support this effort but urge the team to consider a more narrowly focused solution better addressing Commission concerns. We also suggest that NERC add another "Next Step" to those steps identified at the Technical Conference which we believe should include the North American Transmission Forum. We believe this added additional step would allow entities to more openly share experiences with system protection related issues that have contributed to SPOF concerns. We believe this effort might ultimately prove to be the most effective method of answering and resolving Commission concerns. Procedural Concerns: Although EEI/APPA will not file a formal objection to this data request we remain concerned that NERC has not met all of the essential requirements of Section 1602.2.1 of the Rules of Procedure (ROP) necessary for a Section 1600 Data Request. Note our concerns identified below which identify the relevant parts of Section 1600 and why we feel those sections have not been adequately addressed. (i) a description of the data or information to be requested, how the data or information will be used, and how the availability of the data or information is necessary for NERC to meet its obligations under applicable laws and agreements; In the section entitled "Use of Data" NERC simply states that it was the objective of the data request to establish an "effective and efficient means to identify whether a reliability concern exists regarding single points of failure on protection systems". EEI/APPA submits that it is not enough to simply believe that you have developed an effective and efficient method, rather, the identified requirement obligates NERC to clearly state "how the data or information will be used" and "how the data or information is necessary". In the case of this data request, neither was answered. In fact, the data request as designed does not align with the requirements of the TPL standards which we fear may result in study results that either do not identify or clarify Commission concerns or possibly unintentionally mislead the Commission into thinking that a concern exists when in fact there is none. Furthermore, EEI/APPA remains skeptical that these exhaustive studies are even necessary. It is for this reason that Section 1600 requires a justification as to why the data requested is necessary so that over the 45 day comment period the Industry will be able to evaluate those justifications. Unfortunately, in the proposed data request, this essential element was not answered which may result in the Industry never having an opportunity to consider and evaluate the real need for the proposed data and associated studies. (vi) an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request. Relative to this second essential requirement, NERC has made absolutely no effort to estimate the burden to the Industry as required. In the section entitled "Burden to Entities", the draft data request simply states the "data request will impose a substantial burden on the submitting entities" as if this simple acknowledgement might somehow satisfy Section 1600. NERC must at a minimum estimate the financial and labor resource burden in real numbers, otherwise, this data request will be pushed forward without any real understanding by NERC as to how the Industry will be impacted in any tangible way. Furthermore, this lack of any real estimate negates any possibility for the Industry to provide meaningful feedback on the real financial and resource impacts to the Industry. Comments on the Rational EEI/APPA does not support the stated rational which has led to the overly expansive scope for this data request. In Order 754 the Commission identified a single reliability concern which questioned whether current TPL studies were sufficiently thorough to identify and assess the impacts of SPOF. In considering this |

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| concern Industry SMEs at the NERC Technical Conference in October 2011 clearly stated in the second Consensus Point the following: “Existing approved standards address requirements to assess single point of failure.” Given this consensus, EEI/APPA questions why elements far beyond those which have been proven to be vulnerable to SPOF problems are being assessed through these new studies when most agree the current studies are sufficient? We are also concerned that the collection of such a broad range of data may be intended for use and purpose beyond any effort to satisfy Commission concerns and directives specified to Order 754. We believe this concern is justified by the collection of system data in areas where no reliability concern has been identified. We are also concerned that elements that have been known to be significant contributors to SPOF concerns such as auxiliary and lockout relays are not specifically considered or included. For this reason, we strongly recommend that assessments conducted under this data request be limited to those elements specifically identified as having known SPOF risks while limiting the collection of data in-line with the existing TPL standard which we believe are sufficient to ensure an adequate level of reliability. Miscellaneous Other Comments Although we recognize the urgency of getting the draft Data Request finalized and approved, we are concerned that the Industry will not have an opportunity to provide additional comments on the final version of the Data Request. Given the fluidity of this draft document, we find it unfair to encumber the Industry with such an onerous effort without allowing an adequate comment period. We request that NERC post a revised version of the Data Request for a 20-day comment period prior to issuance of the final Data Request, to ensure that the issues raised above are fully clarified in advance. To do otherwise risks a myriad of on-the-fly, case-by-case clarifications that could compromise the effectiveness of the entire project. Issues Identified during the Webinars The question and answer sessions following the second Webinar indicated that the Table “B” set of protection system requirements may not be needed for a SPOF assessment. For example, a single trip coil that has failed may not in itself indicate a stressed system if the circuit breaker is protected with breaker failure relaying. We believe this to be correct and submit that a valid TPL standard would assess this condition. It has been noted that NERC stated in one of the Webinars that delayed clearing associated with three phase faults do not have performance requirements. We believe this to be inaccurate. TPL-004 requirement 4 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. Further, Table D states: Evaluation of these events may require joint studies with neighboring systems. |
| Individual |
| Don Schmit |
| Nebraska Public Power District |
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| 12 months is not an adequate timeframe for a detailed response. Need a minimum of 24 months to respond so as not to jeopardize the completion of required reliability based studies performed by planning staff. |
| 1.) This Request for Data is overly burdensome for the entities required to comply and publishing statistics on this issue provides no true improvement in reliability to the BES. 2.) There is no incremental value to the statistical data as this issue should already be accounted for in the entities' annual reliability assessment studies for Category D (TPL-004) events. 3.) If this data request is made to the registered entities, a.) Should be limited to > 200 kV only, nothing < 200 kV should be evaluated. b.) 12 months is not an adequate timeframe for a detailed response. Need a minimum of 24 months to respond so as not to jeopardize the completion of required reliability based studies performed by planning staff. This issue has already sat in NERC courts since 2004, so a 1-year response requirement is completely arbitrary and not justified based on the potential impacts to reliability of the BES. |
| Group |
| Western Area Power Administration |
| Brandy A. Dunn |
| The general approach (Steps 1-9) is good in that it produces a good sampling for determination of a potential risk. However, this data request as specified remains extremely burdensome. The scope of this initial assessment should be reduced significantly on the basis that the 'single point of failure' risk |

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| is quite unkown and that this data request is for the purpose of assessing if such risk is significant to the reliable operation of the BES (regarding non-redundant primary protection systems). Those results should then determine if further inquiry is warranted,or not, prior to being requested. We suggest the following revisions to Table A as a primary scope reduction until initial results warrant further inquiry: • Modify the first item of the Table A, “Busses operated at 200kV or higher....” from 4 to 6 circuits. • Eliminate the second item of Table A, “Busses operated at 100 kV to 200kV with 6 or more circuits.” The BES definition has yet to approve the 100 kV inclusion. • Retain the third item of the Table A, but be clear that this is 4 or more circuits AND 300 MW load loss. We believe this adequately addresses under 200 kV for this initial assessement. • Retain the fourth thru sixth items of Table A as is. Please clarify the following: Should the minimum simulation duration be any different if one of the elements connected to the faulted bus is a transformer without through-fault protection? Since the method required that such a transformer not be tripped, this will result in the bus fault never being cleared for the duration of the simulation. |
| The draft template appears to be generally appropriate. |
| Unless the scope of this request is reduced significantly, the 12 month schedule as proposed is unrealistic and/or will jeopardize appropriate action being taken for known reliability concerns by diverting critical planning and system protection resources away from reliable operation of the BES. |
| Following this and/or further ‘single point of failure’ assessment(s), and prior to further analysis and/or standards development, a comprehensive cost-benefit analysis should be utilized to justify the cost-benefit-ratio of perceived reliability need and/or improvement to the BES. These results should be presented to the rate base customer prior to adoption of any new standard or inclusion of existing standards. The base rate customer needs to be aware of ‘why’ and ‘how’ such inclusions provide increased reliability and at what cost. The customer is not adequately represented in the development of reliability standards which have direct and significant cost implications to the end user. There is no mechanism and/or transparency to vet consideration and development of reliability standards through the customer who will pay for the associated enhancements. Effectively this becomes taxation without representation. |
| Individual |
| Zachary Scott |
| Public Utility District No.1 of Snohomish County |
| Comment on page 6 in the Survey, under Method item 1, first bullet and footnote 7: What is the rational of analyzing ring bus and breaker-and-a-half configuration for single point of failure? The purpose of the ring bus and breaker-and-a-half is to reduce number of electrical device on a single bus. The protection system is set individually for each bus sections. |
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| Comment on page 7 in the Survey, under Method item 2, first bullet: Would like to clarify ‘terminals’ in this sentence. On tripping of remote terminal, depends on the type of bus configuration, you could be tripping one breaker or multiple breakers. We suggest to change ‘terminals’ to ‘terminal(s)’. Restate as follows: Trip the remote terminal(s) of each transmission line connected to the faulted bus based on the maximum expected remote clearing time provided by the Transmission Owner or Generator Owner. General Comment: As mentioned in the webinar, radial line is included in the bus termination count. Just for our information, could you clarify the definition of Radial line? Our understanding is a line is radial if only contain load and has one transmission source. So if a line has Normal Open switch or has a transfer scheme (break before make) and we considered it to operates as radial line, is this consider as a radial line? |
| Individual |
| Barry J Skoras |
| PPL Electric Utilities Corporation (PPL EU) |
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| PPL Electric Utilities Corporation believes that a breaker with a single trip coil would not be a single point of failure if independent breaker failure is employed for the breaker. |

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| Group |
| FirstEnergy |
| Sam Ciccone |
| 1. NERC may want to consider using the tools afforded by the Standards Development Process to analyze this subject. A field trial conducted by a small group of industry experts may be more efficient, less time consuming and may quickly determine if there are indeed any reliability issues with regard to single point of failure. The team could develop a SAR in parallel to the field trial and include in the scope of the SAR the need to clearly define single point of failure and explore possible needs for new requirements in the TPL standards. 2. If this data request moves forward, NERC may want to consider the following: During the Order 754 webinars, a question asked: "Is it necessary for the Transmission Planner to simulate tripping remote terminals of all lines, or can tripping be limited to only those lines associated with the breaker failure scheme operation?" We believe that breaker failure protection should be considered in the evaluation method and suggest it be added to step 5 or made a separate step and state: "When the only single point of failure of the Protection Systems for elements connected to a given bus are the breaker trip coils, the Transmission Owner and Generator Owner will provide the actual protection system operation or the actual tripping as performed by the breaker failure scheme." Then, in Step 6 or subsequent step, language should be added to specify that the "Transmission Planner can assess performance based on the actual protection system operation or the actual tripping as performed by the breaker failure scheme information provided in Step 5." |
| Data submittal excel document - On line 4 of the Attributes of Protection Systems which identify Transmission lines, Transmission Transformers, GSU Transformers, Step-Down Transformers, it should be realized that few of the relay communication systems (transfer trip or communication based schemes for fast tripping) are required to meet TPL standards. Therefore, the quantities supplied in this line item will only reflect a review of those elements where communication based tripping schemes are required to meet TPL standards. |
| There is some concern that the data collection and fault simulations will be burdensome to entities and divert strained resources away from compliance with existing standards. Therefore, our preference would be to separate the data collection into multiple phases and start with the highest risk system components. We suggest a tiered approach to first evaluate the 300kV and above systems, then secondly review the 200kV to 300kV systems followed by the remaining 100kV and higher systems. |
| 1. The wording proposed in Table B for AC current and voltage Inputs should be clarified. The description for independent AC current sources should identify separate primary and backup relaying on completely separate CT sources but instead indicates “except that two ac current sources may have a common primary current transformer (CT) winding…”. The primary winding of a CT is the primary conductor or bushing unless this is also intended to cover aux CTs. Is it the intent of this wording to imply single point of failure criteria are met if one set of relays are connected to the main CTs while the second set of relays can be connected to the secondary of an aux CT off the main CT? If so, we respectfully disagree as the intent of having separate independent relays on separate independent CTs is to mitigate a single point of failure for the AC current source. The wording in the document indicates otherwise and that it is adequate to have independent relaying on the same CT primary winding. Also, relaying on auxiliary CTs have primary and secondary windings but the wording in the document does not address auxiliary CTs. A similar comment applies for the independent ac voltages sources and the wording “except ……… the two ac voltage inputs may have common coupled voltage transformer (CCVT), voltage transformer (VT), or similar device primary windings”. We assume the intent of this statement is to indicate primary and backup relaying connected to different secondary windings of a CCVT or VT meets the criteria for two independent ac voltage sources. The wording should be revised to reflect this. Also, aux PTs are not addressed. 2. The requirement in Table B for Communication Systems between protective relays is needed to satisfy BES performance in the TPL standards should identify the specific TPL standards the document is referring. 3. The wording in Table B for DC Control Circuitry is not specific. Is a separate battery system, separate DC panels required for meeting the requirements for single point of failure for Table B? Table D seems to indicate this is required but Table D is not referenced in Table B. Or does one battery system with one DC panel and separate independent DC circuits (either fused or with circuit breakers) meet the DC control Circuitry requirements for single point of failure. 4. General Comment for Table B – the table does not provide enough detail and examples to determine whether a TO or |

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| GO meets single point of failure requirements or not. Perhaps an appendix with examples would be in order to clarify the intent. Without enough detail, assumptions have to be made. 5. The term “as built” information in Step 8 on page 8 of the Request for Data or Information [DRAFT] is not clear. |
| Individual |
| Saurabh Saksena |
| National Grid |
| This is much more than a simple request for readily available “system data”. This order directs that detailed system studies be performed to characterize the system transient performance. It then directs that a detailed engineering review be performed at various facilities. NERC specifically identifies that this data request “will impose a substantial burden on the submitting entities”. Since there is such a substantial burden, has NERC performed a cost to benefit analysis of what it hopes to gain from applying this method, and are there other methods that NERC considered that would be less of a burden, but would provide some indication of the exposure of the industry to the non-operation of a single protection system issue? One option might be to take this in stages. Such as perform a screen just on Table B and report that data, without performing any transient simulation studies. Depending on the numbers of buses compared to total, then make a determination if it is warranted to go further. If the percentage of buses is less than 20% in a region go no further. If it is greater consider doing further analysis as a separate data gathering analysis. |
| No comment. |
| The reporting schedule appears to be very aggressive. The proposed schedule will impose a significant effort for both transmission planning and protection engineers. These resources are assigned to dealing with NERC BES bright-line transition plans and these resources overlap with those needed for this data request. Compliance with this Request for Data will potentially overburden resources. Extending the data reporting completion date such that it does not overlap with the NERC BES Transition Plan would help the industry manage their limited resources. |
| 1) NPCC defines specific requirements applicable to design, operation, and protection of the Bulk Power System (BPS). NPCC presently utilizes a performance based test entitled “Document A-10 - Classification of Bulk Power System Elements”. The object of this document is “to provide the methodology to identify the bulk power system elements, or parts thereof, of the interconnected NPCC Region.” The NPCC A-10 performance based test is very similar to, if not more stringent, than the proposed data request. For example, the NPCC A-10 test is not restrictive to voltage class and also utilizes a steady-state test. If a bus is identified as being “bulk” per the NPCC A-10 test, then it is required to have dual protection systems. It is not clear that proposed analysis and studies related to this data request will result in any reliability benefits beyond what we already are achieving by performing the transient stability test for ‘Classification of Bulk Power System Elements’ in accordance with NPCC A-10. We would respectfully request NERC to consider leveraging our resources by providing a waiver to NPCC registered entities regarding this Request for Data based on systematically performed system evaluations for compliance with NPCC Document A-10. 2) This data request and associated reporting schedule will impose a significant burden on entities. We estimate our combined incremental work load related to this Request for Data to be about 12 person-months. Half of the time is assumed to be for transmission planning and half for protection engineering activities. |
| Individual |
| Thad Ness |
| American Electric Power |
| Method Section – In general, Steps 1 – 3 are confusing with the interchangeable use of “exclude”, “meeting attributes in Table” and “identified”. Starting off with confusing language and directives makes it difficult to determine and apply the proposed methodology. In Step 1, it is not clear who (the TP, TO or GO) has the responsibility to apply Table A criteria to develop the listing of busses. Also, in that determination, how would Entity A address busses or lines that are owned by another entity, that are connected to Entity A’s busses? From the proposed wording, it is not entirely clear that Steps 1-3 are to be applied to the bus listing obtained using Table A. As a suggestion, Step 1 should be to create a list of buses based on the criteria of Table A, and AEP suggests using more explicit language to make this clear. Step 2 would then be to use Table B as exclusion criteria for reducing the list of buses obtained using Table A. Step 3 would then simply state “Each Transmission Planner will simulate a three-phase fault on each bus in its transmission planning area, identified in |

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| step 1. The three-phase fault is cleared based on the following conservative simulation parameters:….”. Page 6: Wording of bullet one is confusing, as it is unclear how the test is going to use Table B (buses included or buses excluded). This bullet should be re-worded to indicate that Table B provides protection system attributes for exclusion. Page 6: The second bullet of Step 1 should be eliminated as this does not come into play until the Step 2. Page 6: In Step 2, the text “identified in step 1” should be replaced with “not excluded in step 1”. Page 6: In Step 2, for further simulations, which Planning Horizon is to be used? Also, are future improvements, not yet in service, to be included? Page 7: Step 5 should be reworded to match step 3 and 4. For example, The Transmission Owner and the Generator Owner will provide the Transmission Planner with actual clearing times... Page 7: Step 5 – The statement “…actual clearing times for all elements that will trip...” makes it unclear if this step is adding to scope elements in addition to those for which maximum expected clearing times where provided in Step 2. Page 9: Table B: Within the Protective Relays section, a definition of “independent protective relays” is needed. Is this perhaps a protection system that utilizes a primary high speed scheme and a time delay back up, or might it be two completely redundantly functional systems? Page 9: Table B: DC Control Circuitry: delete the last phrase "or circuit breaker trip coils". Redundant trip coils are only necessary when redundant DC supplies are used. Otherwise circuit breaker failure schemes are sufficient as backup to a trip coil failure. Trip coil failure is only one of many types of circuit breaker failure, all of which must be included in system performance analysis by planning. Page 10, Table C, Item 1. A definition of “Stability” needs to be provided. Does it include both dynamic stability as well as steady state loading? Table B is written such that meeting or exceeding all criteria listed in Table B is the desirable condition. Table C is written such that meeting or exceeding any one criteria of Table C is the undesirable condition. The tables should be revised such that act of meeting or exceeding criteria of a table is consistent across all tables. Page 10, Table D. Please provide a definition of “centrally monitored.” What attributes must be met? The Protection Systems employed on the national electrical grid have been in place for decades and for the most part, do not include redundant, independent schemes, except possibly for EHV elements. Would it not reduce the amount of research and simulations required, if the steps were eliminated using the conservative parameters and simply used only the actual clearing times instead, with the elimination of known redundant EHV schemes? Then one could research the “as built” conditions for further exclusion. |
| It is not clear what the difference is between a “Transmission Transformer” and a “Step Down Transformer”. Please provide a more detailed definition for each. It is not evident in the Request for Data or Information document that there will be a need to segregate and classify each element (by protection system element and by type of element), beyond just busses, for completing the data spreadsheets. What is the actual benefit of knowing single points of failure by line, transformer or shunt device? That adds yet another tremendous resource drain to this exercise. Buses Evaluated – This tab is confusing by the mixed use of meeting or exceeding criteria in Tables B and C, as previously mentioned. Row 4 requires reporting the number of buses where “…system performance exceeds one or more Performance Measures in Table C” (not desirable), while Row 6 requires reporting the number of buses where “…Protection System design for all Elements terminated at the bus meet all of the specified Protection System attributes in Table B” (desirable). Buses Evaluated – It would be beneficial to have the TP report on the number of buses that failed to meet the system performance criteria when utilizing maximum expected clearing times in addition to those that failed to meet the system performance criteria when utilizing actual clearing times. Buses Evaluated –The value of Row 5 “Total number of buses at which Protection System design was evaluated by the Transmission and Generator Owners:” would be less than the value of Row 2 “Total number of buses that meet the criteria in Table A, "Buses to be Evaluated," in the transmission planning area:”. The TO or GO would need to evaluate the Protection System design of the bus to confirm it meets all criteria of Table B and to have it excluded from the study. All tabs except the “Buses Evaluated” and “Station DC Supply” have similar entries for Note 1 stating that of the value in Row 1 of the tab “This number should be equal to the number of Transmission Lines terminated at the buses referenced in Row 5 of the "Buses Evaluated" tab.” This statement appears to be a typographical error as the sum of these elements may exceed the total number of busses evaluated. |
| As stated in the draft, “This data request will impose a substantial burden on the submitting entities.” We agree, the burden that this data request places upon Planner and Owner resources is very substantial, yet NERC has made no estimation to quantify the impact on the industry. 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 |

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| a much greater impact on the reliability of the BES. The execution of the survey process will require coordination between business units 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 with the TP provides the results to NERC. As a result of the tremendous effort required to respond to this data request, we suggest that to time to respond be extended to at least 24 months. |
| It is not clear what the exact nature is of the 4th, 7th, and 10th month updates. Please provide the format of these periodic updates. In addition, what is the value of providing such frequent updates? |
| Individual |
| Martyn Turner |
| LCRA Transmission Services Corporation |
| Although LCRA TSC believes that current NERC Reliability Standards already provide a basis for ensuring comprehensive reliability assessments, LCRA TSC agrees that where the potential for these conditions (non operation of a non-redundant protective relay system) exist, assessment and/or other types of requirements should be in place to ensure the reliability of the Bulk Electric System. LCRA TSC believes that the NERC-suggested data request method will ultimately result in helping the industry to "…understand the extent of any reliability gap and guide any efforts to address any such reliability gap.." Responding to this data request effort is a substantial undertaking within the time period suggested by NERC. LCRA TSC appreciates the filtering NERC is presently suggesting (Table A of the survey document) to help manage the anticipated level of work. LCRA TSC suggests the following additional filtering for consideration by NERC in implementing this data request: A. Availability of installed breaker failure protection should be added to Table B. B. Take into consideration the actual bus arrangement. To provide added reliability, Transmission Owners may already have in place bus configurations that provide higher levels of reliability such as a ring bus, breaker-and-a-half, or double bus-double breaker. Ignoring the inherent risk mitigation resulting from these bus designs will falsely represent the extent of the reliability gap this effort is trying to establish. C. Exempt radial transmission lines operating less than 200-kV. Treat a load-serving radial transmission line operating at less than 200-kV as a step-down transformer and therefore it is not counted as an element connected to the bus. D. Exempt those facilities that are governed by state, local, or regional standards where the need for redundant protective relay systems for new construction is a requirement. For example, those systems that are presently meeting obligations above and beyond the NERC Reliability Standards associated with protective relay system design. E. Exempt facilities for which past simulation tests have been conducted and limit testing reporting to summary of past test results. Such tests may include loss of bus assessments. F. Exclude step-down transformers. |
| A. An electronic reporting format is preferred. B. Exclude tab titled "Step Down Transformers". C. For transformers, redefine as follows to be consistent with NERC's BES definition: "Transformers with the primary terminal and at least one secondary terminal operated at 100-kV or higher." |
| A. To more accurately indicate the extent of this potential gap in reliability, increase the project period to 18 months. First, there may be a significant number of stations containing facilities owned by multiple entities and data reporting in response to the survey will have to be coordinated to eliminate double counting. Second, 18 months allows better coordination of resources that will have to both assist with this data request and support entity's annual planning cycles. The first 12 months may be reserved for data collection and the last 6 months may be designated for simulation test and final reporting. B. Eliminate interim / periodic reporting noted at 4th, 7th, and 10th months as this adds little to no value to the data request effort. C. The Method described in the Request for Data or Information is too prescriptive (and iterative) limiting any flexibility individual participants may consider to achieve the same results with a more efficient process. Instead, consider a method that establishes deadlines for when Transmission / Generation Owners make data available to Transmission Planners. The iterative process can lead to "required" inefficiencies. If it needs to prescriptive, then eliminate the iterative process by: i. Combining items 2, 6, and 7 resulting in one test conducted by the planner. ii. Combining items 1, 3, 4, 5, and 8 resulting in one data preparation effort by the owners. D. In the Survey document, the section describing the Method must identify deadlines for the Transmission and / or Generation Owner to provide data to Transmission Planner. LCRA TSC suggests no less than three months be allowed to conduct the simulation tests. |
| A. Allow Transmission Planner to simulate effects of installed automatic load shedding schemes or |

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| special protection systems. B. To assist in keeping results consistent, the Request for Data or Information must provide guidance on which case (year / season) the Transmission Planner should utilize as well as how to consider projects in progress or planned. C. In the Survey document, the section describing the Method should include a flow chart illustrating the process. D. To increase the efficiency and reduce cost associated with the data request effort, LCRA TSC suggests that the registered Planning Authority for the region or the Regional Entity conduct the simulations in Table C. |
| Group |
| NERC Compliance |
| Louis Slade |
| Dominion generally supports the comments being submitted by EEI. However, Dominion suggests the following: Table A: An alternative method of selection of buses to be tested based on a short circuit MVA threshold instead of the criteria based on voltage and number of circuits. This is a more direct way of measuring a bus's connectedness to the system. Table C: Performance Measures While agreeing on EEI's comment on criteria 1 requiring specificity, the only criteria that should be used to identify SPOF is criteria 1 " System does not maintain stability". Criteria 2 and 3 should be removed since these are localized and don't have large area impact. |
| Dominion generally supports the comments being submitted by EEI. |
| Dominion generally supports the comments being submitted by EEI but suggests the period to provide data requested should be lengthened to 3 years. Dominion could also support a tiered approach (similar to that used in the FAC Alert) based upon the items identified in Table A. |
| Dominion generally supports the comments being submitted by EEI. |
| Group |
| LG&E and KU Services Company |
| Brent Ingebrigtson |
| LG&E and KU Services Company supports the 3 phase fault analysis requirement for buses identified in Table A in the data request however we are aware buses reported as exceeding the table C performance measures will in some bus configurations yield results beyond the level of reliability set forth in TPL-003 and TPL-004. |
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| LG&E and KU Services Company requests that NERC provide an option for an extension to be granted based on a request by a registered entity to the ERO. If an extension is requested, included should be a commitment by the registered entity to supply study data accumulated to date and an explanation for the request. |
| LG&E and KU Services Company suggests, similar to the webinar for the definition of buses to be tested, NERC provide examples of Table B Protection System Attributes to be evaluated. The purpose of the examples would be to clarify the intent to evaluate overall protection system performance on the transmission system, which would include local and remote backup protection, and not just redundancy of the local protection system on an individual element. |
| Individual |
| Amanda Underwood |
| Omaha Public Power District |
| The first sentence of step 2 is misworded. One possible way of correcting it would be to change the sentence to the following: 'Each Transmission Planner will simulate a three-phase fault on each bus in its transmission planning area identified in step 1 based on the Transmission Owner or Generator Owner finding that at least one protection system for any of the elements connected to the bus or for any of the physical bus(es), if any, does not meet all of the attributes for all categories in Table B, "Protection System Attributes to be Evaluated."' Revise the data request survey method to indicate that if mutually agreed upon by the Transmission Owners and Generator Owners, actual clearing times may be used instead of the maximum expected clearing times for step 2 of the data request survey method. This approach would reduce the burden on entities considering it may take an equivalent amount of time to evaluate maximum expected clearing times as it would actual clearing times. If this approach is permitted, then revise the data request survey method to indicate that if actual clearing times are used in step 2 of the method, steps 4 through 7 do not need to be performed. Please clarify the reasoning behind leaving a fault un-cleared in the simulation when the |

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| protection at the remote terminal of an element does not detect the fault or when a transformer does not have through fault protection. Please refer to footnote # 9 and the third bullet under step 2 in the data request survey method for the statements in question. It is felt that this approach may result in unrealistic instability cases since the transmission system external to the fault is not allowed to respond as designed in the simulation. For a real-time single point of failure event on the protection system a fault may be detected and cleared outside the remote ends. Please clarify Table A row 4 of the data request survey method. Does “aggregate generation” refer to generation directly connected to the bus or to generation connected to the bus through a step-up transformer? Please expand on Table C row 1 and footnote 14 to indicate the criteria that are to be used to determine whether the system does not maintain stability. Please clarify Table C row 2 of the data request survey method. Does the unintended system separation resulting in an island of 1,000 MW or more refer to loss of generation or load? |
| Please clarify row 5 in the “Buses Evaluated” tab. Should the number entered here be the summed total of all the buses evaluated by the Transmission Owners and Generator Owners in steps 1 and 4? The buses evaluated in step 4 represent a subset of those evaluated in step 1 so this appears to result in the double counting of some buses. Please clarify row 1 in the “Transmission Lines”, “Transmission Transformers”, “GSU Transformers”, “Step-down Transformers “and “Shunt Devices” tabs. Should the number entered here be a subset of the total number of elements terminated at the buses referenced in Row 5 of the "Buses Evaluated" tab? Please clarify row 1 of the “Buses” tab and how this data relates to the buses referenced in Row 5 of the "Buses Evaluated" tab as stated in note 1 of the “Buses” tab. |
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| Please specify which seasonal planning model is to be used for stability testing purposes and what factors are viewed as worst-case in the model selection process (load amounts, generation amounts, etc.). In regards to Table A and Table C in the data request survey method, is “generation” determined by the maximum gross generating capability, by the forecasted in-service gross generation amount in the seasonal planning model used for testing, or by something else? For example, if a bus has an aggregate maximum gross generating capability of 1,000 MW but only half this capacity is forecasted to be in-service in the seasonal planning model and the bus does not meet any other criteria as mentioned in Table A, is it omitted from testing? Similarly, in regards to Table A and Table C in the data request survey method, is “load” determined by the forecasted in-service load amount in the seasonal planning model used for testing or by something else? |
| Individual |
| Angela P Gaines |
| Portland General Electric Company |
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| Portland General Electric thanks you for the opportunity to submit comments. However, this is question. For Consequential Load Loss, please define the time that the load must be unserved to be counted as Consequential. Is it all load that is dropped for any duration, or can load that is dropped and then automatically picked up from another transmission facility, or radially from the same remote end, within some short period of time be omitted from the Consequential Load Loss determination? If so, what is the maximum restoration time? |
| Group |
| ACES Power Marketing Standards Collaborators |
| Jason Marshall |
| This data request does not seem to align with the apparent spirit of the FERC directive from Order 754. The directive did not contain any requirement to create a data request. Rather, the directive required FERC staff to meet with NERC and subject matter experts to explore the reliability concern and identify additional necessary actions. It also required NERC to submit an informational filing explaining if there is a single point of failure issue, what forum and process to use to address it and what priority it should be given. Identifying the priority is consistent with the recognition the Commissioners have expressed in several technical conferences to the need for NERC to prioritize its work. NERC has many competing priorities in protection sytem work. Because this data request will |

cause a significant burden on many of the same personnel that will be working on these competing requests and is not required for the informational filing, it appears that NERC has already given the subsequent work to be completed after the informational filing a high priority. Since the extent of the problem is not known, we believe it is premature to prioritize the post-informational filing work to such a high level at this point and that a significantly less burdensome approach needs to be taken. The data request goes significantly above and beyond what is needed and the same intent could be accomplished with significantly less burden by relying on existing studies. TPL-004-0 already requires the Transmission Planner and Planning Coordinator to study Category D contingencies that would produce "more severe system results or impacts" per R1.3.1. Thus, the Transmission Planner and Planning Coordinator are already completing the studies that would identify the buses that don't meet the performance measures in Table C. No additional buses for other contingencies need to be studied. For the buses from the tested Category D contingencies that do not meet the performance requirements, the equipment owners could review that set for single points of failure. This would likely be significantly fewer buses that the equipment owners would have to evaluate. If the end result was not fewer buses, the data request could still be restricted to only those buses from tested category D contingencies that meet Table A criteria. The data request appears to exceed the necessary requirements in section 1600 of the NERC Rules of Procedure. Section 1600.2.1 requires NERC to describe the data, how the data will be used, why it is necessary, and how the data will be collected and validated. Nowhere in the Rules of Procedure is there a requirement for the data request to describe how the applicable entities should calculate, determine and gather the data. The data request is too rigid and, as a result, may impose unnecessary burden on the applicable entities. This request goes beyond the "what" and defines a "how" the Transmission Planner and equipment owners must calculate and determine the data. It assumes the approach outlined is the best balanced approach across all applicable entities in North America and that none of the applicable entities have gathered any of the necessary input data or addressed the single point of failure issue in its TPL studies. If the Transmission Planner has already studied single points of failure in completing its TPL studies, it should have flexibility to present that information in the appropriate form. If any of the necessary input data has already been gathered but not necessarily in the exact steps or order of the outlined method in the data request, the applicable entities should have flexibility to provide the end result data. For example, the equipment owners may have already identified their single points of failure but the Transmission Planner will be unnecessarily obligated to perform the initial screening in step 2 rather than the Transmission Planner skipping to step 5 or 6. Step 1 mandates that Transmission Planner meets with the equipment owners. Since much, if not all, of this necessary coordination work can be completed via conference and email, we suggest changing "will meet" to "will work" in Step 1. Step 1 and Step 2 need to be revised to be consistent. As step 1 is worded now, it appears that a list of buses that does not meet Table A must be gathered. Step 2 then states that the test is to be run on the list of buses from Step 1. That means the test would be run on excluded buses when the purpose is to run the test in Step 2 on the list of buses included as a result of the criteria in Table A. While we agree treating all buses as straight buses is the simplest solution and will provide conservative results, an applicable entity should be allowed to model the buses in more detail if they choose. For instance, applicable entities may already model multiple buses to accurately assess their system for the TPL studies. For a breaker and a half scheme, the results assuming remote clearing on all lines on a straight bus will be significantly more conservative but may not represent how a single point of failure may occur. The single point of failure may only result on the circuits tied to the same bus with the bus side breaker clearing while the circuits on the other side of the common breakers may remain tied together. Entities should be free to model this more accurate situation if they so choose. Sufficient justification needs provided for the thresholds used in Table A and Table C. For example, steps 2 and 7 require that the transmission system meet the performance requirements in Table C which includes not losing more than 2000 MW of generation in the Eastern Interconnection. Why was 2000 MW selected? In Table A, why was 300 MW of consequential load loss selected and four circuits on buses 200 kV and higher? While page 11 explains that the performance thresholds are based on "characteristics of events that exhibit system performance attributes that could be similar to the Westwing event", it does not provide sufficient justification for the thresholds. First, does the statement only apply to Table C which are the performance measures or does it apply to Table A also. Secondly, what are the characteristics? Why are they not explained here? More information on the last page is necessary. It appears to be an approval form that the Transmission Planner is to use but we suggest a statement in the text of the request explaining this. Because the TPL studies must be completed by the Planning Coordinator, the drafting team should consider

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| targeting the Planning Coordinator. In many areas, the Transmission Planner may not be completing the studies but may rely on the Planning Coordinators based on various agreements. This is likely to be the case for areas with organized markets. Nowhere in the data request is the study horizon discussed. It seems that the goal would be to assess the system as it exists today. However, the data request recognizes that some of the TPL studies may be used to respond to the data request. The TPL studies will include planned equipment. The bottom line is that the applicable entities need to know what study horizon must be evaluated. We suggest changing "exceeds" in the last bullet in Step 2 to "does not meet". For items 2 and 3 in Table C, "exceeds" would be appropriate, but it is not appropriate for item 1. How does a simulated system response "exceed" instability? |
| For several criteria throughout the data reporting template, we suggest changing "exceeds" to "does not meet". For items 2 and 3 in Table C, "exceeds" would be appropriate, but it is not appropriate for item 1. How does a simulated system response "exceed" instability? No rationale is provided for much of the data needed in the Data Reporting Template contrary to Section 1601.2.1(i) which requires NERC to explain how the data will be used. How is the number of circuits terminated at the buses evaluated going to be used? How will they not be double counted if the both buses at the ends of transmission lines do not meet Table C performance measures? It is not clear if the data template is consistent with step 8 of the data request. Step 8 states the transmission planner will report data that include attributes of the station dc supply from Table D. We cannot find this data element in the the data reporting template. In the transmission transformers, GSU transformer, Step-down transformers and shunt devices tabs of the data template, the explanation for row 1 refers to the number of transmission lines terminated. It looks like a copy and paste error. Should the transformers in the transmission transformers tabs be limited to only those with through fault protection? The description in Row 5 could lead to double counting. It states that those buses for which the protection systems were evaluated in step 1 and step 4 are to be included here. It would seem that those buses evaluated in step 4 are a subset of step 1. Thus, only data from step 1 is needed. |
| For many entities, 12 months may not be sufficient enough time to comply with the data request. While we appreciate the drafting team trying to structure the request to allow a Transmission Planner to rely on its TPL studies, many Transmission Planners may have to complete a significant number of additional dynamics studies. The existing TPL studies do not require every category D contingency to be studied but rather allow the Transmission Planner and Planning Coordinator to select a subset of category D contingencies per TPL-004-1 R1.3.1. Thus, many entities may have to study a significant number of new contingencies. The TPL studies allow an annual period to complete these studies. Couple this with the fact that the data request will come out during a period where some Transmission Planners are well into their TPL study cycle and may need to wait until the next cycle to begin addressing the data request and there is a real possibility that the data request cannot be met in 12 months. Because Transmission Planners will complete their TPL studies on different cycles, it would be impossible for the data request to be timed to come early in every Transmission Planner's study cycle. If the drafting team ultimately determined these studies must be completed on the existing system, then even more study time will be required because existing TPL studies cover years 1 to 5 and the current year. |
| NERC Rules of Procedure section 1601.2.1(vi) require section 1600 data requests to include "an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request." We do not believe this requirement has been met. Indicating the burden will be substantial is not an estimate. Some of the purpose of providing an estimate is to help entities to know how many resources to allocate, to supply NERC with knowledge that can be used to assess if the data or information request is worth the burden, and to provide an appropriate schedule for the data request. How can the entities or NERC meet these rules with a vague statement that the burden will be substantial? |
| Individual |
| Kirit Shah |
| Ameren |
| Comments on Method :(1)In step 1, please clarify that the intent is to make the first cut at reducing the Table-A list by those locations meeting Table B with the first bullet. (2)In step 1, please clarify the second bullet is to then augment the list, we suggest "Also include only transmission transformers supplying external short circuits for which through-fault protection is only provided via remote detection and clearing." (3)Reword step 2 so that it is clear that the simulations are to be done for the bus list from step 1. (4) Allow entities to go directly to the actual clearing times steps, if they believe |

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| it to be more efficient. (5)The method and its language should address those busses that should be tested, not the busses that should be excluded. (6) We believe that the overall time can be reduced if the System Protection folks would provide the Transmission Planners with the actual remote clearing times and not the maximum expected remote clearing times. (refer to Table A, comment 4). (7) We do not believe that this would increase the burden on System Protection engineers significantly. It is suggested that the examples provided in the 2nd webinar be included in the instructions regarding which busses should be evaluated. (8)Step #7 ties back to step #2. It must be clear which busses are to be evaluated. (9) Why did the SDT decide not to split the assignment to > than 200 kV and then come back later and review 100 kV to 200 kV? Spending resources to review 100 kV to 200 kV facilities is believed to have local impacts only and should not result in cascade tripping of facilities. (10)Please explain that 'Step-down Transformers' refers to only those distribution transformers connected to Buses evaluated. Table A. (11)For Table A, only generator step-up transformers for a registered generation entity should count as a circuit. (12) The title in Table A does not match step #8 bullet 2. (13)There is no basis for treating radial lines that supply step down transformers differently than a direct bus connection for a step down transformer. Please add this to Table-A note. Comments on Table B : (14)Clarify the meaning of "no common dc control circuitry" within the Table B - DC Control Circuitry attribute. (15)Footnote 13 hyperlink does not work. Comments on Table C: (16)Is the intent of the study to look at the impact of slower than normal clearing for bus and close-in faults? If so will we need to review E/M step distance relay designs which have single zone-1, zone-2, and zone-3 relays? For example if the zone-1 relay fails for a close-in fault, clearing will be zone-2 time delay on the line and at remote terminals. (17)How can the performance measures in Table C be exceeded (see bullet 5 of step #2)? It appears that the Performance Measures in Table C are reasonable tests, but item #2 needs some clarification. |
| (1)The RFI should take precedence over the template instructions, if they conflict. (2)The template forces much extra work by asking for redundancy attributes of each 'circuit' type. This is burdensome and should be omitted. The approach stated on the 1/5/2012 webinar is that once we determine one redundancy attribute at a (planning) bus is not met, we need to include that bus, and can stop our research is much more efficient and strongly preferred. (3)Please explain that 'Step-down Transformers' refers to only those distribution transformers connected to Buses evaluated. (4) How can the system performance measures be exceeded (See Table-C "Performance Measures")? |
| (1)Why is there a need for Transmission Planners to acknowledge the data request? (2)Why is there a need for multiple status reports? The interim steps are of no use to NERC or FERC. (3)NERC should consider an appeal process that would allow a schedule extension if needed. |
| (1)FERC has just approved the Protection System definition in footnote 17 on 2/3/2012 and it is not effective until 4/1/2013, so the existing definition should be used. (2)Please add "Relay types are listed in note 13 on page 12" in footnote 18.(3)This RFI is a significant burden to entities. Given that only a few 'lack of Protection System redundancy' events have occurred in the last decade, it imposes a distraction of key resources at each entity which may well pose a greater risk to BES reliability than these extremely rare instances themselves. This burden could be eased by: (a)Extending the deadline from one to two years 9(b) Using a higher level screening criteria ( e.g. Table A could require six or more circuits rather than four or more circuits at 200kV or higher and could require eight or more circuits rather than six or more circuits at 100kV to 200kV ). (4)Why shouldn't all of the industry responses be considered as CEII? (5)Why is it necessary to mark the specific items as confidential? (6) Why is an attestation required for the submittal of the data? (7)Why should any supervisor approve the survey without knowing who provided the protection data for the Transmission owner or the Generation owner? (8) The responsibility to complete the data request should fall to all participants (Transmission Planners, Transmission Owners, and Generation Owners). Failure to complete the data request should not fall to only the Transmission Planners. |
| Individual |
| Wryan J. Feil |
| Northeast Utilities |
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| The project requires coordination between different departments that may not exist within the same organization (i.e., independent Transmission Owners and independent Generator Owners). It is suggested that the project period be increased to 24 months if the resolution to item #1 would |

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| require a new study analyzing all buses and coordinating between the different entities. |
| 1. This data request requires Transmission Planners to evaluate the risks associated with three-phase faults with delayed clearing. Can simulation studies performed to satisfy the A-10 analysis (BPS analysis) for entities within the NPCC footprint be used to satisfy this data request? 2. Table B, Communication Systems: Clarification is needed when a system with two independent protection systems, system A and system B, has communication link for system A and system B does not have communication, e.g., would it be acceptable if System B is an independent stepped distance protection scheme without communication between relays (where a fault at one end of a protected transmission line, and with system A out, would be cleared in zone 2 actual time at the other end of the line by system B)? 3. The project requires coordination between different departments that may not exist within the same organization (i.e., independent Transmission Owners and independent Generator Owners). It is suggested that the project period be increased to 24 months if the resolution to item #1 would require a new study analyzing all buses and coordinating between the different entities. 4. Step #1 and step #2 under the section titled “Method” needs better clarification. It seems step #1 is in conflict with step #2. Shouldn’t the statement “….. if any, meet the attributes for all categories in Table B, …” in step #2 be rephrased to “… if any, do not meet the attributes for all categories in Table B, …”. Otherwise it seems that buses excluded under Step 1 would have to still be tested under Step 2, thus negating the ability to exclude buses. |
| Individual |
| Bill Middaugh |
| Tri-State G&T |
| In general, the current version of this data request is wordy, confusing, and worse, micromanages the process organizations would use to determine the BES impact of failed non-redundant protection systems. The most efficient approach would be for NERC to scope the data needs and leave the process and details for obtaining that data up to the applicable system experts. In keeping with this, it is recommended to change the core of the data request as follows: 1) Rename Table B to “Protection System Components to be Evaluated” 2) Add the following sentence to the fourth cell in Table B: “A redundant protection system may include a single battery and charging system provided it is centrally monitored and includes alarming for a battery open condition if the station DC supply is a battery.” 3) Keep Table C as is 4) Delete Table D 5) Replace steps 1 through 7 in the “Method” section with (or something like this): “Using a stressed operating case and expected protection system clearing times, determine which relevant transmission elements, as described in Table A, that if subjected to a three phase fault coupled with a failed non-redundant protection system, as defined in Table B, would result in a violation of the performance measures described in Table C.” |
| We believe the format should remain a spreadsheet that can be reviewed by as many people as necessary and then submitted whole, without having to copy and paste sections to an electronic form. The spreadsheet has potentially too many fields to accommodate in an on-line form. |
| The schedule is not specific enough to know when reports are due since they are listed by month and not a specific day of the month. However, we question the need for interim reports (4th, 7th, and 10th months). If no recourse for extending the final report is available, why are interim reports of any value? We also disagree with using an electronic data report rather than submission of the template. |
| Step 1 calls for identification of which buses can be excluded from testing. Step 2 calls for testing all the buses identified in Step 1. This is clearly an oversight. Step 2 should be reworded to call for testing of all buses meeting the criteria in Table A. except for those that are identified to be excluded in Step 1. Can radial lines be excluded as a circuit when determining which buses need to be tested (Table A) similar to not including radial distribution transformers? It does not makes sense to require two studies where the first is to use “maximum expected remote clearing time” (Step 2) and the second is to use the “actual clearing time” (Step 6). Just use actual clearing times and be done. |
| Group |
| IRC Standards Review Committee |
| Charles Yeung |
| The ISO RTO Council members are concerned that NERC is using the Rules of Procedure to collect data without first justifying the industry costs and the reliability benefits of the data request. The ISO RTO Council agrees with EEI’s concerns regarding the use of Section 1600 of the NERC Rules of Procedure for data requests. The Data Request goes beyond what is allowed by Section 1600 of the ROP “The provisions of Section 1600 shall not apply to requirements contained in any Reliability |

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| Standard to provide data or information; the requirements in the Reliability Standards govern." NERC did not meet the essential criteria as defined in Section 1602.2.1: "(vi) an estimate of the relative burden imposed on the reporting entities to accommodate the data or information request." o This data request only states that the request "will impose a substantial burden on the submitting entities." and does not offer any estimates of that burden as specified. |
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| NERC should capture the cost of the collection effort and show some tangible outcome (report or analysis) for the effort. Resources will have to be expended for entities to respond and may not be for best use if the data is not utilized in a meaningful way or if there are other ways to make an assessment without making an extensive data request. Part of the data submission should be that the entities report the approximate time (man-hours) expended in collecting this data. This information will be helpful to make future decisions (on similar data requests or if it is proposed to make this a recurring request). Knowing the cost helps preclude data requests for the same issue becoming annual exercises, particularly if nothing concrete is learned and shared from the first round of collection. We never saw the result of the generator recommendation (governor alert nor have we seen results from the IROL exceedence information which was initiated by a FERC comment that entities were going in and out of IROLs or waiting 29 minutes before correcting IROLs, yet this information is still being reported with no defined purpose or reliability outcome). |
| Group |
| Progress Energy |
| Jim Eckelkamp |
| Progress Energy supports EEI comments |
| Progress Energy supports EEI comments |
| If a fixed time period remains for responding to the survey then PE believes that a significant longer time period is needed than the proposed twelve (12) months, possibly as long as 24 months. |
| Progress Energy supports EEI comments |
| Individual |
| Armin Klusman |
| CenterPoint Energy |
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| CenterPoint Energy recommends that Reliability Coordinators be designated as the entities responsible for responding to the proposed data request. This request requires coordination of multiple types of functional entities and, by definition, Reliability Coordinators are better situated to respond. Furthermore, designating Reliability Coordinators as the responsible entity would provide consistent data reporting. CenterPoint Energy notes that the Westwing Outage of June 14, 2004 (Category 3 outage), the Broad River Disturbance of August 25, 2007 (Category 2 outage), and the PacifiCorp East Disturbance of February 14, 2008 (Category 3 outage) were attributed to the failure of a single auxiliary, or lockout relay, used for tripping circuit breakers. Also, these three disturbances involved stations rated greater than 200 kV. CenterPoint Energy recommends the following changes to the proposed request for data and believes these changes result in an approach that more accurately reflects the level of risk indicated in the disturbances cited by NERC. This approach would also reduce the burden of complying with the request, but would still determine whether there is actually a reliability concern. • In Table A 'Buses to be Tested', delete "Buses operated at 100 kV to 200 kV with 6 or more circuits" • In Table A, for the item "Buses operated at 100 kV or greater with 4 or more circuits and at which a bus fault and tripping of all connected elements at the remote terminals will result in 300 MW or more of consequential load loss as a result of remote clearing", change 100 kV to 200 kV. • In Table A, change the criteria for buses to be evaluated from buses with aggregate generation of 1,000 MW to buses with aggregate generation of 2,000 MW. Generation operating reserves can vary by region, but it is not uncommon for individual generating units to exceed 1,000 MW and for the region to operate with enough reserves to withstand the loss of more than one individual unit for a wide variety of reasons that are much more common that a protection |

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| system failure. CenterPoint Energy believes all or most regions maintain reserves exceeding 2,000 MW. As a practical matter, if a bus connecting generation to the BES does not meet the number of circuits criteria in Table A, it is highly unlikely that loss of the associated generation is material to BES reliability. Therefore, an alternative approach would be to delete the generation level criterion altogether. • In Table B 'Protection System Attributes to be Evaluated', delete all items except for auxiliary relays and clarify that the auxiliary relays are tripping relays. • In Table C 'Performance Measures', CenterPoint Energy recommends that item 3, the proposed loss of generation criteria, be deleted or, if retained, be increased from the proposed levels to 3000 MW. In the ERCOT interconnection, for example, there are several units with capability exceeding 1,200 MW, so loss of 1,200 MW of generation can occur under Category B conditions (loss of a single generating unit). CenterPoint Energy bases this recommendation on the fact that operating reserve requirements generally range from 2,000 to 3,000 MW, and most of the time actual reserves greatly exceed the reserve requirement. |
| Individual |
| Bradley Collard |
| Oncor Electric Delivery LLC |
| Oncor will support and consider all recommendations to ensure that the Oncor transmission system is secure and can perform at optimum levels during all contingent situations. NERC Order 754 Data Request (Request) requests an enormous amount of data that will require a vast amount of work hours, with companies that have a larger BES footprint incurring an exponential amount of additional work. Oncor also supports EEI position found in their general comments and strongly agrees with the following: "We also support the intended purpose of the data request which we find in its "Method" seeks to limit the burden on entities while satisfying Commission concerns. However, we remain concerned that the effort will divert scarce manpower from other necessary tasks complicating some entity's ability to perform other critical duties. One possible solution might be to allow entities to file for an extension of their data submittal on the grounds that the request is a hardship. Obviously, entities would need to adequately justify such a request in order to obtain the necessary approval." Oncor believes this Request will require it to divert key Protection and Planning personnel needed to perform required reliability related tasks and would like NERC to consider a much longer schedule needed to complete the Request. Step 1 – Oncor does agree that there should be open communication between Oncor and the Generator Owners (GO) in the Oncor footprint; however, the proposed Request appears to assume that the Transmission Planner (TP) provides coordination functions for the respective Transmission Owners (TO) and GO in the TP area. Since the TP function cannot take place until after the TOs and GOs perform the necessary work of evaluating their systems, the Scheduled Reporting table included in the Request seems to be overly aggressive and impractical. Oncor position mirrors EEI's sentiments for Step 1 found in the following statement: Step 1 –EEI acknowledges the need for meetings between TPs, TOs and GOs recognizing this as a necessary first step, however, we are concerned that this effort will be a very long and time consuming task which could take months for some very large TPs to complete. It is our recommendation that the Data Request make some accommodations to address this likely hardship. Step 2 – Step 2 of the Request appears to state that 3-phase faults need to be run on all buses identified in Step 1. However, Oncor believes Step 1 asks all TPs to identify all buses "that can be excluded from testing." Taken together, Step 1 and Step 2 seem to contradict the purpose of the Request of evaluating all buses "on which a three-phase fault accompanied by a protection system failure, that could result in a potential reliability risk". Oncor believes Step 2 should be rewritten to evaluate all buses from Table A not identified in Step 1 as exclusions. Step 8 – Oncor believes the "as-built" information should be supplied at the beginning of the process so the TP can have all pertinent information prior to performing any studies. In the process of evaluating which buses meet the criteria of Table A, the TO and GO will need to evaluate all of this information before supplying applicable buses to the TP. If that information is already determined at the start of the process, it can be passed along to the TP at that point. Table A – It appears this table is more burdensome than the guidelines already specified in the existing NERC TPL Standards. The scenarios listed in Table A appear to be very similar to Category D contingencies listed in Table 1 of the existing NERC TPL standards. As such, Oncor believes that NERC is either 1) asking that TPs perform repetitive work that is already being performed or 2) compelling work that is contradictory to existing guidelines specified in note D, Table 1 of the existing NERC TPL standards. Oncor feels that the study guidelines in the NERC TPL-001 through NERC TPL-004 Standards are currently sufficient to study the Bulk Electric |

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| System. Table C – Item 2 of Table C does not clearly indicate that there is a necessary reliability risk with the electric system. A 1,000 MW island could possibly still operate in a stable fashion. It appears that the scenarios listed in Table C are not analogous to the level of concern needed for a study of possible or potential reliability risks. Oncor believes NERC and the TPs performing the work for the proposed Request would be better served if NERC provided the TPs with a goal of what the TP studies are to ascertain. However, in Steps 3 through 6 the Request attempts to direct TPs on a step-by-step process of how they are to perform their studies. Many TPs may already have processes that are much more efficient and effective than the process submitted in the proposed Request. Oncor would like to see verbiage similar to that which is already provided in the current NERC TPL standards instead of a step-by-step study process. Generally, Oncor feels that the NERC 754 proposed method is overly cumbersome and will require a significant amount of additional manhours for a large TO to evaluate their entire system for redundancy in protective relaying, redundancy in communication systems, redundancy in AC Current and Voltage Inputs and redundancy in DC Control Circuitry. After that information is collected, an undue amount of work, and in most cases duplicative work performed for the existing TPL standards, will be mandated on the TPs to run additional studies to meet the required data collection for the NERC 754 Request, especially for those TPs that manage a large BES footprint. |
| Oncor believes that some of the information requested on the proposed template is redundant and should be removed. Specifically, item 5 on the “Buses Evaluated” spreadsheet appears to be identical to item 1 on the “Buses” spreadsheet. Additionally, item 6 on the “Buses Evaluated” spreadsheet appears to be identical to item 2 on the “Buses” spreadsheet. Oncor questions the rationale of asking organizations to place the same data on multiple sheets of a data submittal form. It would appear that entering the data in one place would be enough to highlight any possible problems. |
| Oncor believes the schedule in the proposed Request is overly aggressive and tenuous, because of the burden placed on the TO and TP functions. In an organization the size of Oncor, a large amount of TO function man hours will be needed to ensure that the data provided to the TP function is accurate. The additional workload required to meet the proposed timeline places an onerous burden on the TO organization prior to handing the data off to the TP function. Due to the necessity of different groups, (TO, GO and TP), providing input to the Request, the schedule seems to be a serial process, as opposed to a process where all three group representatives can be performing work simultaneously. This will necessarily lengthen the time required to produce a completed process. Oncor would recommend a process that is outlined in more detail with TO and GO functions separated from the TP function. As the Request states, “the entity responsible for coordinating the fulfillment of the data request will be the Transmission Planner”. Regarding the schedule, Oncor believes this puts unjustified demand on the TP since the TO and GO have to provide the initial data. If the TO and GO do not provide timely data submittals to the TP, the TP is the entity held responsible for an untimely or flawed submittal of the Request. Oncor believes a more detailed schedule that includes specific TO and GO information submittal requirements would benefit the process. Otherwise, the TPs are at the mercy of the TO and GO submittal timelines and the TO and GO reaction to requests by the respective TPs. Oncor believes that larger TPs have a more burdensome process, as described in the Request, than smaller TP entities, almost to an exponential level. As such, the larger TPs, which have to deal with a wider range of TOs and GOs, will have a more difficult time meeting the given schedule. |
| Intentionally left blank. |
| Individual |
| Andrew Z Pusztai |
| American Transmission Company, LLC |
| ATC supports comments submitted by EEI. In addition, ATC submits the following comments: Step 0 • The first step of the “Method” is missing. Step 1 should state that “Each Transmission Planner will apply the criteria in Table A to create an initial list of “Buses to be Studied”. This step has a crucial impact on how much work must be done for the next three steps. • The number and percentage of “Buses to be Studied” is expected to vary considerably among entities. The proposed Table A criteria leads to the selection of a high number of buses that would require a very burdensome expenditure of resources that may be unnecessary to develop in the final list. ATC offers the following modifications to Table A Criteria: Buses to be Studied: o Buses operated at 200 kV or higher with 8 or more circuits o Buses operated at 100 kV or higher with 10 or more circuits o Buses operated at 100 kV or higher with 8 or more circuits which could result in 300 MW or more of consequential load loss o Buses with aggregate generation of 1,000 MW or higher o Buses directly supplying off-site power to a nuclear |

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| plant • Provide more guidance/instructions regarding the characteristics of qualifying circuits to assure that responding entities are consistent. o Consider whether circuits (even non-BES circuits) which network back to the BES should be counted o Consider whether circuits that lead to radial connected islands with significant generation should be counted. Step 2 • If the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive and beyond scope of what should be appropriate for NERC Rules of Procedure (ROP), Section 1602.2.1. • Criteria 1 in Table C appears to only refer to angular system instability and the resulting trip of loss of more the 1,000 MW of generation. Voltage instability on the other hand could result in the loss of load, generation, or both. Criteria 1 does not provide guidance regarding what level(s) of angular instability, voltage instability, or both are appropriate to determine significant enough system instability. • Criterion 2 in Table C refers to formation of an island, but does not give consideration to whether resulting island would collapse or become stable. Step 6 • As noted in Step 2, if the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive and beyond scope of what should be appropriate for NERC ROP, Section 1602.2.1. Step 7 • As noted in Step 2, Criteria 1 in Table C appears to only refer to angular system instability and the resulting trip of loss of more the 1,000 MW of generation. Voltage instability on the other hand could result in the loss of load, generation, or both. Criteria 1 does not provide guidance regarding what level(s) of angular instability, voltage instability, or both are appropriate to determine significant enough system instability. |
| ATC supports comments submitted by EEI. |
| ATC supports comments submitted by EEI. In addition, ATC submits the following specific comments: • If the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive and some entities might have so many “Buses to be Studied” that they cannot complete the work within 12 months and meet their mandatory requirements. • If the more restrictive Table A criteria suggested above is not accepted, then resource burden to perform the requested simulations is expected to be excessive for many entities might have to hire consultants to complete the amount of work for the request in the requested time frame. Are there enough consultants or resources available if many entities have to hire help? |
| ATC supports comments submitted by EEI. In addition, ATC submits the following specific comments: • The method involves more than providing existing ‘look up’ data. It involves the performance of simulation work that could be significant burden to entity resources. The request for unbounded power system simulation work may be beyond the scope of what is allowed by NERC ROP Section 1602.2.1. • Perhaps it should be acknowledged that steady state analysis (which takes less time) may be used to establish that a bus meets one of Table C performance criteria, but dynamic analysis is required to establish that a bus does not meet any of the Table C performance criteria. |
| Group |
| PacifiCorp |
| Sandra Shaffer |
| The working group is to be commended for its thoughtful effort to appropriately respond to the FERC’s concerns regarding “…the study of the non-operation of non-redundant primary protection systems.” However, PacifiCorp believes the request for data and information casts a wider net than necessary in order to provide an adequate as well as informative response. The working group itself notes that “This data request will impose a substantial burden on the submitting entities.” By limiting the scope of this request, the burden to reporting entities will be significantly reduced and their efforts will be focused on the areas of greatest impact and concern. The draft data request states, “The protection system components of interest include any component that could possibly result in delayed clearing of a fault due to a single protection system component failure.” The protection systems identified for evaluation and reporting (Tables B and D) include protective relays, communications systems, AC current and voltage systems, DC control circuitry, as well as station DC supply. The data request is apparently based on recommendations from the technical paper, “Protection System Reliability Redundancy of Protection System Elements” prepared by the NERC System Protection and Control Task Force in November of 2008. As of this writing, no standard has been developed from these recommendations. Rather, the current Transmission Planning Standard TPL-003-0a addresses this concern in Table 1, Categories C6-C9 (“SLG Fault, with Delayed Clearing (stuck breaker or protection system failure)”). Additional clarification is provided in footnote e which states, “Delayed clearing of a |

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| Fault is due to failure of any protection system component such as a relay, circuit breaker, or current transformer, and not because of an intentional design delay." Further explanation is provided in the new, pending TPL-001-2 planning standard for Category P5 contingencies ("Delayed Fault Clearing due to the failure of a non-redundant relay"). Footnote 13 states that it applies to failure of the following relay functions or types: pilot (#85), distance (#21), differential (#87), current (#50, 51, and 67), voltage (#27 and 59), directional (#32 and 67), and tripping (#86 and 94). The failure mechanism involved in the recent disturbances cited as the rationale for the request were to non-redundant tripping relays (#84 and 94). If recent experience can be used as a guide (i.e., the Westwing, Broadview, and PacifiCorp East disturbances), the latter category of non-redundant tripping relays appears to pose a more credible risk to the reliability of the BES than many of the other items listed; therefore, PacifiCorp suggests that the request be limited to soliciting data and information regarding non-redundant tripping relays in critical substations and switchyards. In the draft data request, step 1 of the 9 step draft procedure limits the evaluation to a set of buses that meet the selection criteria set forth in Table A of the document. Once this subset has been identified, step 2 directs the Transmission Planner to simulate a three-phase fault with delayed clearing on each identified bus to see if the subsequent simulated performance falls into any of the categories listed in Table C. Three phase faults with delayed clearing are easy to simulate since only the positive sequence is used, but the results of simulations with significantly delayed clearing can be problematic since a three phase fault with no fault impedance drives the voltage to zero at the point of the fault. An actual long duration three phase fault will cause significant loss of customer load simply due to motor contactors dropping out, etc. However, this phenomenon is not generally represented in simulations because detailed model information about individual small customer loads is generally unavailable and, in the Western Interconnection, the models which can be used to simulate this behavior are still in the development stage. In addition, the accuracy of many of the machine models may degrade when used to simulate extended operation under very low voltage conditions. Since this type of disturbance is presently assessed only for 'risks and consequences' under Category D (TPL-004-1), this loss of modeling accuracy is acceptable. However, the draft proposal suggests that this information will be used to assess the risk for non-operation of non-redundant primary protection systems for Category B contingencies. PacifiCorp believes that this substitution reaches beyond the existing performance standards and could result in misleading conclusions. Therefore, PacifiCorp would like to offer the following alternative evaluation methodology. The three phase Thevenin impedance at an electrical bus is the equivalent system impedance between the point of a fault on the bus of interest and the driving voltages at all of the generators on-line at the time of the fault. The lower the impedance, the higher the fault currents will be and, by extension, the greater the impact to the BES of a fault. This impact can be expressed as short-circuit MVA (SCMVA) . For illustration purposes, there are approximately 16,000 buses represented in the Western Electricity Coordinating Council (WECC) 2009 HS3 power flow base case, and the voltage at approximately half are 100 kV or greater. The SCSC function of the General Electric Positive Sequence Load Flow power flow program was used to estimate the three-phase SCMVA at these buses using certain simplifying assumptions. This information is summarized in Figure 1 and shows separate curves for SCMVA data by specified voltage ranges. As Figure 1 shows, (sent in a separate email since this form does not accept graphs), the SCMVA varies significantly, and, as expected, the highest values are concentrated at the highest voltages. For illustration, the SCMVA values at the buses associated with two disturbances for which data is available of the three disturbances identified in the 2009 NERC Industry Advisory regarding Protection System Single Point of Failure are estimated to be approximately 11,000 MVA and 22,000 MVA. This implies that buses of greatest interest with respect to this request should be those with the highest SCMVA. While the proposed 9-step methodology, once complete, may result in identifying the same buses, this selection criterion is much simpler, and the data required to identify the buses of interest is readily available without additional study. Since SCMVA data is readily available, it should be used rather than requiring entities to perform additional studies. PacifiCorp suggests that the number of buses be further limited by requiring entities to report only on a maximum of up to five of their substations or switchyards with SCMVA values greater than 8000 MVA. This will reduce the reporting requirements since many smaller entities will not have buses with SCMVA values greater than 8000 MVA, and larger entities are more likely to have the resources to adequately and timely respond to this request if reduced as proposed. |
| PacifiCorp believes the request for data and information casts a wider net than necessary in order to provide an adequate as well as informative response. Therefore, PacifiCorp suggests an alternative that is described in response to question 1 above. This change will require revisions to the reporting |

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| template. |
| If the scope of work is not reduced as suggested in the response to question 1 above, the proposed reporting schedule will have to be modified. However, the overall timeframe will be adequate if the scope of work is reduced. As written, the amount of work required by this data request is significant. To do the work required as a stand alone project (in addition to our ongoing required tasks) will be difficult and potentially disruptive to PacifiCorp. This potential disruption would be minimized if this work could be made part of our yearly system assessments which are performed in order to meet the compliance requirements of the TPL Standards. To that end, we propose that an 18 month schedule be considered for meeting the requirements of this data request. With that schedule, we could perform the preliminary analysis/data gathering as we perform our 2012 system assessment and complete the data request by performing our 2013 system assessment. A completion date of late 2013 would allow for the inclusion of this data request as part of our existing system assessment work and minimize the impact to our organization. |
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| Individual |
| Michelle D'Antuono |
| Ingleside Cogeneration LP |
| Ingleside Cogeneration believes that the method proposed by the project team requires the immediate involvement of far too many Generator Owners. This results mostly from a determination of the criticality of buses operating below 200 kV which is based upon the number of circuits attached to them. A good rationale has not been given for this threshold, only that it appears to be an educated guess by the project team. Instead of creating new criticality criteria, we believe there has already been a precedent established under PRC-023-1. In that Standard, circuits which operate below 200 kV are considered to be non-critical unless they have been identified otherwise by the Planning Authority. It seems to us that the owners of those facilities could be brought into this process quickly and effectively as they are already far more familiar with the planning process. If the results of a study performed using the circuits identified as critical under PRC-023-1 determine that further sub-200 kV generator interconnections should be evaluated, then more Generator Owners could be brought in at that time. It is reasonable to assume that many of the inconsistencies would be worked out of the process by then – allowing a far more efficient means of coordinating the efforts of a large number of smaller entities. |
| The form appears to capture the information needed by the project team to assess the risk of single points of Protection System failures BES-wide. However, it is written from the perspective of the Planning Coordinator, who will summarize the information across multiple Transmission Owners and Generator Owners. As a result, it is difficult for us as a GO to accurately assess the effort required to collect and file the information with the Planning Coordinator required in steps 1, 3, and 8 of the process. As it stands now, we believe the complexity of the data request will require significant engineering and process support resource time – even for those GOs who find that they have no critical busses, and do not need to proceed beyond step 1. |
| The schedule is heavily dependent on the Planning Coordinator’s ability to distribute and collect requests for information – and perform complex studies on each submission. All during this time, it is reasonable to assume that the PC’s will be asking clarifications of GOs and TOs; and responding to their questions as well. The effort may further require face to face meetings, conference calls, and/or webinars to get all participants organized. This coordination effort will become increasingly more difficult later in the project as the data needs become far more complex. This means that some flexibility must be available in the schedule to ensure that PC, GO, and TO support personnel are available. They must perform many other tasks which also protect the reliability of the Bulk Electric System – and may not be able to devote the time needed to conduct intensive analyses of Protection System components. |
| The fundamental concern that Ingleside Cogeneration LP has with this project is that it is chasing a perceived risk – not one supported by data. We understand that the potential to impact wide-areas of the BES is possible wherever a single Protection System element impact many other elements – but the evidence that this should supplant other priorities is not compelling. Furthermore, we don’t deny that FERC has been driving this action – and has the legal authority to mandate it – but it will require technical resources which are always in short supply. With projects on the horizon to validate generator performance, coordinate frequency ride-through settings with UFLS settings, and other |

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| similar initiatives; it is hard to justify new programs that do not clearly support significant improvements in BES reliability. |
| Group |
| Kansas City Power & Light |
| Harold Wyble |
| a. Steps 4, 5 and 6 should come before any studies are conducted in step 2. Without the specific information regarding relay clearing times, the studies cannot be conducted. Removing buses that have sufficient redundancy as indicated in Table B should be removed prior to performing the studies to prevent unnecessary analysis burden to the Transmission Planner. b. Step 7 states that the final list will include buses that exceed any of the three performance measures in Table C. The criteria for these measures are based on an event reporting system and not on any standards. If an island is formed of 1,000 MW or more, why is this equal in reporting priority to a system that does not maintain stability? It is quite possible that studies can prove that if generation equals load within the island than it is a minimal reliability risk. c. Table A lacks clarity in what is meant by the third item in the table. The current description could be misconstrued as the total loss of all busses in a substation and the loss of the busses at remote substations connected by elements that terminate between the substations. If that is the intended meaning, then this condition exceeds the scope of the “single point of failure” this data request represents. d. Table A lacks clarity in what is meant by, “buses with aggregate generation of 1,000 MW or higher” in the fourth item in the table. The current description could be misconstrued as the totality of generation for all buses in a substation and not on a per bus basis within the station. If that is the intended meaning, then this description exceeds the scope of the “single point of failure” this data request represents. e. Remove the sixth item in Table A. If there is additional reliability criteria that needs consideration, then Table A should reflect that, otherwise this item is too broad and will lead to interpretation and debate. f. Item 2 in Table B should be removed. Systems that have redundant relaying may not have redundant communication systems and rely on the clearing times designated by the secondary relaying. The TPL studies already require Entities to utilize longer clearing times as a contingency condition so this is not necessary to include here. Further, this items suggests the TPL standards include criteria to determine a need for redundant communication channels. Please specify this TPL reference that determines this. g. The phrase, “as built” is used several times. This can be troublesome without definition. Please specify what is meant by, “as built”. |
| Provide a comment field for Entities to clarify responses if need be. |
| KCP&L is concerned regarding the 12 month reporting requirement. Considering the amount of data gathering and the dynamic analysis that may be involved for some Entities, 12 months could be too aggressive. Entities are already stretched thin with the operating and planning burdens imposed upon them. KCP&L recommends NERC give consideration to allowing Entities to specify the schedule they can maintain and include that in an initial report submission much like what has already been done with other data gathering and reporting actions through some of the NERC Alerts. |
| KCP&L agrees with the comments submitted by EEI in response to this request for comments and copied here: Comments on the Rational EEI does not support the stated rational which has led to the overly expansive scope for this data request. We question why elements far beyond those which have been proven to be vulnerable to SPOF problems are being assessed. We are concerned that the collection of such a broad range of data may be intended for use and purpose beyond any effort to satisfy Commission concerns and directives specified to Order 754. We believe this concern is justified by the collection of system data in areas where no reliability concern has been identified. We are also concerned that elements that have been known to have SPOF concerns such as auxiliary and lockout relays are not specifically considered or included. For this reason, we strongly recommend that assessments conducted under this data request be limited to those elements specifically identified as having known SPOF risks while limiting the collection of data in-line with the existing TPL standard which we believe is sufficient to ensure an adequate level of reliability. Miscellaneous Other Comments Although we recognize the urgency of getting the draft Data Request finalized and approved, we are concerned that the Industry will not have an opportunity to provide additional comments on the final version of the Data Request. Given the fluidity of this draft document, we find it unfair to encumber the Industry with such an onerous effort without allowing an adequate comment period. Issues Identified during the Webinars The question and answer sessions following the second Webinar indicated that the Table “B” set of protection system requirements may not be needed for a SPOF assessment. For example, a single trip coil that has failed may not in itself indicate a stressed |

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| system if the circuit breaker is protected with breaker failure relaying. We believe this to be correct and submit that a valid TPL standard would assess this condition. It has been noted that NERC stated in one of the Webinars that delayed clearing associated with three phase faults do not have performance requirements. We believe this to be inaccurate. TPL-004 requirement 4 states: The Planning Authority and Transmission Planner shall each demonstrate through a valid assessment that its portion of the interconnected transmission system is evaluated for the risks and consequences of a number of each of the extreme contingencies that are listed under Category D of Table I. Further, Table D states: Evaluation of these events may require joint studies with neighboring systems. |
| Group |
| SERC Protection and Control Subcommittee |
| George Pitts (TVA) and Paul Nauert (Ameren) co-chairs, Joe Spencer (SERC staff) |
| 1. In Method section, step 1, please clarify that the intent of the first bullet is to make the first cut at reducing the Table A list by those locations meeting Table B. 2. In Method section, step 1, please clarify the second bullet is to then augment the list, we suggest “Also include only transmission transformers supplying external short circuits for which through-fault protection is only provided via remote detection and clearing.” 3. Reword Method section, step 2 so that it is clear that the simulations are to be done for the bus list derived from Method section, step 1. 4. Given your ‘as built’ and 300MW of load criteria, please state that “a near-term, peak load seasonal case should be used for determinations.” 5. Allow entities to skip Method section, step 4 and go directly to the actual clearing times steps, if they believe it to be more efficient. 6. For the Table A note, only generator step-up transformers for registered generation should count as a circuit. 7. Clarify the meaning of “no common dc control circuitry” within the Table B, DC Control Circuitry attribute. 8. Footnote 13 hyperlink does not work. 9. For the system impact, are stability studies to be run at peak load or off peak? |
| 1. The RFI should take precedence over the template instructions, if they conflict. For example, ambiguity exists between ”transmission transformers” and “Step-down Transformers.” 2. The template forces much extra work by asking for redundancy attributes of each ‘circuit’ type. This is burdensome and should be omitted. The approach stated on the 1/5/2012 webinar is that once we determine one redundancy attribute at a (planning) bus is not met, we need to include that bus, and can stop our research is much more efficient and strongly preferred. |
| None |
| 1. FERC has not yet approved the Protection System definition in footnote 17, so the existing definition should be used. 2. Please add “Relay types are listed in note 13 on page 12” in footnote 18. 3. Few ‘lack of Protection System redundancy’ events have occurred in the last decade. This RFI is a significant burden and imposes a distraction of key resources at each entity. This may pose greater risk to BES reliability than these extremely rare events. The PCS recommends: a. that the deadline be extended from one to two years b. that a higher level screening criteria be utilized ( e.g. Table A could require six or more circuits rather than four or more circuits at 200kV or higher and could require eight or more circuits rather than six or more circuits at 100kV to 200kV ) |