**Name (53 Responses)**
**Organization (53 Responses)**
**Group Name (20 Responses)**
**Lead Contact (20 Responses)**
**Question 1 (72 Responses)**
**Question 1 Comments (73 Responses)**
**Question 1 (0 Responses)**
**Question 2 (68 Responses)**
**Question 2 Comments (73 Responses)**
**Question 2a (63 Responses)**
**Question 2a Comments (73 Responses)**
**Question 3 (68 Responses)**
**Question 2a Comments (73 Responses)**
**Question 3a (64 Responses)**
**Question 3a Comments (73 Responses)**
**Question 4 (69 Responses)**
**Question 4 Comments (73 Responses)**
**Question 4 (61 Responses)**
**Question 4a Comments (73 Responses)**
**Question 5 (65 Responses)**
**Question 5 Comments (73 Responses)**
**Question 5a (64 Responses)**
**Question 5a Comments (73 Responses)**
**Question 6 (48 Responses)**
**Question 6 Comments (73 Responses)**
**Question 6a (62 Responses)**
**Question 6a Comments (73 Responses)**
**Question 7 (67 Responses)**
**Question 7 Comments (73 Responses)**
**Question 7a (65 Responses)**
**Question 7a Comments (73 Responses)**
**Question 8 (68 Responses)**
**Question 8 Comments (73 Responses)**
**Question 8a (63 Responses)**
**Question 8a Comments (73 Responses)**
**Question 9 (53 Responses)**
**Question 9 Comments (73 Responses)**
**Question 10 (65 Responses)**
**Question 10 Comments (73 Responses)**
**Question 11 (49 Responses)**
**Question 11 Comments (73 Responses)**
**Question 12 (49 Responses)**
**Question 12 Comments (73 Responses)**
**Question 13 (0 Responses)**
**Question 13 Comments (73 Responses)**

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| Individual |
| David Proebstel |
| Clallam County PUD No.1 |
| No |
| CPUD is concerned that the SAR is broadly written so that “any and all aspects of the Phase 1 definition are open to discussion and possible revision.” CPUD is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that CPUD believes will be workable and strongly supports. CPUD therefore believes Phase II should be focused on the specific questions set forth in the SAR |

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| should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and "a consensus of stakeholders." As long as "consensus" is understood to be unanimous or near-unanimous support for addressing the new issue, CPUD is comfortable with supporting the SAR as written. To the extent "consensus" is interpreted to mean something less than near-unanimous support, CPUD opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide "greater clarity," we support the SDT's efforts to better define the obligations with respect to each of these issues. First, we support the SAR's intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria ("SCRC"). In CPUD's view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify "candidates for registration." SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term "non-retail generation." The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to "dispersed power resources" in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a "collector system" and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected "at a voltage of 100 kV or above"; (2) generating resources with an individual nameplate capacity of "greater than 20 MVA"; and, (3) generating resources with an aggregate plant/facility rating of "greater than 75 MVA." We emphasize that, under Section 215 of the Federal Power Act ("FPA"), a technical justification must be provided to demonstrate that is "necessary" to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines "bulk-power system" to mean "facilities and control systems necessary for operating an interconnected electric energy transmission |

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| network" and, specifically with respect to generation facilities, includes only those generators "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are "necessary" for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the "contiguous BES" debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific "facilities and control systems" at issue are "necessary for" operating the bulk interconnected transmission network and whether energy from generation facilities is "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be "contiguous" – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either "contiguous" or "non-contiguous," but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also |

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| classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| CPUD notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, CPUD opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion |

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| of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. CPUD is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
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| No |
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| Yes |
| CPUD, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200 kV rather than 100 kV should be the blackline threshold. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities, CPUD believes there is no technical justification for including facilities operating at 100-kV in the BES. CPUD therefore strongly supports the SDT’s willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC’s issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force (“BESDTF”) expended considerable effort on historical and technical analysis to determine whether a 100-kV or 200-kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council’s Bulk Electric System Definition Task Force (“BESDTF”), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend its work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF’s key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities’ resource portfolios. Transmission facilities, typically greater than 200 kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230 kV, 345 |

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| kV, and 500 kV as typical bulk transmission voltages. Facilities operating below 230 kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200 kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100 kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230 kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100 kV and 200 kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200 kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200 kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200 kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200 kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200 kV is significantly below that of the 200-300 kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200 kV, while lines operating in the range of 100-200 kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100-kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200-kV threshold with an inclusion mechanism to identify the minority of 115-kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| CPUD is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." CPUD believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. CPUD supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, CPUD is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT |

should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100 kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100 kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100 kV are not part of the BES. Transformers with no secondary terminals operating at or above 100 kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100 kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100 kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, CPUD is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. CPUD believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While CPUD strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements as depicted and identified on system one-line diagrams does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, CPUD is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, CPUD believes further improvement of

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| the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100 kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. CPUD also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, CPUD believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system. |
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| Individual |
| Ricahrd Malloy |
| Idaho Falls Power |
| No |
| We do not agree with addressing the 100kv threshold. It was our understanding that this was addressed in phase one and that the only threshold to be addressed in phase II was the generator threshold of 75 MVA. |
| No |
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| No |
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| No |
| No, because it appears that the SDT has already made the determination that the reliability of BES is |

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| dependent upon a contiguous BES and will therefore find justification to support the conclusion. Many in the industry do no hold the contiguous BES conclusion. We would propose an unbiased study into the issue. |
| No |
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| No |
| This appears to be "mission creep." Soon anything could be construed to "support." An element either is or is not necessary to the reliability of the BES. |
| No |
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| No |
| Perhaps not pursue justification but rather an evaluation of automatic interrupting devices effect upon the BES from which to evaluate their inclusion. |
| No |
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| Yes |
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| No |
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| No |
| We feel this has been addressed in phase one. |
| No |
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| Yes |
| There exist many distribution loops wherein several points on connection may allow incidental power flows but were not designed as a pathway nor are they a redundancy to the designed pathway. |
| No |
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| No |
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| No |
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| No |
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| No |
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| It is unclear as to what entities who are currently NERC registered will do should their assets meet the exclusionary criteria in the definition. Will they remain registered without auditable assets? Should they follow a path to unregister? If so, do they follow the established process? We believe this guidance or process outline is necessary as the regional entity operates out of an exceeding abundance of caution, which may cause a confusing and lengthy process. |
| Individual |
| Paul Kure |
| ReliabilityFirst Corporation |
| Yes |
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| Yes |
| I thought the original intent of the thresholds in the Compliance Registry was to reduce or limit the potential burden of compliance with the reliability standards for the smaller entities. Is this still the intent? Are the thresholds in this question intended to: a)identify which resources (or elements) |

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| impact reliable operation or b)identify the elements that are subject to the reliability standards? A case can be made that every element has some potential impact on reliable operation. However, since some elements have greater impact on reliability than others, I believe the thresholds should be used to determine those elements which should be subject to the reliability standards due to their potential for noticeable impact on reliability. The BES definition should make it clear which BPS system elements are within the scope of the NERC reliability standards (the system elements subject to NERC standards). Other BPS elements may collectively have an impact on reliability, and therefore need to be studied, but the data or information necessary to do that analysis should not be part of the standards and compliance regimes, but be collected either through the reliability assessment process or a Section 1600 data request. |
| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| No |
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| No |
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| No |
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| No |
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| Group |
| Southwest Power Pool Regional Entity |
| Emily Pennel |
| Yes |
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| No |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| No |
| Local networks should not export power. |
| No |
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| No |
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| Yes |
| SPP RE recommends technical justification review for BES users registered as LSE/DP, which have a threshold of 25 MW (see Registration Criteria). |
| No |
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| No |
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| Group |
| Hydro One Networks |
| David Curtis |
| No |
| We do not agree with the entire scope as put forward. The SAR as written suggests that Ph2 SDT should undertake the reexamination of the entire BES definition. It extends to every attribute of the definition, including the 100kV Bright-line. We believe that it is out of the scope of the Ph2 SDT to reassess and challenge the 100kV Bright-line along with every deliberation of the Ph1. The primary focus of the Ph 2 undertakings by SDT should be to ensure that the BES Definition as approved by both industry stakeholders and the NERC Board of Trustees is clear and understandable, and implemented consistently across the continent. We believe that SDT has done an excellent job in Ph1 and made an excellent decision to park 2-3 items for further assessment in Ph2. SDT has already |

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| discussed all the technical concepts in its Ph1 deliberations. Accordingly, we only support technical justification and reassessment of a select group of 2-3 items. There is no need to assess in attempt to justify each and every part/attribute of BES definition that has just been approved by the NERC BOT and filed with FERC for approval. |
| Yes |
| Yes. We also believe that technical justification process should categorize resources into one of the following categories. Elements would be categorized on a technical basis to justify the extent of applicability of the reliability standards. • Resources less than a certain threshold should be classified as BES support elements, including “must run” units and blackstart, and be only required to adhere to a small and relevant subset of reliability standards. • Resources greater than a certain threshold should be classified as BES elements and be required to adhere to all relevant reliability standards. |
| No |
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| No |
| We do not support that Ph2 should undertake the reexamination of this attribute of BES definition that has just been approved by the NERC BOT and will provide little if any value in this exercise. We believe that for most part BES will be contiguous in nature and for non contiguous unique and individual cases can be adequately addressed thru the exception process if and when a subsystem needs to be contiguous for BES reliability. |
| No |
| |
| Yes |
| We only support this with an expectation that this will be a simple and not a complex justification. The outcome of this exercise should be that BES support elements will ONLY be required to comply with a smaller subset of reliability standards. This should not put undue burden on the entities for compliance of BESS (BES Support) elements |
| No |
| |
| No |
| SDT has already discussed the technical concepts surrounding “automatic interruption devices” (AID) in its Ph1 deliberations. Further, any “tap” without AID can be designated as BES through the exception process if it has an impact on the reliability of the interconnected BES. Accordingly, there is no need to further assess this attribute of BES definition that has just been approved by the NERC BOT and filled with FERC for approval. We need to wait and learn over the next 3-5 years after current definition is implemented. |
| No |
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| No |
| We do not support that Ph2 should undertake to reexamine this attribute of BES definition that has just been approved by the NERC BOT. SDT has already discussed the technical concepts in its Ph1 deliberations. Further, Blackstart requirements are already covered in Reliability Standards regardless of whether the resource is BES or not. Cranking paths are part of the restoration process, and do not affect the reliability of the BES. There is no need to assess this attribute of BES definition that has just been approved by the NERC BOT and filed to FERC for approval. We need to wait and learn from experience over the next 3-5 years after current proposed definition is implemented. |
| No |
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| No |
| We believe that this is out of scope of SDT unless there is a direct Regulatory Order to do so. Accordingly, we do not support that Ph2 should undertake to examine the voltage threshold for BES that has just been approved by the NERC BOT and filed with FERC for approval. NERC needs to wait and learn from experience over the next 3-5 years after current proposed definition is implemented. However, the 100 kV brightline is a fundamental, but technically unsupported, assumption in the BES |

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| definition. Technical justification for the 100 kV or some higher threshold, e.g. 200kV, could be developed in Phase 2. The scope of this assessment should not be to study for elements “necessary,” but operated below 100kV threshold as they could still be brought into the BES Defintion under the Rules of Procedure (RoP) Exception Process. |
| No |
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| Yes |
| Yes, SDT should pursue this and BES definition should allow for some minimal power flow out of the local network that will NOT have an adverse impact on the reliability of the interconnected BES. |
| No |
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| No |
| |
| No |
| |
| No |
| If there are any regional or non jurisdictional variances they can/should be handled through the exception process. |
| Yes |
| This is a fundamental change that will impact many entities across the NERC foot print and require many changes to the business practices along with incremental costs for most if not all entities. |
| As mentioned above, we only support to assess and justify couple of the major items in Ph 2 at this stage. Ph 1 work has been just approved by the NERC BOT and filed with FERC. It has yet to be implemented by the industry and lessons are yet to be learned by all stakeholders including NERC. NERC needs to wait and learn from experience over the next 3-5 years after current proposed definition is implemented to further assess other attributes of the definition. As part of this process, NERC should take the opportunity to enhance the Applicapability Section of the standards to ensure that it clearly identifies the elements that the standard applies. |
| Individual |
| Frank Cain |
| LCEC |
| Yes |
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| No |
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| No |
| The term “supports” is too broad. The Team needs to identify those specific elements that “directly support” the reliability of the BES, and under what conditions. |
| No |
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| Yes |
| An automatic interrupting device may be the single element that differentiates whether the radial or LDN directly support the BES or does not support the BES. |
| No |
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| No |

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| This will force many organization that have transmission facilities that are not considered in the BES under the proposed definition to file for an exception. |
| No |
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| Yes |
| A LDN that is not intended to transfer bulk power should not have to apply for an exception simply because some power flow may occur across or through the LDN due to normal loading conditions. A LDN that does not transfer bulk power under an OATT or other Agreement should be excluded under the Bright Line definition. Neighboring systems or BA can file for an excpetion if they feel differently. |
| No |
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| No |
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| No |
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| No |
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| No |
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| Individual |
| Russ Schneider |
| Flathead Electric Cooperative, Inc. |
| No |
| some of the request for additional technical justification is unfounded, FERC direction is clear that local distribution networks should be excluded, regardless of the technical justification of their impact on the BES |
| No |
| |
| No |
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| No |
| A contiguous BES would like include elements that are excluded by statute, counter to FERC direction |
| No |
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| No |
| A technical justification alone is insufficient, the SDT must have a legal justification as well. Since Section 215(i) limits standards development to the bulk-Power system only (excluding local distribution), the SDT lacks this justification. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
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| No |
| think these would fall in under the existing definition and do not need to be called out seperately |
| No |
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| No |

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| No |
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| No |
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| No |
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| No |
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| Yes |
| “Non-retail” generation needs to be defined. Many commenters during Phase I expressed this need, but the SDT responded “Non-retail generation is a widely used and understood term and is not defined here. “ With so many comments it is clear the term is not widely understood, and we wish to ensure the CEA uses the same definition we do. We note that in the same consideration of comments document, the SDT did in fact provide a reasonable definition. We have no reason to think that definitions provided in such a document will be considered at all during an audit. The definition should reside in the BES definition document, or separately in the NERC Glossary. We continue to advocate that the flow through the document needs to be addressed. While some some inclusions list further exclusions (I1 points to E1 and E3), there is no clear general rule on how to classify an element that meets both an inclusion and an exclusion. An I5 capacitor on an E1 radial line for example, or capacitor that meets both I5 and E5. Until this is clearly specified, there will continue to be disagreements between the registered entities and the compliance enforcement authorities. |
| No |
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| No |
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| I think the SDT should keep the eye on the prize here, which is to revise the BES definition to make clear that local distribution is not BES. Since Section 215(i) limits standards development to the bulk-Power system only and specificially excludes local distribution. |
| Individual |
| John Bee |
| Exelon |
| Yes |
| What is meant by “appropriate ‘point of demarcation’”? Between Generation and Transmission the point of demarcation is always contractual and is typically based on asset ownership. Exelon uses the FERC 7 Factor Test as defined in Order No. 888 to define the demarcation between Transmission and Distribution. |
| Yes |
| |
| No |
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| Yes |
| Exelon agrees that the SDT should pursue technical justification of this issue but does not agree that there is necessarily an assumption that there is a reliability benefit of a contiguous BES. |
| No |
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| Yes |
| Exelon agrees as long as the technical justification includes the examination of appropriate thresholds. |
| No |
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| No |
| To the extent that Section 215 of the Federal Power Act excludes facilities used in the local distribution of energy, these facilities are not under FERC or NERC's jurisdiction and therefore should not be included in the BES definition. |
| No |
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| No |
| To the extent that Section 215 of the Federal Power Act excludes facilities used in the local distribution of energy, these facilities are not under FERC or NERC's jurisdiction and therefore should not be included in the BES definition. |
| No |
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| Yes |
| Exelon believes that the technical justification needs to include an evaluation of bright line for each Interconnection. |
| No |
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| Yes |
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| No |
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| No |
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| No |
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| Yes |
| Refer to #7. |
| No |
| A full analysis depends on the results of Phase 2. |
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| Individual |
| Terri Pyle |
| Oklahoma Gas & Electric |
| Yes |
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| Yes |
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| No |
| Would the SDT be open to developing a set of criteria that would cause reliability issues on the BES; i.e., actual impact vs a specific MW/MVA threshold? |
| Yes |
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| No |
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| Yes |
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| No |
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| Yes |

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| No |
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| No |
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| No |
| While we believe the Cranking Path is an important part of the system, we don't believe it is realistic or necessary to apply all standards to < 100 kV elements due to inclusion in Cranking Path of a Blackstart Resource. We suggest identifying specific standard requirements that are important to those < 100 kV elements and making only those applicable. |
| No |
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| No |
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| Yes |
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| No |
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| No |
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| No |
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| No |
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| No |
| We are not currently aware of a business practice that will need to be modified; however, that could change based on further development of Phase 2 of the BES Definition. |
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| Individual |
| Greg Rowland |
| Duke Energy |
| No |
| See comments below on specific aspects of the proposed scope. |
| Yes |
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| No |
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| Yes |
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| No |
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| No |
| "Supports the reliable operation of the BES" is impossibly broad for the drafting team to pursue. |
| No |
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| Yes |
| We believe inclusion of properly coordinated interrupting devices should be a condition for exclusions E1 and E3. |
| No |

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| Improperly cleared faults on radial systems and Local Networks are problems that must be addressed. |
| No |
| Utilization of Cranking Paths is post-blackout, and Cranking Paths are already appropriately addressed in EOP and CIP Reliability Standards. There's no point in including Cranking Paths in the BES definition. |
| No |
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| No |
| Raising to a higher voltage level would be "lowering the bar" on reliability. Going to a lower voltage level would increase costs without proportional reliability benefits. Therefore there is no benefit in commiting the resources to pursue a technical justification for retaining the current level. |
| No |
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| Yes |
| However this should be a low priority for the Standard Drafting Team. |
| No |
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| No |
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| No |
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| No |
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| No |
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| Group |
| Southwest Power Pool Standards Development Team |
| Jonathan Hayes |
| Yes |
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| Yes |
| |
| No |
| Another approach might be to look at the impact rather than a MW threshold and set criteria for those units that would cause reliability issues on the system. |
| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
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| No |
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| No |

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| We don’t disagree that the cranking path is an important part of the system but feel that exposing sub 100KV elements to the many other standards is excessive. This could turn a distribution provider into a transmission operator. We would suggest that the drafting team if they do move forward that they would clarify a certain group of standards that would apply to these specific sub 100KV elements only. |
| No |
| |
| No |
| We thought that the current definition was set at 100KV and would support technical justification for a bright line voltage level higher than the current 100KV. |
| No |
| |
| Yes |
| |
| No |
| |
| No |
| |
| No |
| |
| No |
| There might be some that come out of the final phase two definition. But we aren’t aware of any at this time. |
| No |
| Right now our answer would have to be no, but that could change as this phase develops. |
| |
| Group |
| Northeast Power Coordinating Council |
| Guy Zito |
| No |
| The primary focus of the SDT should be to ensure that the BES Definition as approved by both industry stakeholders and the NERC Board of Trustees is clear and understandable, and implemented consistently across the continent. To that end: • Add the following scope element: Determine if there is a technical justification to support the 300 kV limitation on Local Network elements. This bright line limitation on elements which may be part of a Local Network lacks any technical justification and therefore should be included in the Phase 2 SAR. • Revise the bullet “Determine if there is a technical justification to support the assumption that there is a reliability benefit of a contiguous BES” to: “Determine if there is a technical justification to include in the BES definition whether the BES should be contiguous.” It has not been assumed that the BES must be contiguous. • Delete the following scope element: “Determine if there is a technical justification to support the inclusion of Cranking Paths and Blackstart Resources” because it was addressed by the Phase 1 SDT. “Cranking Path” is already a defined term in the NERC Glossary and the requirement for Transmission Operators to document Cranking Paths is already stipulated in EOP-005. • To establish Real and Reactive Power bright lines, a fixed ‘bright line’ approach fails to consider relative impact. For example, a 20 MVA generation resource within a 200 MW radial system may represent a significant reliability concern. However, that same 20 MVA generator within a 10,000 MW interconnected system may not be as significant because of the availability of resources to compensate for that 20MVA generator. Any BES Definition which establishes a fixed MVA threshold cannot consider the relative impacts on reliability . Any fixed Real and Reactive Resource bright line thresholds established using the most restrictive case contintent-wide will inappropriately impose excess reliability cost for little or no reliability benefit on systems everywhere small unit operation is not impactful or necessary. Propose the following language for Phase 2 Real and Reactive Resource bright line thresholds: “Develop a technical justification to set the appropriate threshold for Real and Reactive Resources used in the operation of |

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| the Bulk Electric System (BES). The BES Real and Reactive Resource thresholds may either be fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified.” • The Phase 1 BES SDT did not define the term “local distribution facilities”, although the core BES definition excludes such facilities. Add to the SAR: Develop a technical basis and definition for the term local distribution facilities. Due consideration should be given to using the precedents identified in FERC Order 743-A. • The Phase 1 BES SDT developed Technical Principles for the exemption of facilities from the BES. These Technical Principles are to be employed as a simplified check list of exemption factors for use by Regional review panels. A renewed effort should be made in Phase 2 to strengthen the Technical Principles. The objective should be to develop the FERC-directed “clear, objective, transparent, and uniformly applicable criteria for exemption of facilities”. Suggest adding the following: “Develop technical principles for the “clear, objective, transparent, and uniformly applicable criteria for exemption of facilities” for removing from the definition jurisdictional facilities not ‘necessary’ for the reliable operation of the Bulk Electric System.” |
| Yes |
| Refer to the response to Question 1. Resources greater than a certain threshold should be classified as BES elements and be required to adhere to all relevant reliability standards. The threshold need not be a fixed MVA level, but could be either fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified. Propose the following language for Phase 2 Real and Reactive Resource bright line thresholds: “Develop a technical justification to set the appropriate threshold for Real and Reactive Resources used in the operation of the Bulk Electric System (BES). The BES Real and Reactive Resource thresholds may either be fixed (as used today), per unit, or on a system percentage basis, as may be appropriate and technically justified.” |
| No |
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| Yes |
| Refer to the response to Question 1 regarding the contiguous BES. This should be investigated by the Phase 2 team. The “contiguous” issue was never resolved by Phase 1 team. This issue can be addressed for unique cases through the exception process. |
| No |
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| No |
| This should be assigned to a different drafting team under a separate SAR. It should be limited to a simple and not a complex justification with an idea that BES support elements will only be required to comply with a smaller subset of reliability standards. This should not put undue burden of compliance for BES elements on the entities. Equipment that supports the reliable operation of the BES must be defined. “Support” must also be defined for its use in this context. Technical justification should analyze the facts, and then a determination made whether it does or does not support being included in the BES definition. The term “associated equipment” contained in the NERC Glossary of Terms Used In NERC Reliability Standards definition of “Transmission” either should be removed from that definition or should be separately defined. “Associated equipment” should be limited to a simple list of elements, such as relays and switches connected to BES feeders, and should not require use of a complex justification. The definition should be developed with the idea that BES support elements may only be required to comply with a subset of requirements specifically identified in applicable reliability standards. This definition should not put undue burden of compliance for BES elements on the entities. This is an alternate approach that supports the reliability language. |
| No |
| |
| Yes |
| Technical justification for this was not provided in Phase 1, and needs to be included in Phase 2. It should be addressed that an element which is excluded from the BES should be able to separate itself from the BES in the case of a fault on the non-BES element. |
| No |
| Discussed by the SDT in its Phase 1 deliberations. There is no existing technical justification available. |
| No |

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| Phase 2 should not undertake an examination of every attribute of the BES definition which has already been approved by the industry and the NERC Board of Trustees and filed with FERC. Blackstart requirements exist regardless if they are BES or not and are covered in the Reliability Standards. The SDT has already discussed the technical concepts in its Phase 1 deliberations. Refer to the response to Question1. Cranking paths are part of the restoration process, and do not affect the reliability of the BES. |
| No |
| |
| Yes |
| The 100 kV brightline is a fundamental, but technically unsupported, assumption in the BES definition. Technical justification for the 100 kV or some higher threshold, e.g. 200kV, should be developed in Phase 2. Elements "necessary," but operated below this technically justified threshold could still be brought into the BES Defintion under the Rules of Procedure (RoP) Exception Process. |
| No |
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| Yes |
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| No |
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| Yes |
| There needs to be a technical justification and a threshold for the inclusion of "dispersed power producing resources" (for example wind, and solar). |
| Yes |
| Refer to the responses to all the above questions. The SDT needs to develop a "BES Definition Application Guide" to ensure that the BES Definition is implemented consistently across the continent. The "BES Definition Application Guide" would be most helpful to industry if it included both one-line diagrams and explanations with examples for each inclusion and exclusion. Regarding specific clarifications for the Phase 1 Definition: • Exclusion E2 depends on whether contractual or regulatory "services are provided to the generating unit… or to the retail Load." The SDT should provide specific examples for E2 part (ii) in which facilities would or would not be excluded. Alternatively, condition (ii) could be deleted. • Both Exclusions E2 and E3 are flow-based exclusions and depend on analysis rather than system configuration. The assumptions and conditions for this analysis are dependent on the BES classification. Do these flow specifications apply to all critical system conditions, such as load, dispatch, transfers, and do they apply to both "normal" and "post-contingency" conditions? If so, which contingencies need to be assessed for this analysis – for example, P0 through P7 events in TPL-001-2? • Exclusion E1 needs to be reworded for clarification. Exclusion E1 is labeled "radial systems". Is this intended to apply to a single transmission line from a substation bus to another substation (with no other connections of 100 kV or higher)? If there were a parallel transmission line from that same bus to that other substation would those lines not be considered "radial"? Are transmission line taps considered "radial systems"? Annotated one-line diagram examples would easily clarify this exclusion. • Does the "Note" in Exclusion E1 that a "normally open switching device… does not affect this exclusion;" mean that the device should be considered not to exist (as if permanently open), or that the device status should be disregarded (do not assume it will be open)? • Inclusion I4 depends on the term "connected at a common point"-- this needs to be defined or better explained. For example, is this considered to be the Collector Substation feeder connection low-voltage bus only, or also the high-voltage bus on the high side of the collector transformer at the Collector Substation? If it is the former, it will exclude all of the wind interconnections of all sizes presently in the northeast United States (feeder voltages can be 34.5 kV for wind farms of hundreds of MW capacity). |
| No |
| As this project moves forward there may be issues that to be resolved will require regional variances. At that time industry must be given the opportunity to provide comments. |
| No |
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| The primary goal of Phase 2 must be to develop guidance for the new BES Definition. Any technical |

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| justification efforts should not detract from the guidance effort and must be consistent with the FERC Orders on the BES Definition. There is a risk that technical analyses to justify inclusions and exclusions of elements in the BES Definition may be generalized to a larger set of conditions, when the analyses apply only to a set of specific situations or system conditions. System behavior depends on many factors, many of which are not standardized for the entire industry. An item that should be added to the SAR project and addressed is the necessity to define what is meant by the phrase "necessary for the reliable operation of the interconnected transmission network". Some discussion to establish a reliability matrix must precede other discussions concerning items included in the SAR. If the vast majority of Elements are indeed useful to reliability, not all should be considered as necessary. Stability, reliability and grid integrity issues have to be distinguished from service continuity issues. Elements that contribute to the reliability of the BES have to be distinguished from those that contribute to the reliability of local load (service continuity). Referring to NERC's Reliability Principles, Reliability Objectives (draft), or to the Concept of Adequate Level of Reliability are resources that would be helpful. The analyses used to make technical justifications to be considered by the Drafting Team in potential revision of the Standard should be pub,ished and be made available to the stakeholders for review. The subject matter expertise must be made available by either expanding the Drafting Team or through delegation of technical study to the appropriate NERC groups or other existing Drafting Teams. The Standards Committee could commission another Drafting Team as necessary for portions of the work, and the Drafting Team assign a “sub-team” as well, a RFP could be issued. Suggest that the Operating and Planning Committees be engaged as necessary during the comment periods to provide specialized subject matter expertise. There is concern regarding the coordination of the timing of the implementation of Phases 1 and 2. The BES Definition Application Guide mentioned in the response to Question 10 that should be developed should be presented to industry for review and comment, and the consideration to have it balloted should be weighed. It would be needed by industry before Phase 2, in any format, is balloted. |
| Individual |
| Joe Jarvis |
| Blachly-Lane Electric Cooperative |
| No |
| BLEC is concerned that the SAR is broadly written so that “any and all aspects of the Phase 1 definition are open to discussion and possible revision.” BLEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that BLEC believes will be workable and strongly supports. BLEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and “a consensus of stakeholders.” As long as “consensus” is understood to be unanimous or near-unanimous support for addressing the new issue, BLEC is comfortable with supporting the SAR as written. To the extent “consensus” is interpreted to mean something less than near-unanimous support, BLEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide “greater clarity,” we support the SDT’s efforts to better define the obligations with respect to each of these issues. First, we support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In BLEC’s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify “candidates for registration.” SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the |

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| validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term “non-retail generation.” The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to “dispersed power resources” in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a “collector system” and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |

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| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, |

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| there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| BLEC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, BLEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. BLEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
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| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
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| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| BLEC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the |

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| WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, BLEC believes there is no technical justification for including facilities operating at 100kV in the BES. BLEC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in |

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| the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| BLEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” BLEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. BLEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, BLEC is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, BLEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. BLEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and |

confusing. Second, the "Note" at the end of the exclusion states that "a normally open switching device between radial systems" will not serve to disqualify the Radial from exclusion under Exclusion 1. While BLEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase "as depicted and identified on system one-line diagrams" from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, BLEC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, BLEC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. BLEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, BLEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely

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| eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Dave Markham |
| Central Electric Cooperative |
| No |
| CEC is concerned that the SAR is broadly written so that “any and all aspects of the Phase 1 definition are open to discussion and possible revision.” CEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that CEC believes will be workable and strongly supports. CEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and “a consensus of stakeholders.” As long as “consensus” is understood to be unanimous or near-unanimous support for addressing the new issue, CEC is comfortable with supporting the SAR as written. To the extent “consensus” is interpreted to mean something less than near-unanimous support, CEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide “greater clarity,” we support the SDT’s efforts to better define the obligations with respect to each of these issues. First, we support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In CEC’s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify “candidates for registration.” SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term “non-retail generation.” The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to “dispersed power resources” in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a “collector system” and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems |

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| for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk |

system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could

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| inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| CEC notes that there are significant differences between the question presented in the "Scope" statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: "Determine if there is a technical justification for the equipment which "supports" the reliable operation of the BES but is installed on the distribution system." If the question is formulated in this way, CEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES "facilities used in the local distribution of electric power." 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for "including in the BES definition the equipment which 'supports' the reliable operation of the BES." In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. CEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are "necessary for" operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are "necessary for" reliable operation of the BES, not whether they "support" operation of the BES. To the extent the question contemplates classifying facilities that are not "necessary for" operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT's task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT's mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT's limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they |

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| must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| CEC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, CEC believes there is no technical justification for including facilities operating at 100kV in the BES. CEC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis |

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| already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| CEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." CEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. CEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |

As reflected in our response to Question 1, CEC is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, CEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. CEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While CEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, CEC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could

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| cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, CEC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. CEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, CEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Dave Hagen |
| Clearwater Power Company |
| No |
| CPC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� CPC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the |

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| reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that CPC believes will be workable and strongly supports. CPC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, CPC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, CPC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In CPC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition. |

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| as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected "at a voltage of 100kV or above"; (2) generating resources with an individual nameplate capacity of "greater than 20 MVA"; and, (3) generating resources with an aggregate plant/facility rating of "greater than 75 MVA." We emphasize that, under Section 215 of the Federal Power Act ("FPA"), a technical justification must be provided to demonstrate that is "necessary" to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines "bulk-power system" to mean "facilities and control systems necessary for operating an interconnected electric energy transmission network" and, specifically with respect to generation facilities, includes only those generators "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are "necessary" for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the "contiguous BES" debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific "facilities and control systems" at issue are "necessary for" operating the bulk interconnected transmission network and whether energy from generation facilities is "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be "contiguous" – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either "contiguous" or "non-contiguous," but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as |

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| distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |

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| No |
| CPC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, CPC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. CPC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase |

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| NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| CPC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, CPC believes there is no technical justification for including facilities operating at 100kV in the BES. CPC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than |

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| the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| CPC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." CPC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. CPC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, CPC is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word "and" ("the primary and secondary terminals"). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT's |

intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, CPC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. CPC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While CPC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, CPC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, CPC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. CPC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, CPC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system

Individual

Roman Gillen

Consumers Power Inc.

No

CPI is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� CPI is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that CPI believes will be workable and strongly supports. CPI therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, CPI is comfortable with supporting the SAR as written. To the extent �consensus� is

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| interpreted to mean something less than near-unanimous support, CPI opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In CPI�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific |

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| thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of |

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| the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| CPI notes that there are significant differences between the question presented in the "Scope" statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: "Determine if there is a technical justification for the equipment which "supports" the reliable operation of the BES but is installed on the distribution system." If the question is formulated in this way, CPI opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES "facilities used in the local distribution of electric power." 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for "including in the BES definition the equipment which 'supports' the reliable |

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| operation of the BES." In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. CPI is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are "necessary for" operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are "necessary for" reliable operation of the BES, not whether they "support" operation of the BES. To the extent the question contemplates classifying facilities that are not "necessary for" operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT's task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT's mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT's limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed |

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| in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| CPI, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, CPI believes there is no technical justification for including facilities operating at 100kV in the BES. CPI therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical |

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| analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 “Transfer Paths,” the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: “As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines.” In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| CPI is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” CPI believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. CPI supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, CPI is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial |

System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, CPI is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. CPI believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While CPI strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, CPI is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, CPI believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. CPI also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting

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| power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, CPI believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Roger Meader |
| Coos-Curry Electric Cooperative |
| No |
| CCEC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� CCEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that CCEC believes will be workable and strongly supports. CCEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, CCEC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, CCEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In CCEC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. |

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| We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely |

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| that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, |

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| there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| CCEC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, CCEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. CCEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s |

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| limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| CCEC, and many other entities, especially (but not exclusively) from the WECC region, have from the |

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| beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, CCEC believes there is no technical justification for including facilities operating at 100kV in the BES. CCEC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the |

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| available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| CCEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” CCEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. CCEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, CCEC is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, CCEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. CCEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices |

from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While CCEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, CCEC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, CCEC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. CCEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the

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| system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, CCEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Bryan Case |
| Fall River Electric Cooperative |
| No |
| FALL is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� FALL is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that FALL believes will be workable and strongly supports. FALL therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, FALL is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, FALL opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In FALL�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in |

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| certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the |

specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the

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| FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| FALL notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, FALL opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. FALL is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at |

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| one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System which excludes fuses. We don’t see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP’s level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we’ve stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| FALL, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, FALL believes there is no technical justification for including facilities operating at 100kV in the BES. FALL therefore strongly supports the SDT’s willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
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| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| FALL is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only |

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| into the LN.” FALL believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. FALL supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, FALL is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, FALL is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. FALL believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While FALL strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether |

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| switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, FALL is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, FALL believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. FALL also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, FALL believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Rick Crinklaw |
| Lane Electric Cooperative |
| No |
| LEC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� LEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that LEC believes will be workable and strongly supports. LEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, LEC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, LEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In LEC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance |

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| obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of |

questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased

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| compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| LEC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, LEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. LEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like |

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| the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System which excludes fuses. We don’t see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP’s level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we’ve stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| LEC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, LEC believes there is no technical justification for including facilities operating at 100kV in the BES. LEC therefore strongly supports the SDT’s willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC’s issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force (“BESDTF”) expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council’s Bulk Electric System Definition Task Force (“BESDTF”), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF’s key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities’ |

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| resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| LEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." LEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. LEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, LEC is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions |

decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, LEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. LEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While LEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, LEC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because

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| behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, LEC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. LEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, LEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Annie Terracciano |
| Northern Lights Inc. |
| No |
| NLI is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� NLI is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that NLI believes will be workable and strongly supports. NLI therefore |

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| believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, NLI is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, NLI opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In NLI�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �colNLItor system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation |

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| resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of |

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| the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |

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| NLI notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, NLI opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. NLI is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System which excludes fuses. We don’t see TOs rushing to re- |

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| coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| NLI, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, NLI believes there is no technical justification for including facilities operating at 100kV in the BES. NLI therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In |

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| other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| NLI is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." NLI believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. NLI supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, NLI is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word "and" ("the primary and secondary terminals"). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT's intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: "Transformers |

with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES." This language will help ensure that there is no controversy over whether the SDT's use of the word "and" in the phrase "the primary and at least one secondary terminals" was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing ". . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above" so that the Inclusion covers transformers with terminals "connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above." 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase ". . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2." This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, NLI is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. NLI believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term "transmission Elements" in the initial paragraph should be changed to "Elements." Radial systems are not transmission systems and including the word "transmission" in the Radial System exclusion is therefore unnecessary and confusing. Second, the "Note" at the end of the exclusion states that "a normally open switching device between radial systems" will not serve to disqualify the Radial from exclusion under Exclusion 1. While NLI strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase "as depicted and identified on system one-line diagrams" from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, NLI is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, NLI believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the

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| core definition, and there is no reason to carry the term through in the Exclusions. NLI also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, NLI believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Aleka Scott |
| Pacific Northwest Generating Cooperative |
| No |
| PNGC is concerned that the SAR is broadly written so that "any and all aspects of the Phase 1 definition are open to discussion and possible revision." PNGC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that PNGC believes will be workable and strongly supports. PNGC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and "a consensus of stakeholders." As long as "consensus" is understood to be unanimous or near-unanimous support for addressing the new issue, PNGC is comfortable with supporting the SAR as written. To the extent "consensus" is interpreted to mean something less than near-unanimous support, PNGC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the |

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| SAR proposed to provide “greater clarity,” we support the SDT’s efforts to better define the obligations with respect to each of these issues. First, we support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In PNGC’s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify “candidates for registration.” SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term “non-retail generation.” The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to “dispersed power resources” in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a “collector system” and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary |

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| depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
| No |
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| No |
| We believe the "contiguous BES" debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific "facilities and control systems" at issue are "necessary for" operating the bulk interconnected transmission network and whether energy from generation facilities is "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be "contiguous" – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either "contiguous" or "non-contiguous," but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id |

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| Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| PNGC notes that there are significant differences between the question presented in the "Scope" statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: "Determine if there is a technical justification for the equipment which "supports" the reliable operation of the BES but is installed on the distribution system." If the question is formulated in this way, PNGC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES "facilities used in the local distribution of electric power." 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for "including in the BES definition the equipment which 'supports' the reliable operation of the BES." In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. PNGC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are "necessary for" operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are "necessary for" reliable operation of the BES, not whether they "support" operation of the BES. To the extent the question contemplates classifying facilities that are not "necessary for" operation of the |

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| bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT's task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT's mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT's limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| PNGC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, PNGC believes there is no technical justification for including facilities operating at 100kV in the BES. PNGC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like |

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| the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: “As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines.” In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| PNGC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” PNGC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. PNGC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, PNGC is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, PNGC is concerned that there is no threshold specified for Reactive Power devices that would be considered |

part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. PNGC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term "transmission Elements" in the initial paragraph should be changed to "Elements." Radial systems are not transmission systems and including the word "transmission" in the Radial System exclusion is therefore unnecessary and confusing. Second, the "Note" at the end of the exclusion states that "a normally open switching device between radial systems" will not serve to disqualify the Radial from exclusion under Exclusion 1. While PNGC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase "as depicted and identified on system one-line diagrams" from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, PNGC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, PNGC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. PNGC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while

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| power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, PNGC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Heber Carpenter |
| Raft River Rural Electric Cooperative |
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| RAFT is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� RAFT is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that RAFT believes will be workable and strongly supports. RAFT therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, RAFT is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, RAFT opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In RAFT�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale |

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| generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system |

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| substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| RAFT notes that there are significant differences between the question presented in the "Scope" statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: "Determine if there is a technical justification for the equipment which "supports" the reliable operation of the BES but is installed on the distribution system." If the question is formulated in this way, RAFT opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES "facilities used in the local distribution of electric power." 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for "including in the BES definition the equipment which 'supports' the reliable operation of the BES." In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. RAFT is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are "necessary for" operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are "necessary for" reliable operation of the BES, not whether they "support" operation of the BES. To the extent the question contemplates classifying facilities that are not "necessary for" operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT's task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT's mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT's limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |

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| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| RAFT, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, RAFT believes there is no technical justification for including facilities operating at 100kV in the BES. RAFT therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our |

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| response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |

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| Yes |
| RAFT is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” RAFT believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. RAFT supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, RAFT is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, RAFT is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. RAFT believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While RAFT strongly supports the note in concept, we suggest including the relevant language in a |

separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, RAFT is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, RAFT believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. RAFT also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, RAFT believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has

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| not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Steve Eldrige |
| Umatilla Electric Cooperative |
| No |
| UEC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� UEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that UEC believes will be workable and strongly supports. UEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, UEC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, UEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In UEC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be |

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| established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions |

is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators "would do little, if anything, to improve the reliability of the Bulk Electric System," especially "when compared to the operation of the equipment that actually produces electricity – the generation equipment itself." Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation's distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is "necessary for" reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to

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| standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| UEC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, UEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. UEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on |

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| the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| UEC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, UEC believes there is no technical justification for including facilities operating at 100kV in the BES. UEC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase |

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| II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| UEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." UEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. UEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
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| Yes |
| As reflected in our response to Question 1, UEC is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, UEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. UEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While UEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, UEC is concerned that Exclusion |

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| 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, UEC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. UEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, UEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Marc Farmer |
| West Oregon Electric Cooperative |
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WOEC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� WOEC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that WOEC believes will be workable and strongly supports. WOEC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, WOEC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, WOEC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In WOEC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis.

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| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is |

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| “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010- |

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| 07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| WOEC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, WOEC opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. WOEC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. |

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| Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System which excludes fuses. We don’t see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP’s level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we’ve stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| WOEC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, WOEC believes there is no technical justification for including facilities operating at 100kV in the BES. WOEC therefore strongly supports the SDT’s willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC’s issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force (“BESDTF”) expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council’s Bulk Electric System Definition Task Force (“BESDTF”), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF’s key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities’ resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub- |

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| transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| WOEC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." WOEC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. WOEC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, WOEC is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100kV or higher. As we understand it, the BES intends to include |

transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above.” 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, WOEC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. WOEC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While WOEC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, WOEC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, WOEC believes further improvement of the language could be achieved with additional

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| modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. WOEC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN “transfers energy originating outside the LN for delivery through the LN to loads located within the LN.” Finally, WOEC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Margaret Ryan |
| Pacific Northwest Generating Cooperative |
| No |
| PNGC is concerned that the SAR is broadly written so that �any and all aspects of the Phase 1 definition are open to discussion and possible revision.� PNGC is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that PNGC believes will be workable and strongly supports. PNGC therefore believes Phase II should be focused on the specific questions set forth in the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT |

may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the Team and �a consensus of stakeholders.� As long as �consensus� is understood to be unanimous or near-unanimous support for addressing the new issue, PNGC is comfortable with supporting the SAR as written. To the extent �consensus� is interpreted to mean something less than near-unanimous support, PNGC opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide �greater clarity,� we support the SDT�s efforts to better define the obligations with respect to each of these issues. First, we support the SAR�s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (�SCRC�). In PNGC�s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify �candidates for registration.� SCRC at p.3, � 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term �non-retail generation.� The meaning of this term is not clear � it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. For similar reasons, we support an effort to further clarify the reference to �dispersed power resources� in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a �collector system� and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis.

Yes

We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these

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| thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from variations in demand of the distribution system arising from load variation. |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by included only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be |

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| classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that BES generators are connected to the bulk transmission facilities that are also classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| PNGC notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which “supports” the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, PNGC opposes including this question |

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| in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824[CHECK], but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. PNGC is nonetheless concerned that they question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. |
| No |
| The requirement to have automatic interrupting devices at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. For example, please consider a loop fed TO owned BES line that is tapped with a DP owned radial line that can be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100kV. The normal protection used on looped lines is distance (impedance) protection. Two or more zones are used, the first generally has no intentional delay and is set to slightly under-reach the remote end bus. Zone 2 is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an automatic fault interrupting device (AFID) at the tap point, and a DP wishes to avoid having their tap line classified as BES they must install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section settings depends on the next, the process will probably continue until the next DP announces their AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System which excludes fuses. We don’t see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP’s level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID protected radial line and the hard tapped version that much less. The |

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| best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. We have spoken in generalities here, since there are probably exceptions to what we've stated above. If any entity can show the radial line or Local Network does impact the BES, they can seek an inclusion through the exception process. |
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| No |
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| Yes |
| PNGC, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200kV rather than 100kV should be the blackline threshold. This is because most 115kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115kV facilities, PNGC believes there is no technical justification for including facilities operating at 100kV in the BES. PNGC therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100kV or 200kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend this work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230kV, 345kV, and 500kV as typical bulk transmission voltages. Facilities operating below 230kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local-area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between |

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| 100kV and 200kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200kV is significantly below that of the 200-300kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200kV, while lines operating in the range of 100-200kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200kV threshold with an inclusion mechanism to identify the minority of 115kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| PNGC is concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." PNGC believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, "the LN does not transfer energy originating outside the LN for delivery through the LN"), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in small amounts or only during unusual contingencies. PNGC supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. |
| No |
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| Yes |
| As reflected in our response to Question 1, PNGC is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. Our specific suggestions for clarification are: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100kV or above, which is why the definition uses the word "and" ("the primary and secondary terminals"). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT's intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: "Transformers with primary terminals that operate at or below 100kV are not part of the BES. Transformers with no secondary terminals operating at or above 100kV are also excluded from the BES." This language will help ensure that there is no controversy over whether the SDT's use of the word "and" in the phrase "the primary and at least one secondary terminals" was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by |

changing ". . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100kV or above" so that the Inclusion covers transformers with terminals "connected at a voltage of 100kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100kV or above." 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase ". . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2." This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, PNGC is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. PNGC believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term "transmission Elements" in the initial paragraph should be changed to "Elements." Radial systems are not transmission systems and including the word "transmission" in the Radial System exclusion is therefore unnecessary and confusing. Second, the "Note" at the end of the exclusion states that "a normally open switching device between radial systems" will not serve to disqualify the Radial from exclusion under Exclusion 1. While PNGC strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase "as depicted and identified on system one-line diagrams" from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, PNGC is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network ("LN") exclusion, Exclusion E3, PNGC believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a "group of contiguous transmission Elements operated at or above 100kV" the starting point for identifying a LN would be improved by deleting the term "transmission" from this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. PNGC also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on

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| subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, PNGC believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Group |
| Pepco Holdings Inc & Affiliates |
| David Thorne |
| Yes |
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| Yes |
| Without a technical justification, the thresholds selected are arbitrary and may not necessarily reflect the true impact, or lack thereof, to the reliability of the BES. |
| No |
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| No |
| Assessing the reliability benefit of a contiguous BES seems to go beyond the intended scope of providing a BES definition. |
| No |
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| No |
| In the bulleted list of project scope items on page 2 of this unofficial comment form, this issue was worded as "Determine if there is a technical justification for the equipment which supports the reliable operation of the BES but is installed on the distribution system." The phrase "but installed on the distribution system" was omitted from this question. We do not agree that distribution system equipment should be included as part of the BES. |
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| No |
| In the Phase I development of the BES definition the qualifying term “and designated black-start Cranking Paths…regardless of voltage” was eliminated from Inclusion I3. This seemed a reasonable approach, which was supported by the majority of balloters. In the existing BES definition, a Local Network (LN) is defined as “a group of contiguous transmission elements operated above 100kV but less than 300kV that distribute power to load rather than transfer power across the interconnected system”. The LN would be considered part of the BES if the LN and its underlying elements include generation resources identified in Inclusion I3. If that were the case, this language would make the LN part of the BES, but not its underlying elements operating below 100kV that actually connect to the black start units (since the underlying elements operating below 100kV are not part of the definition of a local network, or part of the unmodified definition of the BES). In other words, black start cranking paths operating below 100kV, which are downstream of a LN, are excluded from the BES definition. This is consistent with the approved approach. Similarly, a radial system that consists of “a group of contiguous transmission elements that emanate from a single point of connection of 100kV or higher”, could not be excluded from being part of the BES if it includes generation resources identified in Inclusion I3. However, the BES definition includes only transmission elements operated at 100kV or higher, or real or reactive power sources connected at 100kV or higher, unless modified by the list of inclusions or exclusions. Since transmission black start cranking paths operated below 100kV are not part of the main BES definition, or any of the inclusions, they cannot be considered part of the BES. This also seems consistent with the approved approach. As such, it appears that the reference to I3 in Exclusions E1b, E1c, and E3a is intended to only draw those facilities operated at 100kV and above, which have black start units connected somewhere downstream, into being part of the BES. If that is the case, then why should the 100kV portion of the cranking path be any more important than the sub 100kV cranking paths? Since the SDT eliminated the reference to black start cranking paths in Inclusion I3, we would suggest the SDT consider eliminating the reference to I3 in criteria E1b, E1c, and E3a. Limits on connected generation in these exclusions should only be constrained by the 75MVA generation limit. Furthermore, if the above interpretation of exclusions E1b, E1c, and E3a (i.e., only 100kV and above contiguous transmission facilities and 100kV and above cranking paths are in scope) is incorrect, then the language in the BES definition should be re-visited in order to add clarity. |
| No |
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| Yes |
| Having a technical basis for the selection of what facilities are included in the BES is appropriate and necessary in order to justify the selection, and eliminate any appearance that the decision was arbitrary in nature. For example, the Transmission Relay Loadability Standard identifies a very specific set of criteria (PRC-023 - Attachment B) with which the Planning Coordinator is to evaluate 100 – 200kV facilities to assess whether they need to comply with PRC-023 relay loadability criteria. When one Planning Coordinator completed this review it was found that only a small percentage of 100 – 200kV facilities were identified. Of course these results could vary from Region to Region. Transmission systems with multiple voltage levels above 200kV rely less on the underlying 100 – 200kV systems for support of the interconnected bulk power system. Employing a set of technical criteria, which can be used to evaluate the importance of an element to the reliability of the bulk power system, ensures that all necessary elements are included, while excluding many others that would have unnecessarily been included. |
| Yes |
| In addition to the work that was done by the SDT during the development of Attachment B of PRC-023, there was considerable work done by the various Regions when they were developing their original Regional BES definitions. |
| Yes |
| A local network, supplied from multiple points within the interconnected transmission network, is essentially operating in parallel with the interconnected network. As such, depending on system contingencies, there may be small periods of time when there is a minimal power flow transferred |

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| across this local network. This is an unintended consequence of operating in parallel. The power transfer is minimal, constrained by the high impedance of the parallel path, and is not intended to be used to support the reliability of the BES. Nevertheless, based on the current definition such characteristics as described above would make this form of local network part of the BES, even though it would have little to no impact on the reliability of the interconnected bulk power system. |
| No |
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| No |
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| Yes |
| 1.) The wording in Inclusion I2 should be changed to read “including the generator terminals through the high-side of any dedicated generator step-up transformer(s) connected at a voltage of 100kV or above.” Without the use of the word “dedicated” to modify the term step-up transformer, the present wording could unintentionally ensnare distribution facilities. For example, consider a 21 MVA generator connected directly to a 12kV distribution line, with no “dedicated” generator step-up transformer. In this case, the 12kV distribution line and the upstream 138-12kV substation feeder distribution transformer might be construed to be in scope, since the substation transformer may be interpreted as being a step-up transformer (connected at 100kV or above) for the generator. This slight wording revision does not change the intent of Inclusion I2, but rather clarifies it, so as not to encompass the unintended inclusion of distribution facilities. 2.) From the BES definition and Exclusion E1 it is very clear that a 138-12kV distribution transformer serving radial load would not be considered part of the BES. However, suppose this transformer was connected to a position in a ring-bus, or a breaker-and-a-half, arrangement. Would the electrical connections between the transformer high side terminals and the two breakers in the ring-bus, or breaker-and-a-half-bus, be considered part of the BES? They would be contiguous transmission elements (bus work) operating at 138kV and supplying a radial distribution transformer. Also, tripping of this “radial” bus section would not interrupt any BES facilities, due to the station bus arrangement. As such, it would seem that this contiguous bus position supplying the radial system would not impact any BES facilities and as such should be excluded from the BES. However, take the same 138-12kV transformer but this time connected in a typical line-bus arrangement. The transformer by definition is not a BES element. As was the case above, the electrical connections between the transformer and the two breakers in the line-bus would be contiguous elements operating at 138kV and supplying a radial distribution transformer. Again, by definition and Exclusion E1 this bus section (element) would not appear to be part of the BES. However, in this case tripping of the “radial” bus section would result in an interruption to the through path of the station, and could therefore interrupt the through flow on BES facilities. Based on the above examples, since the type of bus arrangement could influence whether an element is included in the BES or not, then additional language needs to be added to the definition (either as an Inclusion or Exclusion) to make this point clear. The BES definition needs to be specific enough to eliminate any confusion as to what is included, and what is not included (particularly on the subject of substation bus arrangements supplying radial systems), and thereby greatly minimize, if not eliminate, the need to request interpretations. One way to address the bus arrangement issue would be to add a qualifier to Exclusion E1 that states, “if a radial system is supplied from a position in a substation bus arrangement, then the connections from the radial system up to the interrupting device(s) in the substation bus arrangement are also excluded from the BES, providing the tripping of the interrupting device(s) does not result in an interruption to any BES facilities when the station is operating in its normal configuration.” 3.) An FAQ document should be a specifically identified goal/product of in the SAR detailed description. An FAQ document, with examples including diagrams showing various configurations and how to apply the BES definition, is needed to add clarity to BES definitions, but should not be a substitute for a BES definition which leaves little room for interpretation. |
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| Individual |

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| J. S. Stonecipher, PE |
| City of Jacksonville Beach dba/Beaches Energy Services |
| No |
| The scope should be revised to clarify that if the BES definition is changed as a result of the technical examinations being undertaken, conforming changes should be made to the Statement of Compliance Registry Criteria, including (but not necessarily limited to) Sections I and III. The scope should also be expanded to include clarification of the relationship between the BES definition and the Federal Power Act definition of the "bulk-power system". We believe that the "bulk-power system" as defined in Section 215 is equal to the Bulk Electric System as defined by NERC plus (protection and) control systems that are covered by the standards. Section 215 defines the Bulk-Power Electric System as: "(1) The term `bulk-power system' means-- (A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and (B) electric energy from generation facilities needed to maintain transmission system reliability." The key phrase is at A: "facilities and control systems". We believe the best way to move forward is: 1) to interpret "facilities" as used in Section 215 as meaning the same as "Facilities" as used in the NERC Glossary, which would mean that the BES does not include control systems; and 2) to interpret "control systems" as used in Section 215 as those protection and control systems covered by the standards (e.g., CIP, PRC). |
| Yes |
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| No |
| There was a study performed in NPCC concerning what size generator could impact UFLS program design. We believe that study fatally flawed due to flawed assumptions on island size, etc. |
| No |
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| No |
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| No |
| We strongly suggest that the SAR be revised to be more specific. As currently worded - "Determine if there is technical justification for including the equipment which 'supports' the reliable operation of the BES"- the SAR is unclear and could lead to circularity, since equipment that is added to the BES by virtue of "supporting" the BES is likely itself "supported" by other equipment, which would then also have to be added to the BES, and so on ad infinitum. "Supported" is also a very ambiguous word, with many gradations from the significant to the insignificant, e.g., does a residential rooftop photovoltaic system "support" BES system frequency? The SDT should therefore set out the types of equipment that it will be examining, e.g. blackstart units. The SAR item should be revised to read: "Determine if there is technical justification for including blackstart units." If the SDT's intent is on protection and control systems, then, we believe that protection and control should not be defined in the BES definition effort, but rather in the PRC and CIP standards. |
| No |
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| No |
| There is a question as to what type of switch acts as the boundary between BES and non-BES. The NERC Glossary defines Facility as: "A set of electrical equipment that operates as a single Bulk Electric System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" "Operates" is the key word when considering the boundary between Facilities and non-Facilities, and therefore between BES and non-BES. We operate at switches, so, a Facility is essentially defined as the BES equipment between switches. What type of switch is the key question. If only automatic fault interrupting devices (i.e., breakers and circuit switchers) act as that boundary, it would exclude manual and motor operated disconnect switches as able to act as that boundary. The problem with using only automatic fault interrupting devices is that many radial equipment would then not be automatically excluded. For instance, consider a ring bus where a step-down transformer to distribution is connected to one of the ring-bus bus sections (i.e., between two breakers in the ring). The bus section between the two breakers is not radial and is presumably part of the BES. Usually, there is a manual disconnect switch |

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| between the bus section and the high-side of the transformer connected serially with the transformer. If that transformer high-side manual disconnect switch is not the boundary between BES and non-BES, that would make the distribution voltage breaker on the secondary side of the transformer the boundary and the entire transformer would become part of the BES. The same would be true for a radial line connected to a ring bus or breaker-and-a-half scheme; the radial line would not be automatically excluded. If it is determined that only automatic interrupting devices can act as the boundary between BES and non-BES, we would see a flood of exception requests to excempt the radial transformers and lines. All of those requests will most likely be approved because interrupting one of the paths of a ring bus or breaker-and-a-half scheme is exactly what those types of buses are designed for, and we would wind up right back to where we are now. Even if that is not the case, the industry would likely change bus designs just to be able to get the automatic radial exclusion. In other words, we'll essentially obsolete ring bus and breaker-and-a-half buses in favor of main and transfer bus schemes, which is inherently a lower reliability bus design, just to be able to get the radial exclusion. We believe that this consideration is not an efficient use of resources and should not be part of the scope; and, in fact, if the current criteria is changed, it could have an unintended consequence of reducing the reliability of the BES. |
| Yes |
| There are numerous papers and textbook discussions on the comparative reliability of different types of bus designs; e.g., ring, breaker-and-a-half, main and transfer, etc. |
| Yes |
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| No |
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| Yes |
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| No |
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| Yes |
| If our comments to question 1 are accepted and the SDT determines that the “bulk-power system” of Section 215 is equal to the Bulk Electric System as defined by the BES definition plus “control systems” as the term is used in Section 215, the SAR could include in its scope what “control systems” are included in the “bulk-power system”. |
| No |
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| Yes |
| The Statement of Compliance Registry Criteria will need to be changed if any changes are made to the BES definition, and entity registration will need to change in accordance with any changes made to the Statement of Compliance Registry Criteria. |
| Note also that I am against looking at the 100 kV bright line at all. Unfortunately, the Florida 2008 event was caused by a 138 kV event. |
| Individual |
| Thad Ness |
| American Electric Power |
| No |
| Please see response to Q3, where we respond to the SDT’s proposal to bring “contiguous BES” into scope. |

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| Yes |
| For non-generation reactive resources, a reactive limit should be identified as part of I5. |
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| No |
| It is unclear what the SDT is attemping to achieve by bringing “contiguous BES” into scope. |
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| No |
| The word “supports” is extremely vague. The SDT has worked to draft a clear definition of the BES, and vague language only deters this effort. No vague or “fuzzy” language of any kind should be used as part of the BES definition. |
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| Yes |
| There needs to be some clarification regarding the default status of an asset, as well as the order and priority of the inclusion and exclusion classifications within the definition. First, prior to any evaluation by virtue of the definition, is an asset by default excluded from the BES, or rather, it is included? In addition, once the definition is used to evaluate an asset which has both inclusion attributes and exclusion attributes, which of the two classifications has greater weight? For example, if an asset is first included by the BES definition inclusion criteria can it then be excluded by BES definition exclusion criteria? Or instead, if an asset is first excluded by BES definition exclusion criteria can it then be included by the BES definition inclusion criteria? AEP’s recommendation is that an asset, by default, not be considered part of the BES. Next, the asset would be evaluated by the inclusion criteria as specified within the definition. Next, any asset explicitly included by the inclusion criteria is then evaluated using the exclusion criteria. Once the entity has made their determination based on the definition, exception requests could then be made to include or exclude assets as appropriate. We believe our interpretation is what is implied by the draft definition, however, this needs to be explicitly communicated within the definition itself. The SDT should consider clarifying the effective date for an asset whose status is changed after the initial implementation plan for the revised definition has concluded. If an asset is initially excluded and the conditions surrounding the exclusion change such that the exclusion no longer applies, is the asset required to abide by all BES standards immediately upon inclusion or is the asset permitted a grace period in which to come into compliance? Consider for example, a site comprised of two units, each connected at 138 kV and with a nameplate rating of 17 MVA, which would not be included in the BES as they would fail to meet the requirements of I2. If a third unit, operating at 138 KV with a nameplate rating of 50 MVA is constructed at the site, all three units would then be included under I2. Would all three units then be required to be fully compliant |

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| immediately upon commercial availability of the third unit? Similar scenarios alse also possible for exclusions E1, E2, E3 and E4. |
| No |
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| Yes |
| AEP believes there could be business impacts as a result of the potential impacts to FAC-001, specifically R1. Meeting the requirements specified in FAC-001 is dependent on the BES definition and its application. |
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| Individual |
| Rich Salgo |
| NV Energy |
| Yes |
| To the extent that changes are made to the BES definition, there could be corresponding changes necessitated in the RoP Technical Principles in order to ensure a comprehensive product. I support this portion of the scope only if changes to the BES Definition necessitate adjustment of the Technical Principles. Otherwise, this portion of the scope should be eliminated. |
| Yes |
| The existing thresholds adopted in the BES Definition from Phase 1 were not vetted technically, and they therefore warrant examination in phase 2. |
| No |
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| No |
| I do not feel that there is anything to be gained by this pursuit. If a particular element is not captured in the definition or the exception process, then it stands to reason that there is no reliability rationale for its inclusion. Inclusion of such an element purely to satisfy a continuity principle contradicts the rigor of the definition and exception process. Bear in mind that NERC Standard Requirements cover facilities outside of the defined BES, thereby covering any discontinuities in the BES itself. Therefore, the BES need not encompass each and every element that has a reliability function. |
| No |
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| No |
| In the statement above from the proposed SAR, an irreconcilable situation is being suggested: including IN the BES equipment that “supports” the BES. The body of NERC Standards should be the vehicle for determining supporting equipment and systems that must be operated in accordance with defined requirements. Perhaps this item in the SAR should be re-stated to pursue the identification of “associated equipment” as used in the NERC Glossary definition of “Transmission”. |
| No |
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| No |
| The filed BES Definition specifically and purposefully dropped the reference to automatic interrupting devices. The same legal obstacles that prevented such an inclusion in Phase 1 of the BES definition continue to be present. Under the federal regulations, the scope of the Bulk Power (Electric) System excludes radial facilities without any further qualification of having automatic fault interruption devices present. From a reliability perspective, however, the PRC Standards can continue to be the instrument to prevent any gaps in reliability through their applicability clauses and the language of the requirements themselves. |
| No |
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| No |
| This portion of the scope is unnecessary. The NERC Standards are, and can continue to be, drafted in a manner that continues to impose requirements on the applicable Cranking Paths absent their |

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| explicit inclusion in the BES. |
| No |
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| No |
| With the established Exception Process and carve-out in the Definition for Radial and Local Network facilities, the voltage threshold becomes far less important, and the SDT will encounter extreme political pressure to uphold the 100kV threshold. While we may indeed disagree with 100kV as a threshold in any BES discussion, it does serve to at least put a perimeter around the ballpark for those elements that should at least be considered for inclusion. |
| No |
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| No |
| We believe that holding the bright line at zero power flow out of the candidate local network is most appropriate. For those instances where an anomaly or other unusual circumstance results in outward power flow from the subject network, then the Exception Process is the most effective means to have the exclusion considered. |
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| No |
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| No |
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| No |
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| |
| Individual |
| Erik Kysar |
| Brown & Kysar |
| No |
| We are concerned that the SAR is broadly written so that “any and all aspects of the Phase 1 definition are open to discussion and possible revision.” We are concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at definition that [ORGANIZATION] believes will be workable and strongly supports. [ORGANIZATION] therefore believes Phase II should be focused on the specific questions set forth in the SAR and the SAR should be revised so that it focuses on those specific issues. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the SDT and “a consensus of stakeholders.” As long as “consensus” is understood to be unanimous or near-unanimous support for addressing the new issue, [ORGANIZATION] is comfortable with supporting the SAR as written. To the extent “consensus” is interpreted to mean something less than near-unanimous support, [ORGANIZATION] opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide “greater clarity,” we support the SDT’s efforts to better define the obligations with respect to each of these issues. First, we support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In [ORGANIZATION]’s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC |

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| itself states, the SCRC is intended only to identify “candidates for registration.” SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term “non-retail generation.” The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. Many commenters during Phase I identified this term as one that should be clarified. The SDT responded “Non-retail generation is a widely used and understood term and is not defined here.” We are encouraged that the proposed SAR would revisit this question. The number of comments related to this item makes it is clear the term is not widely understood, and we wish to ensure the regulated community, the REs, NERC, and FERC all use the same definition. We also suggest that the definition should reside either in the BES definition document or separately in the NERC Glossary. For similar reasons, we support an effort to further clarify the reference to “dispersed power resources” in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a “collector system” and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. This is of particular concern in a number of states that have adopted policies favoring construction of small, dispersed, distribution-level renewable generation. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. As noted in our answer to Question 9, however, we believe demarcation should be considered a part of the Phase II technical analysis rather than as just clarification. |
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| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by including only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also |

note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that the interconnection factilities connecting BES generators to the bulk transmission system must also be classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, the result would be that large segments of the nation’s distribution systems are classified as BES. This would squarely violate the FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It is also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate

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| only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. Finally, we suggest that, rather than considering whether the BES should be contiguous or non-contiguous, the SDT should focus on developing principles for use in the Exceptions/ Inclusions process that would define whether an Element is “necessary for” the operations of the BES. Where the principles would provide for non-contiguous BES Elements, such non-contiguous Elements should be included in the BES only through the Inclusion process. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| We note that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which ‘supports’ the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, we oppose including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power,” 16 U.S.C. § 824o(a)(1), but the question contemplates inclusion of distribution facilities in the BES. If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is one of whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. We are nonetheless concerned that the question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. Further, the requirement to have automatic fault-interrupting devices (“AFID”) at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. Please consider a loop-fed, TO-owned bulk transmission line that is tapped with a DP-owned radial line that would be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100 kV. Normally, looped lines use distance (impedance) as a form of protection. Two or more zones are used. The first generally has no intentional delay and is set to slightly under-reach the remote end bus. The second is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 |

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| required an AFID at the tap point, and a DP wishes to avoid having its tap line classified as BES, it would be required to install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP's plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section setting depends on the next, the process will probably continue until the next DP announces its AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP's fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since '09) uses the uppercase NERC defined term Protection System, which excludes fuses. We don't see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP's level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID-protected radial line and the hard-tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. While there may be exceptions to what is stated above, if a RE can show the radial line or Local Network does impact the BES, they can seek an Inclusion of the relevant radial or LN. |
| No |
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| Yes |
| We, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that a threshold of at least 200 kV, rather than 100 kV, should be used, at least for WECC. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities,we believe there is no technical justification for including facilities operating at 100-kV in the BES. We therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. We note, further, that differences between the Eastern Interconnection and the Western Interconnection may well justify a different threshold for the two interconnections. There are several differences between the two interconnections that may justify different treatment. For example, the Western transmission system generally links isolated generators with load centers that are located far from the generator using long transmission lines, while generation and load in the Eastern system are usually much closer geographically and the system is therefore much more networked. In addition, the Western system is generally stability-limited, while the Eastern system is generally thermally-limited. And the Western system uses a path rating approach while the Eastern system uses a flow-based approach. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior |

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| to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100-kV or 200-kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend its work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200 kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230 kV, 345 kV, and 500 kV as typical bulk transmission voltages. Facilities operating below 230 kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200 kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100 kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230 kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100 kV and 200 kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200 kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200 kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200 kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200 kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200 kV is significantly below that of the 200-300 kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates that most transmission elements in the Western Interconnection operate at voltages above 200 kV, while lines operating in the range of 100-200 kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100-kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200-kV threshold with an inclusion mechanism to identify the minority of 115-kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| We are concerned that the Local Network exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." We believe that, as long as the power flow is generally into the LN and the LN is not |

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| operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in inconsequential amounts or only during unusual contingencies. We support technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. While we support technical analysis of this issue, we are concerned that the reference to “certain conditions” suggests that the technical analysis will not focus on LNs operating as intended, but will delve into contingencies, even contingencies that are extremely remote. We urge the SDT to analyze this question for LNs operated as intended under normal conditions. If, in unusual circumstances, flows might emanate from an LN that do not emanate under normal circumstances, the relevant RE, TOp, or RC can use the Inclusion process to seek inclusion of that LN in the BES if it can demonstate the LN has a substantial impact on operation of the bulk transmission system under reasonably foreseeable contingencies. |
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| Yes |
| As noted in our response to Question 1, we agree that Phase II should address the question of defining the points of demarcation between the BES and non-BES Elements. This is a critical question for clearly defining the compliance obligations of Registered Entities. We believe that demarcation is a technical question, and therefore believe Phase II should approach demarcation as a technical question rather than as merely a clarification. If the SDT puts together a technical record supporting its approach to demarcation, we believe the resulting standard will be more likely to survive regulatory review. We again note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. We also believe that additional work is necessary to define the relationship between the Exclusions and Inclusions. Some of the Inclusions and Exclusions as currently provide language that explains how they operate if an Element falls into both an Exclusion and Inclusion. For example, Inclusion I1 specifies that certain transformers must be included in the BES “unless excluded under Exclusion E1 or E3.” This makes clear that transformers operating within a radial or Local Network subject to exclusion are not part of the BES even if they otherwise would be included as a result of Inclusion I1. We are concerned, however, that there is no clear general rule on how to classify an element that meets both an Inclusion and an Exclusion. For example, a capacitor located on radial line, and therefore excluded by operation of Exclusion E1 might nonetheless meet the requirements for inclusion under Inclusion I5. A method for resolving this conflict should be spelled out in the definition so that future disputes about conflicting Inclusions and Exclusions can be avoided. As a starting point, we suggest that the phrase at the end of Inclusion I1 (“unless excluded under Exclusion E1 or E3”) be added to Inclusions I4 and I5, so that all non-generation equipment that is located on a radial or in a LN is excluded consistent with the intent of Exclusions E1 and E3. Similarly, the phrase “unless excluded under Exclusion E2” should be added at the end of Inclusion I2 so that definition makes clear that customer-owned, behind-the-meter generation is always excluded under Exclusion E2. While the relationship between the Inclusions and Exclusions might reasonably be viewed as just a clarification of the current definition, we note it in this question because we believe additional technical analysis may be needed to resolve potnential conflicts between Inclusions and Exclusions, at least in some circumstances. In addition, advocate that the SDT prepare flow-through diagrams that graphically represent how particular Elements will be handled under the BES Definition, both as a matter of guidance to regulated entities and as a means of identifying potential conflicts between Inclusions and Exclusions that should be addressed by the SDT. |
| Yes |
| As reflected in our response to Question 1,we are concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. If there is near-unanimous agreement that these clarifications should be addressed in |

Phase II, we recommend the following clarifications: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100 kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100 kV or above, which is why the definition uses the word “and” (“the primary and secondary terminals”). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100 kV are not part of the BES. Transformers with no secondary terminals operating at or above 100 kV are also excluded from the BES.” This language will help ensure that there is no controversy over whether the SDT’s use of the word “and” in the phrase “the primary and at least one secondary terminals” was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100 kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100 kV or above.” As noted in our answer to Question 9, we also believe that language should be added to Inclusion 2 making clear how an Element will be handled if it falls both within this Inclusion and within the Exclusions. The same is true of the other Inclusions that lack such language. 3) With respect to Inclusion I4, which addresses dispersed power producing resources, which suggested adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While [ORGANIZATION] strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather han a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 5) With respect to Exclusion 2, which addresses generation owned by a retail customer, we are concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 6) With respect to the Local Network (“LN”) exclusion, Exclusion E3, we believe further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100 kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from

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| this phrase. This is so because LNs are not used for transmission and the use of the term "transmission Elements" is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term "transmission Elements" is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. We also believe that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: "The LN does not transfer energy originating outside the LN for delivery through the LN." We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: "The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN." We believe the italicized language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, we believe that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
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| Individual |
| Keira Kazmerski |
| Xcel Energy |
| Yes |
| Xcel Energy is particularly interested in clarifying Inclusion I4. |
| Yes |
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| No |
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| Yes |
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| No |
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| No |
| Xcel Energy is concerned that the term " …equipment that supports…" might be overly broad and include equipment that is not considered BES into the fold. |

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| Yes |
| Phase 1 included reactive resources but did not define an MVA or MVAr size limitation. Xcel Energy believes Phase 2 should refine Inclusion I5 to include a size limitation analogous to I2 and I4 for generators. |
| No |
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| Group |
| MRO NSRF |
| Will Smith |
| No |
| The SAR should include review of I4 to more precisely define which portions of a dispersed power resource are included within the BES to avoid inclusion of multiple items that are not significant to the reliability of the system. The SDT has identified several issues that are included in the scope of Phase 2 of the project that are associated with the technical aspects of the definition and require technical justification to drive a revision to the definition. Compelling technical justification is an essential component in moving any revision forward that addresses the technical nature of the BES definition. The SDT is seeking to identify existing technical justifications (i.e., completed studies, technical papers, etc.)and requests your assistance to properly identify resources available to the SDT which will facilitate the SDT's work in prioritizing its efforts. Note: The SDT does not intend to respond to all responses associated with an entity's knowledge of existing technical justification (i.e. analysis methodologies, completed studies, technical papers, etc.). The SDT is collecting potential resources that could assist in the development of compelling technical justification. Please clarify the intent of I4. |
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| Yes |
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| No |
| The revised bulk electric system definition provides a bright line criterion for what is included in the bulk electric system and including "support" equipment detracts from the objectives of establishing this "bright line." |

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| No |
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| The E1 and E3 exclusions as written provide adequate definition and incorporation of automatic interrupting devices does not improve the exclusion criterion. |
| No |
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| No |
| Including cranking paths could add system elements not otherwise included in the base definition or other inclusions and could add unnecessary complication to the definition. |
| No |
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| Yes |
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| No |
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| Yes |
| The criterion should reflect the normal operation of the local network and not require the network to be included in the BES because of infrequent, abnormal situations. |
| No |
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| No |
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| Yes |
| : A statement should be added to indicate that an element that does not meet the base BES definition or any of the inclusion criteria is not a part of the BES. This is suggested to avoid an interpretation that elements that are not exluded by any of the exclusion criteria are by definition included. Please ensure that one methodology is stated in figuring out what is part of the BES. An entity needs to start with the root BES definition then review the Inclusions and Exceptions. Not the other way around which may have a different outcome. |
| No |
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| No |
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| Individual |
| Steve Alexanderson |
| Central Lincoln |
| No |
| Central Lincoln is concerned that the SAR is broadly written so that “any and all aspects of the Phase 1 definition are open to discussion and possible revision.” Central Lincoln is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. Central Lincoln believes Phase II should be focused on the specific questions set forth in the SAR and the SAR should be revised so that it focuses on those specific issues. Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. As long as “consensus” is understood to be unanimous or near-unanimous support for addressing the new issue, Central Lincoln is comfortable with supporting the SAR as written. To the extent “consensus” is interpreted to mean something less than near-unanimous support, Central Lincoln opposes this provision of the SAR. We support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In Central Lincoln’s view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify “candidates for |

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| registration." SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term "non-retail generation." The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. Many commenters during Phase I identified this term as one that should be clarified. The SDT responded "Non-retail generation is a widely used and understood term and is not defined here." We are encouraged that the proposed SAR would revisit this question. The number of comments related to this item makes it is clear the term is not widely understood, and we wish to ensure the regulated community, the REs, NERC, and FERC all use the same definition. We also suggest that the definition should reside either in the BES definition document or separately in the NERC Glossary. We support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. FPA Section 215 defines "bulk-power system" to mean "facilities and control systems necessary for operating an interconnected electric energy transmission network" and, specifically with respect to generation facilities, includes only those generators "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are "necessary" for reliable operation of the bulk transmission system. |
| Yes |
| Snohomish County PUD produced a document entitled "White Paper: A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System" (April 2011). We understand Snohomish has attached that document to its comments on the Phase II SAR. |
| No |
| The SDT should be focusing on whether the specific "facilities and control systems" at issue are "necessary for" operating the bulk interconnected transmission network and whether energy from generation facilities is "needed to maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). The SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. There is no basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. A contiguous BES definition, will inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operations of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. We suggest that, rather than considering whether the BES should be contiguous or non-contiguous, the SDT should focus on developing principles for use in the Exceptions processes that would define whether an Element is "necessary for" the operations of the BES. Where the principles would provide for non-contiguous BES Elements, such non-contiguous Elements should be included in the BES only through the Inclusion process. |
| Yes |
| See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group |

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| for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| Central Lincoln notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which ‘supports’ the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, Central Lincoln opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power,”. The relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. |
| No |
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| No |
| We understood this subject was discussed during Phase I, and see no reason to reopen it. Further, the requirement to have automatic fault-interrupting devices (“AFID”) at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. Please see our discussion below. |
| Yes |
| Our technical justification is provided here. Please consider a loop-fed, TO-owned bulk transmission line that is tapped with a DP-owned radial line that would be excluded per E1 as it is presently written. The radial line terminates at one or more substations that step the voltage down to below 100 kV. Normally, looped lines use distance (impedance) as a form of protection. Two or more zones are used. The first generally has no intentional delay and is set to slightly under-reach the remote end bus. The second is set to overreach the remote end, and is delayed to allow the Zone 1 element of the next section to operate first. A relatively short tap line somewhere in the middle is likely to be fully covered by Zone 1. If the tap line is long, or located near one of the ends of the line section, one or both of the relays will likely see some faults on the tap line as being in Zone 2. Either way, the clearing time is fixed. The transformer at the end of the tap line presents an impedance the distance elements will not see past, so faults on the low voltage side will not cause the distance protection to operate. All works well, since the line section and the tap line are fully covered for faults. If E1 required an AFID at the tap point, and a DP wishes to avoid having its tap line classified as BES, it would be required to install an AFID at the tap point. The AFID itself will be BES, but fortunately there is an AFID available that is not subject to the PRC standards: a fuse. A fuse will not clear with a definite time like the distance relay, but has an inverse time/current characteristic. If no changes are made to the settings, the relays will continue to clear most faults faster than the fuses with the same result as the un-fused hard tap. After learning of the DP’s plan, the TO protection engineers might review their settings. Modern microprocessor based relays can combine the distance elements with inverse time overcurrent curves logically so the line end relays can coordinate with the newly added fuse. The protection engineer would then look at the next adjacent line section, then the next one, and so on. Since each line section setting depends on the next, the process will probably continue until the next DP announces its AFID plan and the protection engineers will begin again. Under the NERC standards, though, the TO is not required to coordinate with a DP’s fuse. PRC-001-1 only requires TOs and GOs to coordinate amongst themselves, and PRC-001-2 (stalled since ’09) uses the uppercase NERC defined term Protection System, which excludes fuses. We don’t see TOs rushing to re-coordinate their entire systems in order to coordinate with all the newly added fuses. So the fuse installation is unlikely to isolate faults on the tap line while keeping the looped line section in service. The fuse addition has only decreased the DP’s level of service by introducing an added failure point. This reduction can be mitigated by using a higher current fuse than needed, making the minor difference between the AFID-protected radial line and the hard-tapped version that much less. The best design for a radial connection would be to install three breakers looking in all directions, so that the looped line is re-sectioned. This would allow faults on the radial line to be isolated without affecting the loop flow, and allow the radial line to remain energized for faults on either one of the |

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| two adjacent loop line sections. The TOs, however, have approved the more economical hard tap design. We believe that if the presence of the hard tapped radial line were likely to cause instability, or cascading outages, or negatively impact the BES in any way, they would have never been allowed in the first place. In conclusion: The presence of an AFID at the tap point is unlikely to provide any benefit to the BES, and the lack of one unlikely to negatively impact the BES. Our argument can be easily be extended to E3 Local Networks that originate from tapped BES lines. While there may be exceptions to what is stated above, if a RE can show the radial line or Local Network does impact the BES, they can seek an Inclusion of the relevant radial or LN. |
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| No |
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| Yes |
| Central Lincoln, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that a threshold of at least 200 kV, rather than 100 kV, should be used, at least for WECC. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities, Central Lincoln believes there is no technical justification for including facilities operating at 100-kV in the BES. Central Lincoln therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. We note, further, that differences between the Eastern Interconnection and the Western Interconnection may well justify a different threshold for the two interconnections. There are several differences between the two interconnections that may justify different treatment. For example, the Western transmission system generally links isolated generators with load centers that are located far from the generator using long transmission lines, while generation and load in the Eastern system are usually much closer geographically and the system is therefore much more networked. In addition, the Western system is generally stability-limited, while the Eastern system is generally thermally-limited. And the Western system uses a path rating approach while the Eastern system uses a flow-based approach. |
| Yes |
| See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. |
| Central Lincoln does not support the inclusion of contiguencies in the bright line definition. Contiguencies might be considered for the exception process, but the bright line criteria should remain a simple inspection process not requiring a detailed study. We do support allowing a technically justified threshold outflow during normal system conditions, since the zero outflow may improperly include local networks in the BES that are not necessary for reliable operation. |
| No |
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| Yes |
| As noted in our response to Question 1, we agree that Phase II should address the question of defining the points of demarcation between the BES and non-BES Elements. This is a critical question for clearly defining the compliance obligations of Registered Entities. We believe that demarcation is a technical question, and therefore believe Phase II should approach demarcation as a technical question rather than as merely a clarification. If the SDT puts together a technical record supporting its approach to demarcation, we believe the resulting standard will be more likely to survive regulatory review. We also believe that additional work is necessary to define the relationship between the Exclusions and Inclusions. Some of the Inclusions and Exclusions as currently written provide language that explains how they operate if an Element falls into both an Exclusion and Inclusion. For example, Inclusion I1 specifies that certain transformers must be included in the BES "unless excluded under Exclusion E1 or E3." This makes clear that transformers operating within a radial or Local Network subject to exclusion under Exclusions E1 or E3 are not part of the BES even if they otherwise would be included as a result of Inclusion I1. We are concerned, however, that there is |

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| no clear general rule on how to classify an element that meets both an Inclusion and an Exclusion. For example, a capacitor located on radial line, and therefore excluded by operation of Exclusion E1 might nonetheless meet the requirements for inclusion under Inclusion I5. A method for resolving this conflict should be spelled out in the definition so that future disputes about conflicting Inclusions and Exclusions can be avoided. As a starting point, we suggest that the phrase at the end of Inclusion I1 (“unless excluded under Exclusion E1 or E3”) be added to Inclusions I4 and I5, so that all non-generation equipment that is located on a radial or in a LN is excluded consistent with the intent of Exclusions E1 and E3. Similarly, the phrase “unless excluded under Exclusion E2” should be added at the end of Inclusion I2 so that definition makes clear that customer-owned, behind-the-meter generation is always excluded under Exclusion E2. While the relationship between the Inclusions and Exclusions might reasonably be viewed as just a clarification of the current definition, we note it here because we believe additional technical analysis may be needed to resolve potential conflicts between Inclusions and Exclusions, at least in some circumstances. In addition, we advocate that the SDT prepare flow-through diagrams that graphically represent how particular Elements will be handled under the BES Definition, both as a matter of guidance to regulated entities and as a means of identifying potential conflicts between Inclusions and Exclusions that should be addressed by the SDT. |
| Yes |
| As reflected in our response to Question 1, Central Lincoln is concerned that the broad language of the Phase II SAR creates the danger of “mission creep” that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. If there is near-unanimous agreement that these clarifications should be addressed in Phase II, we recommend the following clarifications: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES “if the primary terminal and at least one secondary terminal” are operated at 100 kV or higher. We believe the SDT’s intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: “Transformers with primary terminals that operate at or below 100 kV are not part of the BES. Transformers with no secondary terminals operating at or above 100 kV are also excluded from the BES.” 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing “. . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above” so that the Inclusion covers transformers with terminals “connected at a voltage of 100 kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100 kV or above” 3) With respect to Inclusion I4, we suggest adding at the end of the Inclusion the phrase “. . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2.” 4) With respect to Exclusion E1, which covers Radials, we believe two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While Central Lincoln strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: "Normally-open switching devices between radial elements does not affect this exclusion." The plural form of "devices" ensures that the presence of more than one normally open device does not result in improper classification. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. |
| Yes |
| Please see answer to Q7. |
| No |
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| PacifiCorp |
| Sandra Shaffer |
| No |
| Since many of the existing and proposed requirements are based on arbitrary numbers (i.e., technical justifications do not exist for the 100 kV, 20 MVA, or 75 MVA thresholds), PacifiCorp does not agree with this scope to determine where there are “compelling” technical justifications for the revisions to the definition of BES developed in Phase 1 of this project. A “compelling technical justification” means convincing or absolutely no room for error. PacifiCorp does not believe anyone can develop a “compelling” justification for the new definition of BES. PacifiCorp recommends the term “compelling technical justification” be changed to “reasonable technical justification.” Reasonable technical justification means governed by or being in accordance with reason or sound thinking. As a general comment, the SDT should consider each potential BES element from two perspectives: 1) what would happen to the reliability of the interconnected system if the element under consideration was removed, either suddenly or gradually, from the interconnected system; and 2) what would happen to the reliability of the interconnected system if the element was not available to respond upon the loss of critical BES elements (N-1, N-2 type scenarios) from the interconnected system. |
| Yes |
| Because the BES definition is tied to a voltage level, additional clarification needs to be provided which will allow an entity to determine the appropriateness of including or excluding an element or elements from the BES. Reactive devices used to support local network load should not be included as BES elements (see Exclusion 4). |
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| Yes |
| The SDT should examine this, but PacifiCorp does not support the assumption that there is a reliability benefit of a contiguous BES at lower (<200 – 300 KV) voltages associated with cranking paths, particularly where more than one cranking path may exist. Additionally, if the reliability benefit of a contiguous BES is assumed, generation limits associated with the BES (75 MVA) will inadvertently include transmission which should not be in the BES. |
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| No |
| Supporting equipment should not be included in the BES definition. UFLS and UVLS relays are examples of equipment that support the reliable operation of the BES, but are not currently part of the BES. It is not critical if the relays fail, yet it is important to have enough relays within the system to respond to a frequency or voltage deviation on the interconnected system. Now the SDT is proposing to include distribution substations and relays as part of the BES. This approach is problematic because distribution voltages are currently not in the BES – and they ought not to be. Instead, the SDT should look at these elements from the two perspectives described above in our response to Question 1. |
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| Yes |
| The SDT should at least pursue a technical justification to determine if these devices should or should not be present at BES connection points. It makes sense to not require an interrupting device on a radial system (E1), but it does make sense to require interrupting devices at all local network connection points to the BES (E3). |
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| Yes |
| The SDT should at least determine whether cranking paths should or should not be included in the BES definition (See response to #3). However, blackstart resources have already been addressed and further evaluation is not required. |
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| Yes |
| The selection of 100kV as the bright-line voltage level was arbitrary, and merits further examination. Some 100 kV elements certainly should be considered part of the BES as long as there exist clear and consistent guidelines for how to classify such assets. However, lowering the voltage level from 200 kV |

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| to 100 kV resulted in the inclusion of elements used to support distribution, and was therefore overinclusive in some cases. We believe any bright-line test needs to maintain some flexibility. For example, the proposed rules allow for the inclusion of elements with a voltage below the bright-line limits if they are important to the reliability of the interconnected system. |
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| Yes |
| A local network will often have inadvertent power flow out of it, just due to the physics of electricity. The maximum allowable amount should be a percentage or range of percentages being added to the interconnected system. |
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| Yes |
| The SDT should pursue, with NERC's blessing, the ability to differentiate requirements for different levels of generation. For instance large generators may require a contiguous BES whereas smaller generators may not require a contiguous BES. The appropriate generator levels should be established by the SDT along with any necessary exclusions. |
| No |
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| No |
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| Yes |
| Many reliability standards associated with the BES will need to be modified to conform to the new definitions. |
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| Individual |
| Martyn Turner |
| LCRA Transmission Services Corporation |
| Yes |
| In general, LCRA TSC supports the effort to technically justify thresholds for transmision elements presently included in the BES defintion; Regarding the exlcuisons, LCRA TSC suggests adding a scope to "Determine if there is a technical justification to support the 300 kV limitation for Local Network elements." |
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| Group |
| Western Electricity Coordinating Council |
| Steve Rueckert |
| No |
| WECC staff believes that several of the thresholds included in the Phase 2 SAR will be difficult to technically justify so WECC staff recommends retention of the current established thresholds. If a technical justification for a different threshold exists, then WECC staff may support the change. WECC staff has some language changes/additions to the SAR. See recommendations in responses to questions 10 and 13. |
| No |
| WECC staff believes the SDT should pursue the development of thresholds for the Reactive Power Resources. The existing FERC-approved and the proposed Phase 1 BES definitions do not have any thresholds for Reactive Power Resources. For the Real Power Resources, WECC staff recommends retention of the existing thresholds. If a different threshold is proposed for the Real Power Resources, then the SDT should pursue technical justification for the new threshold. WECC staff believes that in E1, the SDT may have inadvertently excluded individual generators on radial systems rated between 20 MVA and 75 MVA that were intended to be included in I2. The reason WECC staff believes the exclusion of these generators was inadvertent, is that virtually all individual generators between 20 MVA and 75 MVA are on radial systems. Thus, the exclusion of these generators in E1 defeats the purpose of the inclusion in I2. |
| No |
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| Yes |
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| No |
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| No |
| The existing FERC-approved and the proposed Phase 1 BES definitions do not include equipment that “supports” the reliable operation of the BES. These are included by the specific NERC Standards and should remain in the standards instead of including them in the BES definition. |
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| Yes |

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| No |
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| No |
| WECC staff believes the Blackstart Resources and cranking paths must be included in the BES definition but do not need technical justification to be included. Blackstart Resources, regardless of size, and Cranking Paths must be retained as part of the BES definition because they are critical to system restoration after a disturbance. They are necessary for the reliable operation of the BES after a disturbance. |
| No |
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| No |
| The existing FERC-approved and the proposed Phase 1 BES definition both have the 100-kV bright line so it is unnecessary to develop a technical justification for the 100-kV bright line. WECC staff recommends retention of the 100-kV bright line. If the SDT proposes a new bright line-level, then the SDT should pursue technical justification for the new bright-line level. |
| No |
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| No |
| WECC staff supports retention of the current local network definition included in the Phase 1 BES definition, which requires that no power can flow out of the local network. This would not preclude local networks that have small amounts of power flowing out of the network or power flowing out of the network in limited instances from being excluded through the exceptions process. |
| No |
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| No |
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| Yes |
| WECC staff believes that the Phase 2 SAR must include a provision for clarification on the note on Exclusion E1 regarding a normally open switch. The note “Note – A normally open switching device between radial systems, as depicted on prints or one-line diagrams for example, does not affect this exclusion.” will cause confusion due to the lack of clarity as to how the normally open switch is identified. Is the intent that the normally open switch be identified as such on the one-line diagram with a N.O. designation? WECC staff has a recommended clarification to reword the sentence to read: “Note – A normally open switching device identified on the print or one-line diagram as such (i.e., N.O. designation) does not nullify this exclusion.” |
| No |
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| No |
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| WECC staff has the following comments on the SAR: 1) WECC staff believes that the development of a clear and objective methodology and criteria for the Exceptions process is imperative. To ensure consistency between the regions, language must be added to the SAR that requires the development of clear and objective technical methods and criteria for the exception process. The current language in the scope of the SAR requires only that the SDT review the exceptions process, which potentially could result in no action. 2) WECC staff notes that the following section in the SAR was not addressed in the questions in the comment form and agrees with the SDT that additional clarification is necessary: Provide improved clarity to the following: a) The relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693 b) The use of the term “non-retail generation” c) The language for Inclusion I4 on Dispersed Power Resources d) The appropriate ‘points of demarcation’ between Transmission, Generation, and Distribution |
| Individual |
| Eric Lee Christensen |

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| Snohomish County PUD |
| No |
| SNPD is concerned that the SAR is broadly written so that "any and all aspects of the Phase 1 definition are open to discussion and possible revision." SNPD is concerned that this broad language would allow the work of the Phase I process to be revisited wholesale. The SDT, the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the Phase I process and have arrived at a definition that SNPD believes will be workable and strongly supports. SNPD therefore believes Phase II should be focused on the specific questions set forth in the SAR, and the SAR should be revised so that it focuses on the issues specifically listed. While we agree the Phase II process is necessary to conduct technical analysis on the issues the SDT has identified, Phase II should not be used to re-open the fundamental structure of the BES Definition or to unwind the consensus achieved by the SDT on the Phase I definition. That being said, we recognize that the SDT may encounter unanticipated technical issues and that it is therefore prudent to include a mechanism allowing the SDT to address such issues if there is agreement by the SDT and "a consensus of stakeholders." As long as "consensus" is understood to be unanimous or near-unanimous support for addressing the new issue, SNPD is comfortable with supporting the SAR as written. To the extent "consensus" is interpreted to mean something less than near-unanimous support, SNPD opposes this provision of the SAR. We set forth our views on each of the specific technical questions posited in the SAR in our response to the appropriate questions below. With respect to the four issues for which the SAR proposed to provide "greater clarity," we support the SDT's efforts to better define the obligations with respect to each of these issues. First, we support the SAR's intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria ("SCRC"). In SNPD's view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify "candidates for registration." SCRC at p.3, § 1 (emph. added). On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Similarly, we support clarification of the term "non-retail generation." The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. Many commenters during Phase I identified this term as one that should be clarified. We are encouraged that the proposed SAR would revisit this question. The number of comments related to this item makes it clear the term is not widely understood, and we wish to ensure the regulated community, the REs, NERC, and FERC all use the same definition. For similar reasons, we support an effort to further clarify the reference to "dispersed power resources" in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a "collector system" and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, it is very unlikely that more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase II. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion 4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. As noted in our answer to Question 9, however, we |

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| believe demarcation should be considered a part of the Phase II technical analysis rather than as just clarification. |
| Yes |
| We agree that the SDT should pursue a technical justification for Real and Reactive Power Resource thresholds because there is no apparent technical justification for the thresholds in the BES definition, as currently proposed. The definition that resulted from the Phase I Standards Development Process contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100 kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 75-MW generator located at or near a constrained transmission path may play some role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 75-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from ordinary variations in demand within the distribution system. |
| Yes |
| In April 2011, SNPD released a “White Paper: A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System,” which discusses at some length a methodology for distinguishing BES from non-BES Elements based on their performance in the electric system. We have inserted the text of the White Paper below and will provide a copy to the chairman of the SDT. White Paper A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System April 2011 This White Paper proposes a transmission planning (“TPL”) “performance-based” process to determine the local distribution facilities the North American Electric Reliability Corporation (“NERC”) must exclude from the Bulk Electric System (“BES”) pursuant to Section 215(a)(1) of the Federal Power Act (“FPA”). This process would apply to those local distribution facilities that are not automatically excluded under a bright-line BES definition. Consistent with Federal Energy Regulatory Commission (“FERC”) Order Nos. 743 and 743-A, a performance-based exemption process would be objective, consistent, and transparent, and would adequately differentiate between local distribution and transmission, i.e., BES, facilities. I. What Is Reliability? FPA Section 215 authorizes NERC to promulgate “reliability standards,” subject to FERC approval. Section 215 defines “reliability standard” to mean a properly-approved requirement “to provide for the reliable operation of the bulk-power system.” The statute, in turn, defines “reliable operation” to mean “operating the elements of the bulk-power system within equipment and electric system thermal, voltage, and stability limits so that instability, uncontrolled separation, or cascading failures of such system will not occur as a result of sudden disturbances, including . . . unanticipated failure of system elements.” II. What Is “Customer Service” or “Level of Service” (“LOS”)? Local customer service or LOS relates to service failures on local utility systems that are wholly internalized rather than spilling onto the interconnected regional grid. These types of service failures relate to local |

customer service and LOS standards. The customers of those utilities will bear the full cost of complying with internal LOS standards and will obtain the full benefit of compliance to the extent that service levels on those systems improve. Accordingly, state public utility commissions (for regulated utilities) and independent boards (for non-regulated utilities) can fully and accurately weigh whether the benefits of compliance with such standards are justified by the costs they will pay. Intervention by NERC and a Regional Entity is not needed because a utility's actions related to level of service on its own system will neither unduly burden the customers of other systems, threaten the reliable delivery of power to those customers, nor create incidental benefits to those remote customers. In the absence of the need to protect customers of systems remote from the consequences of decisions made by an individual utility, there is no warrant for NERC or a Regional Entity to interfere with a utility's internal decision-making about the appropriate LOS to its own customers, and the costs that will be borne by those customers to achieve any particular level of service. In fact, in the "Savings Provisions" of Section 215, Congress specifically included language prohibiting NERC and Regional Entities from enforcing "compliance with standards for adequacy" of electric service. By law, these remain the exclusive province of local decision-makers. III. The Need for a Material Impact Test In Order No. 743-A, FERC clarified that a material impact test is appropriate in the reliability context if the test can be shown to identify facilities needed for reliable operation. The following example of an outage demonstrates the need for an impact test to distinguish between LOS and Reliability, i.e., local distribution facilities and BES facilities. A. Pre-Event Facts Local Utility Administration ("LUA") owns a 115 kV system that moves power from two points of delivery ("POD") and serves 1000 MW of load. A DC battery rack had an unexpected failure a few days after it was routinely inspected and LUA has not implemented Supervisory Control and Data Acquisition ("SCADA") so the DC battery voltage is not continuously monitored. The LUA system interconnects with BES Company's system which consists of 230 kV and 500 kV lines. B. Event Facts A fault occurs and the breakers in substation 2 fail to operate due to a battery failure (Figure 1). This results in an outage for customers served by substations 1, 2, and 3 on the LUA system. Figure 1 C. Post-Event Facts Immediately after the outage, LUA customer service receives numerous customer calls followed by a call from its Public Utility Commission/Local Utility Board ("PUC/LUB"). LUA dispatches crews immediately after being informed of the outage to identify and resolve the problem. Within 45 minutes, the fault is sectionalized and the all load is restored. The PUC/LUB receives complaints from LUA customers who identify economic and other adverse impacts of the outage. The PUC/LUB demands a report from the LUA that describes the event and restoration, as well as potential solutions. LUA submits a report which finds that the main solution to this problem involves the implementation of a SCADA system. The SCADA system scope of work includes battery voltage telemetry and would have identified the DC system issue and prevented the protection system failure, resulting in only the loss of substation 3. The SCADA plan cost estimate is $30 million and was presented three years earlier. The PUC/LUB evaluated the costs and benefits of the new SCADA system, but did not approve the project in order to reduce the budget and/or provide rate stability for the struggling local economy. LUA, the PUC/LUB, and customers will re-evaluate the merits of adding SCADA as well as other solutions such as increasing substation inspection runs, updating the battery fleet, and further investigating battery manufacture reliability records. Based on the LUA report, the battery bank failure rate immediately after routine inspections is expected to occur once every 3,500 years. Seventy battery banks are used on the LUA system, so a bank failure should be expected every 50 years. BES Company's neighboring 230kV and 500kV system does not experience an adverse system impact. Subsequently, BES Company identifies that one of its breakers operated at the LUA South POD. BES Company and LUA coordinate a review of the system protection scheme and BES Company determines that it operated correctly. BES Company verifies that the LUA outage did not create any thermal, voltage, or transient stability limit violations on the BES Company system. The Regional Entity, NERC, and FERC treat the outage as a Reliability Standards issue. The LUA System (highlighted in yellow) is considered part of the BES because it meets the "bright line" 20 MVA and 100 kV thresholds under the current BES definition and the NERC Statement of Compliance Registry Criteria ("SCRC"). The event would most likely be considered a TPL-003 category C event specifically C8 SLG Fault, with delayed clearing that may include a stuck breaker or protection system failure. The LUA Substation Department reviews its inspection records and has adequate documentation for the battery banks involved in the outage. As a result, LUA avoids substantial fines. However, during the inspection review, LUA notices that the battery bank in a similar distribution substation inspection schedule was completed three days late. Upon following further internal procedures, LUA finds that the battery bank was inspected three days late due to restorations efforts after a major wind storm. Although there were no LOS impacts, and the inspection schedule was unrelated to the outage, the Reliability Standards triggered a LUA self report to its Regional Entity which ultimately resulted in a $50,000 penalty. D. Summary This example identifies that in addition to a “bright line” BES exclusion process a more refined process such as a “performance based” reliability assessment is needed to distinguish BES facilities from distribution facilities if the NERC Statement of Compliance Registry Criteria (“SCRC”) continues to be the benchmark for assessing BES facilities. It is clear from this example that the current 100 kV and 20 MVA thresholds cannot accurately classify what is and is not considered part of the BES. Defining BES facilities is important from the “Reliability Standard” and “LOS” perspectives as well as from a local and regional jurisdictional standpoint. There are multiple agencies identifying and approving what facilities should and should not be built, what programs should and should not be implemented, and if a fine should be paid by customers experiencing an outage without determining if it could have had an adverse impact on neighboring electric systems. Without a performance-based process, many small and medium electric utilities would be unnecessarily burdened. IV. Neighboring System Rule It is important but not always easy to distinguish the difference between “reliability” and “LOS” impacts. One way to resolve this is to use the “neighboring system rule.” Simplistically, if events on the host system’s facilities can create an “adverse” or “material” impact on a neighboring electric (TO, TOP, BA) system, those facilities should be considered part of the BES as they are creating a reliability impact. If not, these facilities should not be considered part of the BES. V. “Adverse” or “Material” Impact A key question in applying the “neighboring system rule” is what is an “adverse” or “material” impact, and what “performance based” assessment should be used to benchmark adverse or material. Because the electric system within an interconnection is frequency interdependent, theoretically every system change impacts the interconnected system to some degree. Turning on a light-switch that is connected to an operational 20 watt CFL (light bulb) theoretically impacts frequency, although to an undetectable degree. Therefore the term “material” or “adverse” impacts must be defined to distinguish observable impacts that affect reliability from minutia. A number of performance-based exclusion examples have been proposed that use Power Transfer Distribution Factors (“PTDF”), Line Outage Distribution Factors (“LODF”), fault duty or short circuit levels, reactive margin studies (P-V and Q-V), abbreviated or focused powerflow and transient stability analysis, as well as complete TPL assessment using multiple seasonal base cases, loading conditions, transfer levels. These methods demonstrate various metrics, they rank system strength (both real and reactive), the ability of power to flow through system under normal and outage conditions, and they determine steady state, voltage stability and transient (angular) stability performance. Although there may be advantages to a multi-step “performance based” approach that includes the exclusion examples above, this paper proposes a TPL-based assessment that is consistent with BES performance benchmarks used in assessing transmission system performance in North America. The Western Electricity Coordinating Council (“WECC”) BES Exclusion/Inclusion Assessment – 2-16-11 version provides sound metrics in assessing the performance of a system as well as determining if a system can materially impact a neighboring system (Figure 2). It would be envisioned that each interconnection would develop a “Disturbance Performance Table of Allocable Effects on Other System”. This table is necessary because the NERC TPL Performance Table does not provide actual performance details on acceptable transient and post transient voltage perturbations or minimum transient voltage frequencies. Figure 2 show the approved TPL-001 through TPL-004 performance tables. Figure 3 - Table 1 from the NERC TPL Reliability Standards VI. Performance Based Assessment Process The “performance based” methodology below is based on the “neighboring system rule” and the WECC BES Exclusion/Inclusion Assessment – 2-16-11 that was developed by the WECC Bulk Electric System Definition Task Force (“BESDTF”). The process focuses on exclusions rather than inclusion and specific response times, schedules, and process details have been removed as this will likely need to be determined by each Regional Entity Representing the Interconnection (“RERI”) A. Purpose The purpose of this document is to set forth a “performance based” technical process for assessing whether elements with a nominal operating voltage greater than 100 kV and outside the NERC SCRC based excursion process should be excluded from the Bulk Electric System. An element is necessary to reliably operate an interconnected transmission system if it significantly affects neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1 below. This paper proposes a method for assessing whether an element is necessary to support the reliability of an interconnected transmission system or if the element is limited to supporting local customer service levels. B. Terms Exclusion Assessment (EA) An assessment of whether a Subject Element or System has a material impact on neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1 below and conducted in accordance with the process set forth in this document. EA Base Case The interconnection approved, Base Case as modified to include the Subject Element, used to perform the assessment described in this document. Regional Entity Representing the Interconnection The regional entity representing the interconnection Registered Entity The entity registered to comply with mandatory reliability standards for a Registered Function. Responsible Entity The entity responsible for performing the EA and verifying the results of the EA to the interconnection. Subject System or Element of a System The System or Element of a System that is being examined by the EA. C. Applicability a. An EA may be performed: i. By a registered entity, or by a third party on behalf of a registered entity, to assess whether a Subject Element or system has a material impact on neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1 may be excluded from the BES as set forth by the RERI. ii. The RERI, or by a third party on behalf of the RERI, to assess whether a Subject Element or system has a material impact on neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1 should be included as part of the BES as set by the RERI. b. Frequency of analysis. The confirmed findings of an EA are valid until reversed by a subsequent EA. A new EA is required if: i. Significant changes are made to the network topology in the vicinity of the Subject Element; or ii. RERI staff requests a new EA. Such request shall be provided in writing and shall include reasonable justification for the request. D. Notifying the RERI of the Responsible Entity's intent to submit an EA finding or to perform an EA. The Responsible Entity shall notify the RERI in writing of its intent to submit such a finding. Such notice shall include: a. A general description of the Subject Element(s); b. One-line diagrams representing the Subject Element and applicable neighboring Elements; and c. A description of the base case that will be used in performing the EA and how that case will be stressed for the analysis. E. Performing the Analysis Base Case The base case(s) used for the studies shall be developed from current interconnection Operating Cases and shall simulate stressed conditions in the area of the element to be analyzed which (1) are reasonably expected to be achieved, consistent with the study period selected (e.g., hydro generation shall reflect seasonal water availability patterns) and (2) are expected to provide "worst-case" results (i.e., the greatest impact on voltage, flow, or transfer capability) during the upcoming operating year. The base case(s) shall be "stressed" by committing or de-committing generating units and adjusting generating unit output to increase the flow on the candidate element and the electrically nearest rated interconnection transfer path to the greatest extent possible, but not beyond their continuous ratings, for the initial set of conditions. To help minimize the possibility of dispute as to whether the base case(s) are suitably stressed, entities are encouraged to solicit input from subregional planning groups or other planning entities as the suitability of the base case(s) before undertaking the analyses described below. i. Non-represented Elements. If the Subject Element is not represented in the EA Base case: 1. The Responsible Entity shall provide to the RERI a written request to add the Responsible Entities data to the cases: o all data reasonably necessary to accurately and completely model the Subject Element in the EA Base case; and o A one-line diagram showing this element and other nearby Elements. If the nearest connected Element is not found to be necessary for the operation of an interconnected transmission system, the RERI shall notify the Responsible Entity to take no further action. F. Performance Based Methodology The impact an System or Element has on neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1 shall be determined by assessing the performance of key measures of BES reliability through power flow, post-transient, and transient stability analysis with (1) the system, and the Subject Element, operating at reasonably stressed conditions that replicate expected system conditions under which the loss of the Subject Element would have the greatest impact on the key measures of reliability, and (2) the Subject Element removed from service, but without allowing for system readjustment. For the purposes of this analysis, "Elements" may be: (1) lines; (2) transformers; (3) buses or bus sections; (4) generating units; (5) shunt devices . i. Simulation 1: Requirement: Meet applicable NERC Reliability Standard (TPL-002 and TPL-003) and the RERI Disturbance Performance Table of Allocable Effects on Other System" Criteria performance for NERC TPL-002 and TPL-003 disturbances. Step 1: Run appropriate TPL-002 (N-1 contingency) studies of elements in the electrical vicinity of and including the Candidate Element (i.e., simulate primary protection operates as intended) Step 2: Run appropriate TPL-003 (N-2 contingency) studies of elements in the electrical vicinity of and including the Candidate Element. This would include both N-2 contingencies in which the Candidate Element would simultaneously be lost as part of a common mode failure, as well as contingencies in which the Candidate Element's primary protection fails. Automatic Remedial Action Schemes ("RAS") or Special Protection Schemes ("SPS") that are fully redundant (i.e., their failure is not credible) may be triggered during this simulation. If the failure of the RAS/SPS is a credible event, it should be considered as part of the N-2 analysis. ii.

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| Simulation 2: Requirement: Remove the Candidate Element. Do not allow for system adjustment, and re-solve the base case. Then conduct applicable NERC Reliability Standard (TPL-002 and TPL-003) contingencies. Step 1: Remove Candidate Element (i.e., simulate unplanned opening of facility). Step 2: Assume no system adjustment. At this point, elements may be loaded above their continuous ratings but may not be loaded above their emergency ratings. Step 3: Perform NERC TPL-002 and TPL-003 (N-1 and N-2 contingency) studies. Step 4: If the analysis demonstrates performance that meets or exceeds that called for in the NERC Reliability Standards and RERI System Performance Criteria, the Candidate Element would be determined to not be necessary for the operation of an interconnected transmission system. Note: Consequential load tripping is allowed, and consequential and out-of-step generation tripping is allowed. Criteria Table 1: RERI Disturbance-Performance Table of Allowable Effects on Other Systems NERC and WECC Categories Outage Frequency Associated with the Performance Category (outage/year) Transient Voltage Dip Standard Minimum Transient Frequency Standard Post Transient Voltage Deviation Standard A System normal Not Applicable Nothing in addition to NERC B One element out-of-service ≥ 0.33 Not to exceed 25% at load busses or 30% at non-load busses. Not to exceed 20% for more than 20 cycles at load busses. Not below 59.6Hz for 6 cycles or more at a load bus. Not to exceed 5% at any bus. C Two or more elements out-of-service 0.033 – 0.33 Not to exceed 30% at any bus. Not to exceed 20% for more than 40 cycles at load busses. Not below 59.0Hz for 6 cycles or more at a load bus. Not to exceed 10% at any bus. D Extreme multiple-element outages < 0.033 Nothing in addition to NERC Figure 1. Voltage Performance Parameters RERI TPL criteria related to reactive power resources: 1. For transfer paths, voltage stability is required with the pre-contingency path flow modeled at a minimum of 105% of the path rating for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the pre-contingency transfer path flow modeled at a minimum of 102.5% of the path rating. 2. For load areas, voltage stability is required for the area modeled at a minimum of 105% of the reference load level for system normal conditions (Category A) and for single contingencies (Category B). For multiple contingencies (Category C), post-transient voltage stability is required with the area modeled at a minimum of 102.5% of the reference load level. For this criterion, the reference load level is the maximum established planned load limit for the area under study. 3. Specific requirements that exceed the minimums specified in 1 and 2 may be established, to be adhered to by others, provided that technical justification has been approved by the RERI. 4. Item 3 applies to internal interconnection Systems. Submitting a Proposed Finding of Exclusion to the Regional Entity Information required. Once the analysis has been performed and the Subject Element/System has been determined to not have a material impact on neighboring Transmission Owners, Operators, and Balancing Authorities as described in Table 1, and is unnecessary for the operation of an interconnected transmission system, the Responsible Entity shall submit the findings to the RERI. RERI Review of Proposed Findings The RERI operational/planning staff with technical expertise in powerflow studies shall review Proposed Findings of Exclusion submittals and shall determine if the assessment is deficient or agrees with the finding of exclusion. The RERI shall exempt the system elements from the BES, if the elements are approved for exclusion. If the exclusion of the BES elements change the Responsible Entities NERC functional registrations the Region shall support the Responsible Entity through the NERC deregistration process. Dispute Resolution A Responsible Entity or Registered Entity or Owner may appeal a Disputed Finding of Exclusion with the RERI to NERC. Ongoing Responsibilities a. Logging. The RERI shall create and maintain a comprehensive list, available for public review, of: i. All Elements with nominal operating voltages at or above 100 KV that have Confirmed Findings of Exclusion, or, through other aspects of the BES definition, have been excluded from the BES including an explanation of how the element was excluded through the definition; ii. All Elements with nominal operating voltages below 100 kV that have Findings of Inclusion; and iii. The status of all EAs in dispute. iv. The Responsible Entity would continue to provide system data to the neighboring Balancing Authorities and Transmission Owners and Operators and if applicable continue to coordinate underfrequency load shed and under voltage load shed scheme information. VII. Conclusion NERC should adopt the TPL-based assessment as proposed herein. A bright-line BES test will not exclude all load distribution facilities as required by the FPA. Further, a performance-based exemption process would be objective, consistent, and transparent, and would adequately differentiate between local distribution and transmission, i.e., BES, facilities. |
| No |
| We believe the “contiguous BES” debate is largely a red herring. The central questions the SDT should be focusing on are those that must be answered to comply with the statute, namely whether the |

specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get seriously off course by focusing on a question with no statutory basis – whether the BES should be “contiguous” – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either “contiguous” or “non-contiguous,” but it will have met the relevant statutory criteria. At the same time, by including only those facilities in the BES that are necessary to operate the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the “contiguous/non-contiguous” question directly, but should focus on the question of what facilities are “necessary” for the operation of the bulk system, and let results speak for themselves on the “contiguous/non-contiguous” question. We also note that the “contiguous/non-contiguous” question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires “users” of the BES to comply with reliability standards, as well as “owners and operators” of BES facilities. Accordingly, as long as it can be demonstrated that it is “necessary for” users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC’s Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the “GO-TO Task Force”) have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a “contiguous” BES is necessary so that the dedicated interconnection facilities connecting BES generators to the bulk transmission system must also be classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities “are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system.” White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Requiring Generation Owners and Operators to comply with the same standards as BES Transmission Owners and Operators “would do little, if anything, to improve the reliability of the Bulk Electric System,” especially “when compared to the operation of the equipment that actually produces electricity – the generation equipment itself.” Id Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as “Transmission” and classified as part of the BES in order to make reliability standards effective, even where it interconnects a large BES generator. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a “contiguous” BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, this would require large segments of the nation’s distribution systems to be defined as BES. This would squarely violate the

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| FPA, which unequivocally requires “facilities used in the local distribution of electric energy” to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It is also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as “users” of the transmission system, may be required to set, test, and maintain their UFLS and UVLS protection systems in accordance with norms set by the relevant RE as a condition of using the bulk transmission system because proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without exposing the distribution provider to unnecessary compliance costs. A contiguous BES definition, on the other hand, could inappropriately expose many distribution providers to compliance with standards that are appropriate only for owners and operators of bulk transmission facilities, resulting in substantially increased compliance costs with no benefit to reliability. |
| Yes |
| As noted above, the NERC GO-TO Task Force has performed an extensive technical analysis that is relevant to the contiguous BES issue. See White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf); Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). |
| No |
| SNPD notes that there are significant differences between the question presented in the “Scope” statement at the top of the response form, the SAR document, and the issue as presented in Question 4. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which ‘supports’ the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, SNPD opposes including this question in Phase II because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power.” 16 U.S.C. § 824o(a)(1). If the issue is one of whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and this aspect of the SAR should be rejected. On the other hand, as presented in the SAR itself and in Question 4, the question is whether there is technical justification for “including in the BES definition the equipment which ‘supports’ the reliable operation of the BES.” In this formulation, the question does not contemplate the obvious statutory violation of classifying facilities used in local distribution as part of the BES. SNPD is nonetheless concerned that the question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. Finally, we note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to Reliability Standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
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| SNPD, and many other entities, especially (but not exclusively) from the WECC region, have from the beginning of the BES definition process maintained that 200 kV rather than 100 kV should be the blackline threshold. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition's inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities, SNPD believes there is no technical justification for including facilities operating at 100-kV in the BES. SNPD therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. In our response to Question 7(a), we briefly describe some of the historical and technical data that supports re-examination of this issue. We note, further, that differences between the Eastern Interconnection and the Western Interconnection may well justify a different threshold for the two interconnections. There are several differences between the two interconnections that may justify different treatment. For example, the Western transmission system generally links isolated generators with load centers that are located far from the generator using long transmission lines, while generation and load in the Eastern system are usually much closer geographically and the system is therefore much more networked. In addition, the Western system is generally stability-limited, while the Eastern system is generally thermally-limited. And the Western system uses a path rating approach while the Eastern system uses a flow-based approach. |
| Yes |
| In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100-kV or 200-kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend its work to the SDT as a good starting point for its Phase II analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase II in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: "In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200 kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230 kV, 345 kV, and 500 kV as typical bulk transmission voltages." Facilities operating below 230 kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: "These 100-200 kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100 kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas." The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230 kV or above. "It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100 kV and 200 kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200 kV or higher voltage." The BESDTF backed up these observations with technical |

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| analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 “Transfer Paths,” the majority of which are operated at voltages exceeding 200 kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200 kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200 kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: “As can be seen, the nominal average capacity of lines below 200 kV is significantly below that of the 200-300 kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines.” In short, the available evidence demonstrates that most transmission elements in the Western Interconnection operate at voltages above 200 kV, while lines operating in the range of 100-200 kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100-kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200-kV threshold with an inclusion mechanism to identify the minority of 115-kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| SNPD is concerned that the Local Network (“LN”) exclusion in the BES Definition resulting from the Phase I Standards Development process contains an unnecessary limitation requiring that power “flows only into the LN.” SNPD believes that, as long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system (that is, “the LN does not transfer energy originating outside the LN for delivery through the LN”), the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in inconsequential amounts or only during unusual contingencies. SNPD supports technical analysis of this issue in order that this flaw in the BES Definition can be corrected on the basis of a technical record. While we support technical analysis of this issue, we are concerned that the reference to “certain conditions” suggests that the technical analysis will not focus on LNs operating as intended, but will delve into contingencies, even contingencies that are extremely remote. We urge the SDT to analyze this question for LNs operated as intended under normal conditions. If, in unusual circumstances, flows might emanate from an LN that do not emanate under normal circumstances, the relevant RE, TOp, or RC can use the Inclusion process to seek inclusion of that LN in the BES if it can demonstate the LN has a substantial impact on operation of the bulk transmission system under reasonably foreseeable contingencies. |
| No |
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| Yes |
| As noted in our response to Question 1, we agree that Phase II should address the question of defining the points of demarcation between the BES and non-BES Elements. This is a critical question for clearly defining the compliance obligations of Registered Entities. We believe that demarcation is a technical question, and therefore believe Phase II should approach demarcation as a technical question rather than as merely a clarification. If the SDT puts together a technical record supporting its approach to demarcation, we believe the resulting standard will be more likely to survive regulatory review. We again note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. We also believe that additional work is necessary to define the relationship between the Exclusions and Inclusions. Some of the Inclusions and Exclusions as currently drafted provide language that explains how they operate if an Element falls into both an Exclusion and Inclusion. For example, Inclusion I1 specifies that certain transformers must be included in the BES “unless excluded under Exclusion E1 or E3.” This makes clear that transformers operating within a radial or Local Network subject to exclusion under E1 or E3 are not part of the BES |

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| even if they otherwise would be included as a result of Inclusion I1. We are concerned, however, that there is no clear general rule on how to classify an element that meets both an Inclusion and an Exclusion. For example, a capacitor located on a radial line, and therefore excluded by operation of Exclusion E1 might nonetheless meet the requirements for inclusion under Inclusion I5. A method for resolving this conflict should be spelled out in the definition so that future disputes about conflicting Inclusions and Exclusions can be avoided. As a starting point, we suggest that the phrase at the end of Inclusion I1 ("unless excluded under Exclusion E1 or E3") be added to Inclusions I4 and I5, so that all non-generation equipment that is located on a radial or in a LN is excluded consistent with the intent of Exclusions E1 and E3. Similarly, the phrase "unless excluded under Exclusion E2" should be added at the end of Inclusion I2 so that definition makes clear that customer-owned, behind-the-meter generation is always excluded under Exclusion E2. While the relationship between the Inclusions and Exclusions might reasonably be viewed as just a clarification of the current definition, we note it in response to this question because we believe additional technical analysis may be needed to resolve potential conflicts between Inclusions and Exclusions, at least in some circumstances. In addition, we suggest that the SDT prepare flow-through diagrams that graphically represent how particular Elements will be handled under the BES Definition, both as a matter of guidance to regulated entities and as a means of identifying potential conflicts between Inclusions and Exclusions that should be addressed by the SDT. |
| Yes |
| As reflected in our response to Question 1, SNPD is concerned that the broad language of the Phase II SAR creates the danger of "mission creep" that would allow a wholesale revisiting of questions decided in Phase I. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase I, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. If there is near-unanimous agreement that these clarifications should be addressed in Phase II, we recommend the following clarifications: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100 kV or higher, we suggest certain clarifying langauge. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100 kV or above, which is why the definition uses the word "and" ("the primary and secondary terminals"). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT's intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: "Transformers with primary terminals that operate at or below 100 kV are not part of the BES. Transformers with no secondary terminals operating at or above 100 kV are also excluded from the BES." This language will help ensure that there is no controversy over whether the SDT's use of the word "and" in the phrase "the primary and at least one secondary terminals" was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing ". . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above" so that the Inclusion covers transformers with terminals "connected at a voltage of 100 kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100 kV or above." 3) With respect to Inclusion I4, which addresses dispersed power producing resources, we suggest adding at the end of the Inclusion the phrase ". . . unless the dispersed power producing resources operate within a Radial System meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E3." This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a Radial System or Local Network serving retail load would not convert the Radial System or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, SNPD is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. SNPD believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase II process. 5) With respect to Exclusion E1, which covers Radials, we believe |

two changes would greatly improve the clarity of the language. First, the term “transmission Elements” in the initial paragraph should be changed to “Elements.” Radial systems are not transmission systems and including the word “transmission” in the Radial System exclusion is therefore unnecessary and confusing. Second, the “Note” at the end of the exclusion states that “a normally open switching device between radial systems” will not serve to disqualify the Radial from exclusion under Exclusion 1. While SNPD strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: "Normally-open switching devices between radial elements does not affect this exclusion." This will make clear that a radial with more than one normally-open switch connecting it to another radial is still a radial. From the perspective of the BES Definition, the key question is whether switches operating between Radials are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather than a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, SNPD is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a Radial System or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to Radial Systems, the appearance of behind-the-meter generators could cause the Radial System to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the Radial System owner. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (“LN”) exclusion, Exclusion E3, SNPD believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100 kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. SNPD also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. We also suggest that subparagraph (b) of Exclusion 3 could be more clearly drafted. Subparagraph (b), as part of the requirement that power flow into a LN rather than out of it, includes this description: “The LN does not transfer energy originating outside the LN for delivery through the LN.” We understand this language is intended to distinguish a LN from a link in the transmission system – power on a transmission link passes through the transmission link to a load located elsewhere, while power in a LN enters the LN and is consumed by retail load within the LN. While we agree with the concept proposed by the SDT, we believe the language would be clearer if it read: “The LN does not transfer energy originating outside the LN for delivery through the LN to loads located outside the LN.” We believe the added language is necessary to distinguish between a transmission system, where power that originates outside a system is delivered through the system and passes through the system to a sink located somewhere outside the system, from a LN, in which power originating outside the LN passes through the LN and is delivered to retail load within the LN. To put it another

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| way, the italicized language helps distinguish a transmission system from an LN, in which the LN "transfers energy originating outside the LN for delivery through the LN to loads located within the LN." Finally, SNPD believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system |
| No |
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| No |
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| Individual |
| Robert Ganley |
| LIPA |
| No |
| • Delete the following scope element: "Determine if there is a technical justification to support an automatic interrupting device in Exclusions E1 and E3." The question of including automatic interrupting devices was addressed by the Phase 1 SDT, and does not need to be revisited. • Delete the following scope element: "Determine if there is a technical justification to support the inclusion of Cranking Paths and Blackstart Resources" for the same reasons as stated in the preceding bullet. "Cranking Path" is already a defined term in the NERC Glossary and the requirement for Transmission Operators to document Cranking Paths is already stipulated in EOP-005. |
| Yes |
| Resources greater than a certain threshold should be classified as BES elements. The threshold need not be a fixed MVA level, but could be either fixed, per unit, or on a system percentage basis, as may be appropriate and technically justified. |
| No |
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| Yes |
| The contiguous issue was never resolved in Phase 1. |
| No |
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| No |
| However, if considered it should be limited to a simple and not a complex justification with an idea that BES support elements will only be required to comply with a smaller subset of reliability standards. |
| No |
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| No |
| Phase 2 should not attempt to examine every attribute of BES definition that is currently posted for approval. The SDT has already discussed the technical concepts in its Phase 1 deliberations. |
| No |
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| No |
| Phase 2 should not attempt to examine every attribute of the BES definition that is currently posted for approval. Blackstart requirements regardless if they are BES or not are covered in Reliability Standards. The SDT has already discussed the technical concepts in its Phase 1 deliberations. |
| No |
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| Yes |

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| The 100 kV brightline is a fundamental, but technically unsupported, assumption in the BES definition. Technical justification for the 100 kV must be developed in Phase 2, as it is listed in the scope above. |
| No |
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| Yes |
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| No |
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| Yes |
| The main paragraph and items E3b and E3c of Exclusion E3 adequately defines a Local Network. It seems like the overall intent is to exclude non bulk local network systems but they potentially would still be included because of E3a. E3a should be eliminated. If not eliminated, the term “underlying elements” must be clearly defined and there should be a technical justification for the MVA threshold level. |
| No |
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| No |
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| Yes |
| Any changes to BES definition will have a direct impact on many of our business practices. |
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| Individual |
| Curtis Klashinsky |
| FortisBC |
| No |
| We do not agree with the entire scope as put forward. The SAR as written suggests that Ph2 SDT should undertake the reexamination of the entire BES definition. It extends to every attribute of the definition, including the 100kV Bright-line. We believe that it is out of the scope of the Ph2 SDT to reassess and challenge the 100kV Bright-line along with every deliberation of the Ph1. We believe that SDT has done an excellent job in Ph1 and made an excellent decision to park 2-3 items for further assessment in Ph2. SDT has already discussed all the technical concepts in its Ph1 deliberations. Accordingly, we only support technical justification and reassessment of a select group of 2-3 items. There is no need to assess in attempt to justify each and every part/attribute of BES definition that has just been approved by the NERC BOT and filed with FERC for approval. |
| Yes |
| Yes. We also believe that technical justification process should categorize resources into one of the following categories. Elements would be categorized on a technical basis to justify the extent of applicability of the reliability standards. - Resources less than a certain threshold should be classified as BES support elements, including “must run” units and blackstart, and be only required to adhere to a small and relevant subset of reliability standards. - Resources greater than a certain threshold should be classified as BES elements and be required to adhere to all relevant reliability standards. |
| Yes |
| We believe that a SDT sub-team took upon this task and have some excellent information and analysis that should be an input or starting point. |
| No |
| As stated earlier, we do not support that Ph2 should undertake the reexamination of this attribute of BES definition that has just been approved by the NERC BOT and will provide little if any value in this exercise. We believe that this issue is and can be addressed for unique and individual cases as for most part BES system will be contiguous. If and when a non-BES and non-contiguous subsystem needs to be contiguous for BES reliability, it can be addressed by the exception process. |
| No |

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| Yes |
| We only support this with an expectation that this will be a simple and not a complex justification. The outcome of this exercise should be that BES support elements will ONLY be required to comply with a smaller subset of reliability standards. This should not put undue burden on the entities for compliance of BESS (BES Support) elements. |
| No |
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| No |
| SDT has already discussed the technical concepts surrounding “automatic interruption devices” (AID) in its Ph1 deliberations. Further, any “tap” without AID can be designated as BES through the exception process if it has an impact on the reliability of the interconnected BES. Accordingly, there is no need to further assess this attribute of BES definition that has just been approved by the NERC BOT and filled with FERC for approval. We need to wait and learn over the next 3-5 years after current definition is implemented. |
| Yes |
| Technical justification was already discussed by the SDT in its Ph 1 deliberations. |
| No |
| We do not support that Ph2 should undertake to reexamine this attribute of BES definition that has just been approved by the NERC BOT. SDT has already discussed the technical concepts in its Ph1 deliberations. Further, Blackstart requirements are already covered in Reliability Standards regardless of whether the resource is BES or not. There is no need to discuss every part/attribute of BES definition that has just been approved by the NERC BOT and filed to FERC for approval. We need to wait and learn from experience over the next 3-5 years after current proposed definition is implemented. |
| No |
| SDT has already discussed the technical concepts in its Ph1 deliberations. |
| No |
| We believe that this is out of scope of SDT unless there is a direct Regulatory Order to do so. Accordingly, we do not support that Ph2 should undertake to examine the voltage threshold for BES that has just been approved by the NERC BOT and filed with FERC for approval. NERC needs to wait and learn from experience over the next 3-5 years after current proposed definition is implemented. |
| No |
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| Yes |
| Yes, SDT should pursue this and BES definition should allow for some minimal power flow out of the local network that will NOT have an adverse impact on the reliability of the interconnected BES. |
| No |
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| No |
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| No |
| See above. If Phase 2 intends to open and reassess the entire definition then we suggest that Phase 1 work should be remanded. |
| No |
| If there are any regional variances they can/should be handled through the exception process. |
| Yes |
| We are not clear on what exactly is being asked. However, this is a fundamental change that will impact many entities across the NERC foot print and require many changes to the business practices along with incremental costs for most if not all entities. |
| As mentioned above, we only support to assess and justify couple of the major items in Ph 2 at this stage. Ph 1 work has been just approved by the NERC BOT and filed with FERC. It has yet to be |

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| implemented by the industry and lessons are yet to be learned by all stakeholders including NERC. NERC needs to wait and learn from experience over the next 3-5 years after current proposed definition is implemented to further assess other attributes of the definition. As part of this process, NERC should take the opportunity to enhance the Applicapability Section of the standards to ensure that it clearly identifies the elements that the standard applies. |
| Individual |
| RoLynda Shumpert |
| South Carolina Electric and Gas |
| Yes |
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| Yes |
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| Yes |
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| Yes |
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| Individual |
| Martin Bauer |

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| US Bureau of Reclamation |
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| Yes |
| Some additional text should be considered to ensure the Transformers listed in I1 cannot be confused with the generator step up transformer in I2. The technical justification for BES definition should be supported with load flow studies to ascertain reliability impacts on major or critical transmission paths. The technical justification for contiguous BES definition will probably result in a non contiguous definition, which is probably more realistic considering the variation in contingencies within interconnected power systems and the potential reliability impact of BES Elements of different sizes, even within WECC. |
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| No |
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| Individual |
| Diane Barney |
| New York State Dept. of Public Service |

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| No |
| The New York State Department of Public Service (NYSDPS) believes that the scope of the project should be to provide technical justification to retain or revise both the core definition of the Bulk Electric System (BES) and the inclusions and exclusions indentified in Phase 1 of the project. The structure of some questions seems to adopt the existing definitions as given and only seeks technical justification to revise them. The NYSDPS believes that the scope should also include the development of technical justifications to support current definitions. The NYSDPS is also concerned that the scope could have legal implications in areas where the scope seems to be leading to revisions to the BES definition where it could expand to include facilities used in the local distribution of electric energy. |
| No |
| This question should be re-worded to, “Do you agree that the SDT should pursue the development of technical justification to set thresholds for Real and Reactive Power Resources used in the reliable operation of the BES?” Any technical analysis should evaluate the costs associated with potential increases in the number of facilities for which NERC compliance would be required to the potential reliability benefits expected. In addition, the threshold set should not include any facilities used in the local distribution of electric energy. |
| No |
| Development of technical justifications to support the BES definition will likely require a nationwide study to be conducted by NERC. |
| No |
| The assumption that there is a reliability benefit of a contiguous BES is an inappropriate bias. It is likely that there will be negative reliability impacts on local distribution system which would not be idenfitied as the question is currently worded. The focus should be on if there is a need for a contiguous BES. In any event, if intervening facilities needed for a contiguous BES are part of the local distribution system, they are not legally eligible to be designated as BES. The NYSDPS suggests that a methodology should be developed to distinguish between elements of the BES over which standards will apply to directly and non-BES elements which can cause a major disruption on the BES for which standards must be developed to demonstrate that those major disruptions will not occur. |
| No |
| Development of technical justifications to support the BES definition will likely require a nationwide study to be conducted by NERC. |
| No |
| Please see the response to question 3 to the extent that this question seems to be trying to identify support equipment for a contiguous BES. Regarding system facilities that can have a major negative impact on the bulk system, the NYSDPS believes that the focus should be on requiring a demonstation that these facilities will not create a major BES disturbance rather than trying to directly control these facilities. |
| No |
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| Yes |
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| No |
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| Yes - Blackstart Resources; No - Cranking Paths Technical justification should be pursued to support the inclusion of Blackstart Resources in the BES definition. Cranking Paths should not be included in the BES definition because reliability could be undermined; it is likely that utilities would document only one cranking path in order to minimize compliance requirements when this is one area where the flexibility of several paths is desired. The NYSDPS is also concerned about legal implications if the revisions sought here could potentially include facilities used in the local distribution of electric energy. |
| No |
| Development of technical justifications to support the BES definition will likely require a nationwide study to be conducted by NERC. |
| Yes |

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| The NYSDPS strongly agrees that technical justification should be pursued for the designation of 100 kV as the bright-line voltage level - along with any other appropriate alternative designation - that may provide better reliability and/or a lower cost. Any technical analysis should evaluate and compare the costs associated with potential increases in the number of facilities for which NERC compliance would be required to the potential reliability benefits expected. The NYSDPS also believes that classification of BPS elements by voltage level is arbitrary and urges that strong consideration should be given to the findings in the NPCC and NERC September 21, 2009, compliance filing with FERC in Docket No. RC09-3-000 in which it was stated that "In general, NPCC concluded that application of the developed BES bright-line definition within NPCC would increase the number of facilities for which NERC compliance would be required, resulting in economic and resource impacts without identified increases in the overall reliability of the NPCC international, interconnected power system." This type of analysis could be conducted in the other regions to determine if this approach to designating the BES provides reliability at a lower cost. |
| Yes |
| See the NPCC study presented in the NPCC/NERC 9/21/09 filing in FERC Docket No. Rc09-3-000. Development of technical justifications to support the BES definition will likely require a nationwide study to be conducted by NERC. |
| Yes |
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| No |
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| Yes |
| The NYSDPS strongly believes that technical justification should be pursued for selecting any threshold used in the BES definition including the thresholds associated with generating resources identified in inclusion I2. |
| Yes |
| Regarding improving the clarity of the relationship between the BES definition and the ERO Statement of Compliance Registry Criteria established in FERC Order 693, the relationship should establish that the definition of the BES is the foundational standard upon which designations in the Compliance Registry are made. In addition, for the item "The appropriate 'points of demarcation' between Transmission, Generation, and Distribution" the word "Distribution" should be changed to "Local Distribution" per the language in the FPA. |
| No |
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| Yes |
| In general, business practices will need to be modified whenever there is a change in operating procedures and often impact consumers. |
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| Individual |
| Anthony Jablonski |
| ReliabilityFirst |
| Yes |
| ReliabilityFirst agrees with the scope, but it is unclear what types of data/information the SDT will be collecting to perform the associated technical justifications. |
| Yes |
| In regards to the threshold, the SDT should justify both the Real and Reactive Power thresholds along with any connection voltage thresholds. For example, it may be appropriate for a 300 MVA generator connected to the 69 kV system to be considered part of the BES. |
| No |
| ReliabilityFirst suggests the SDT reach out to the planning type entities (PC, TP, etc.) for this type of information. |
| No |
| From a reliability standpoint, it is unclear how the BES could be operated in a non-contiguous |

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| manner. Based on the ReliabilityFirst staff engineering judgment, the BES must be contiguous to be operated reliably. |
| No |
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| No |
| ReliabilityFirst seeks further clarification of the meaning of the term “supports” along with what types of equipment is being referred to. |
| No |
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| Yes |
| Automatic interrupting devices should be mentioned in Exclusion E1 and E3 to clearly specify what facilities make up the BES. Engineering logic dictates that radials and Local Networks should be able to be isolated from the BES by automatic interrupting devices so as those radials and Local Networks may not cause an outage on a BES Element. |
| No |
| ReliabilityFirst suggests the SDT reach out to the planning type entities (PC, TP, etc.) for this type of information. |
| Yes |
| From a reliability standpoint, it is unclear how a Blackstart Resource could be included as part of the BES but the cranking path would not be included as part of the BES. Based on the ReliabilityFirst staff engineering judgment, the Blackstart Resource and its associated cranking path must be contiguous with the BES to be operated reliably. |
| No |
| ReliabilityFirst recommends the SDT reach out to the planning and operating type entities (PC, TP, TOP, etc.) for this type of information. |
| No |
| Within the ERO enterprise, the 100 kV voltage level has been the accepted voltage level for defining the BES. |
| No |
| ReliabilityFirst recommends the SDT reach out to the planning type entities (PC, TP, etc.) for this type of information. |
| Yes |
| Clear criteria needs to be defined for certain conditions, flow and time. |
| No |
| ReliabilityFirst recommends the SDT reach out to the planning type entities (PC, TP, etc.) for this type of information. |
| Yes |
| See comments submitted in questions one through eight. |
| No |
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| No |
| Without seeing the technical justifications or proposed revisions to the BES definition, it is very hard to envision any regional variances which may be needed as a result of this project. |
| Depending on the outcome of this project, it would most likely have an effect on stakeholder business practices, but to what degree it is unknown. |
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| Individual |
| Clint Gerkensmeyer |
| Benton Rural Electric Association |
| No |
| Benton REA believes the inclusion of revisiting and possibly changing the definition developed in |

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| Phase 1 is not consistent with the previous scope of Phase 1 which was to address FERC Order No. 743 by the due date of Jan. 25, 2012. |
| Yes |
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| No |
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| Yes |
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| No |
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| No |
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| No |
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| No |
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| No |
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| No |
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| No |
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| Yes |
| 100kV may be used as an overall BES definition, but exclusion based on regional differences also needs to be addressed |
| No |
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| Yes |
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| No |
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| Yes |
| Yes. We believe that demarcation is a technical question, and therefore believe Phase II should approach demarcation as a technical question rather than as merely a clarification. If the SDT puts together a technical record supporting its approach to demarcation, we believe the resulting standard will be more likely to survive regulatory review. |
| No |
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| No |
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| No |
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| Group |
| EMP NERC |
| Louis Slade |
| No |
| Dominion notes that no reliability functions have been checked and recommends that all be checked (included). Dominion also suggests including reference to FPA 215 in the sentence referencing Order |

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| 693. |
| Yes |
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| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| No |
| The SDT should pursue a technical analysis of what equipment is needed to support the BES. It should look at the extention of equipment needed on both the load and supply side and not display an inpartiality to inclusion or exclusion for what is really needed to support the BES. (This may lead to additional equipment then we include today in some cases, and less other cases.) |
| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| No |
| The SDT should pursue a technical analysis of what equipment is needed to support the BES. It should look at the extention of equipment needed on both the load and supply side and not display an inpartiality to inclusion or exclusion for what is really needed to support the BES. (This may lead to additional equipment then we include today in some cases, and less other cases.) |
| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| No |
| The SDT should pursue a technical analysis of what equipment is needed to support the BES. It should look at the extention of equipment needed on both the load and supply side and not display an inpartiality to inclusion or exclusion for what is really needed to support the BES. (This may lead to additional equipment then we include today in some cases, and less other cases.) |
| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| No |
| The SDT should pursue a technical analysis of what equipment is needed to support the BES. It should look at the extention of equipment needed on both the load and supply side and not display an inpartiality to inclusion or exclusion for what is really needed to support the BES. (This may lead to additional equipment then we include today in some cases, and less other cases.) |
| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| Yes |
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| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| Yes |
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| Yes |
| Dominion suggests use of studies performed by Transmission Planners, Reliability Coordinatros and Transmission Operators may be useful. |
| No |
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| Dominion believes that it is important for the SDT to give due consideration to jurisdictional issues such as; state versus federal, retail versus wholesale, etc. as it enters this phase of the project. The SAR mentions three terms (i.e., Elements, electrical components, and equipment) as either necessary or in “support” of the reliable operation of the BES. Dominion believes clarification of these terms is necessary before advancing the SAR. |
| Group |
| Florida Municipal Power Agency |
| Frank Gaffney |
| No |
| The scope should be revised to clarify that if the BES definition is changed as a result of the technical examinations being undertaken, conforming changes should be made to the Statement of Compliance Registry Criteria, including (but not necessarily limited to) Sections I, III and footnote 4. The scope should also be expanded to include clarification of the relationship between the BES definition and the Federal Power Act definition of the “bulk-power system”. FMPA believes that the “bulk-power system” as defined in Section 215 is equal to the Bulk Electric System as defined by NERC plus (protection and) control systems that are covered by the standards. Section 215 defines the bulk-power electric system as: “`(1) The term `bulk-power system' means-- `(A) facilities and control systems necessary for operating an interconnected electric energy transmission network (or any portion thereof); and `(B) electric energy from generation facilities needed to maintain transmission system reliability.” The key phrase is at A: “facilities and control systems”. FMPA believes the best way to move forward is: 1) to interpret "facilities" as used in Section 215 as meaning the same as "Facilities" as used in the NERC Glossary, which would mean that the BES does not include control systems; and 2) to interpret "control systems" as used in Section 215 as those protection and control systems covered by the standards (e.g., CIP, PRC). |
| Yes |
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| No |
| There was a study performed in NPCC concerning what size generator could impact UFLS program design. FMPA believes that study fatally flawed due to flawed assumptions on island size, etc. |
| No |
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| No |
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| No |
| FMPA strongly suggests that the SAR be revised to be more specific. As currently worded - “Determine if there is technical justification for including the equipment which ‘supports’ the reliable operation of the BES”- the SAR is unclear and could lead to circularity, since equipment that is added to the BES by virtue of “supporting” the BES is likely itself “supported” by other equipment, which would then also have to be added to the BES, and so on ad infinitum. “Supported” is also a very ambiguous word, with many gradations from the significant to the insignificant, e.g., does a residential rooftop photovoltaic system “support” BES system frequency? The SDT should therefore set out the types of equipment that it will be examining, e.g. blackstart units. The SAR item should be revised to read: “Determine if there is technical justification for including blackstart units.” If the SDT’s intent is on protection and control systems, then, FMPA believes that protection and control should not be defined as part of the BES, but rather as the “control systems” part of the “bulk-power system” definition. Increased clarity on what control systems are part of the “bulk-power system” beyond the CIP-002 v4 and v5 bright lines and the PRC-005 interpretation within PRC-005-1a would be valuable. |
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| No |
| There is a question as to what type of switch acts as the boundary between BES and non-BES. The NERC Glossary defines Facility as: “A set of electrical equipment that operates as a single Bulk Electric |

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| System Element (e.g., a line, a generator, a shunt compensator, transformer, etc.)" "Operates" is the key word when considering the boundary between Facilities and non-Facilities, and therefore between BES and non-BES. We operate at switches, so, a Facility is essentially defined as the BES equipment between switches. What type of switch is the key question. If only automatic fault interrupting devices (i.e., breakers and circuit switchers) act as that boundary, it would exclude manual and motor operated disconnect switches as able to act as that boundary. The problem with using only automatic fault interrupting devices is that many radial equipment would then not be automatically excluded. For instance, consider a ring bus where a step-down transformer to distribution is connected to one of the ring-bus bus sections (i.e., between two breakers in the ring). The bus section between the two breakers is not radial and is presumably part of the BES. Usually, there is a manual disconnect switch between the bus section and the high-side of the transformer connected serially with the transformer. If that transformer high-side manual disconnect switch is not the boundary between BES and non-BES, that would make the distribution voltage breaker on the secondary side of the transformer the boundary and the entire transformer would become part of the BES. The same would be true for a radial line connected to a ring bus or breaker-and-a-half scheme; the radial line would not be automatically excluded. If it is determined that only automatic interrupting devices can act as the boundary between BES and non-BES, we would see a flood of Exception requests to except the radial transformers and lines. All of those requests will most likely be approved because interrupting one of the paths of a ring bus or breaker-and-a-half scheme is exactly the purpose for which those types of buses are designed, and we would wind up right back to where we are now. Even if that is not the case, the industry would likely change bus designs just to be able to get the automatic radial exclusion. In other words, we'll essentially obsolete ring bus and breaker-and-a-half buses in favor of main and transfer bus schemes, which is inherently a lower reliability bus design, just to be able to get the radial exclusion. FMPA believes that this consideration is not an efficient use of resources and should not be part of the scope, and in fact, if the current criteria are changed, it could have an unintended consequence of reducing the reliability of the BES. |
| Yes |
| There are numerous papers on the comparative reliability of different types of bus designs; e.g., ring, breaker-and-a-half, main and transfer, etc. |
| Yes |
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| No |
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| No |
| FMPA believes that 100 kV is the correct "bright line". To FMPA's knowledge, there has been at least one major event with causes on a system between 100 kV and 200 kV, the 2008 Florida UFLS Event. To FMPA's knowledge, there have been no significant events with causes on a system with a lower voltage than 100 kV other than Acts of Nature that do a lot of damage to distribution systems (e.g., hurricanes, ice storms, etc.). |
| No |
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| Yes |
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| No |
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| No |
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| Yes |
| If FMPA's comments to question 1 are accepted and the SDT determines that the "bulk-power system" of Section 215 is equal to the Bulk Electric System as defined by the BES definition plus "control systems" as the term is used in Section 215, the SAR could include in its scope what "control systems" are included in the "bulk-power system". |
| No |
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| Yes |
| The Statement of Compliance Registry Criteria may need to be changed if changes are made to the BES definition, and entity registration may need to change in accordance with any changes made to the Statement of Compliance Registry Criteria. |
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| Individual |
| Massachusetts Department of Public Utilities |
| Massachusetts Department of Public Utilities |
| No |
| The Massachusetts Department of Public Utilities ("Mass DPU") appreciates the opportunity to provide comments on Phase 2 of the Bulk Electric System ("BES") definition development. Massachusetts is the largest state by population and load in New England. It comprises approximately 46% of both the region's population and electricity consumption. Generating plants located in Massachusetts represent approximately 41% of New England's capacity and our capitol city, Boston, is the largest load center in the region. The Mass DPU supports the effort to develop specific technical justifications for the BES definition. The description of the scope provided above states that the continued development of the BES definition in Phase 2 may include improvements to the definition and, later, contemplates potential revisions to the BES. However, to avoid any misunderstanding, the scope should explicitly state that the Phase 2 work is sufficiently broad such that the language developed in Phase 1 remains open and subject to restructuring and revision based on the technical analysis being undertaken. In other words, the scope should clarify that the analysis in Phase 2 is not being undertaken simply to provide technical justifications for the BES language already approved by the NERC Board of Trustees in conjunction with Phase 1. The Mass DPU continues to believe, as it stated in comments on the 2nd Draft Definition of BES in October, 2011, that reliance on the bright-line threshold absent technical justifications could impose substantial costs on consumers without achieving meaningful reliability benefits. Additionally, we repeat our earlier comment that separating the BES definition into two phases is problematic for both procedural and substantive reasons. This concern is described in greater detail in our earlier comments. |
| Yes |
| In response to this and other questions below regarding whether a technical justification should be pursued to support inclusions/exclusions and the core BES definition itself, the Mass DPU strongly answers in the affirmative. No proposed reliability standard should move forward absent a technical justification demonstrating that the standard is neither underinclusive (leaving reliability issues unaddressed) nor overinclusive (imposing costs disproportionate to the reliability benefit). A technical justification is particularly critical for the core BES definition and its related inclusions and exclusions given the sweeping changes and resulting costs that the final language could impose. For the same reasons, the Mass DPU urges the SDT to develop a sound technical justification to support setting thresholds for including real and reactive power resources in the BES. |
| No |
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| No |
| As stated in our response to question 2, the Mass DPU believes the definition and scope of the BES should be supported by technical justifications. However, we check "no" above because the question itself provides a conclusion about the reliability of a contiguous BES that precedes the data to support it. The words "supports the assumption" and "benefit" bias the issue of whether the BES should be contiguous or not. The statement should simply read: "Do you agree that the SDT should determine if there is a technical justification for a contiguous BES?" The inclusion of facilities under an assumption made without appropriate support that there is a reliability benefit to a contiguous BES creates significant risk of imposing excessive costs on ratepayers. We noted in our comments on the 2nd Draft Definition of BES that the Federal Energy Regulatory Commission's (the "Commission") Order 743 bounded NERC's development of the BES definition by two criteria: (1) the statutory exclusion of facilities used in local distribution, and (2) the requirement that the facilities included be necessary for reliable operation of an interconnected transmission system. Revision to Electric Reliability Organization Definition of Bulk Electric System, Order No. 743A, 134 FERC ¶ 61,210 (Mar. 17, 2011) at PP 8. 20, citing to Revision to Electric Reliability Organization Definition of Bulk Electric System, |

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| Order No. 743, 133 FERC ¶ 61,150 (2010). These limitations help to ensure that costs are not imposed absent attendant meaningful reliability benefits. The imperative to identify such benefits drives the need for technical justifications. |
| No |
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| No |
| As stated in the previous response, Order 743 requires that the facilities included in the BES definition should be necessary for reliable operation of an interconnected transmission system. However, it is not clear how the STD would distinguish a “supporting” from a “necessary” element. The Mass DPU does not believe the BES should include a subcategory of facilities that only “support” reliable operation and do not meet the definition as “necessary.” Expanding the BES reliability requirements to such a subcategory would impose significant and unjustified costs on consumers. |
| No |
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| Yes |
| See general comments in number 2 above. |
| No |
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| Yes |
| See general comments in number 2 above. Additionally, similar to our response to number 3 above, the question’s use of the word “support” should be replaced by a neutral term such as “determine.” |
| No |
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| Yes |
| See general comments in number 2 above. The development of a technical justification for the selection of 100 kV as an “across the board” bright-line voltage level, which the drafting process has so far failed to provide, is essential. We stated in our previous comments that Order 743 provided a 100 kV bright-line threshold as “initial line of demarcation” to be refined through exclusions and exemptions, with flexibility for NERC to propose an alternative proposal. See Order 743A at PP 8, 40. Accordingly, unless and until NERC provides a technical justification for its approach, the standard should use the 100 kV threshold concept in a way that is consistent with the Commission’s guidance. |
| No |
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| Yes |
| See general comments in number 2 above. |
| No |
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| No |
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| Yes |
| This question is unclear. The Mass DPU expects that the STD’s efforts to clarify definitions by seeking technical justifications will necessarily lead to revisions to some of those terms, including the base BES definition itself. For this reason, the Mass DPU repeats its response to question 1 that to avoid any misunderstanding, the scope should explicitly state the Phase 2 work is sufficiently broad such that the language developed in Phase 1 remains open and subject to restructuring and revision based on the technical analysis being undertaken. In other words, the scope should clarify that the analysis in Phase 2 is not being undertaken simply to provide technical justifications for the BES language already approved by the NERC Board of Trustees in conjunction with Phase 1. |
| No |
| This question is unclear. Following clarification of the issue, the Mass DPU may provide comments at a future time on regional variances required in the New England region. |
| No |

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| Again, we are unclear regarding the information this question seeks to elicit. As a general matter, the extent to which modifications of business practices will be needed depends on the BES definition that is ultimately implemented, which requires Commission approval. Additionally, as we state in our response to question 1, we understand the scope of Phase 2 to include consideration of any needed revision or restructuring of the definition following the technical analysis being undertaken. In short, a response to this question (as we understand it) seems premature. |
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| Group |
| Transmission Access Policy Study Group |
| William Gallagher |
| Yes |
| The scope should be revised to clarify that if the BES definition is changed as a result of the technical examinations being undertaken, conforming changes should be made to the Statement of Compliance Registry Criteria, including (but not necessarily limited to) Sections I and III. The scope should also be expanded to include clarification of the relationship between the BES definition and the Federal Power Act definition of the Bulk Power System. The scope refers to the electrical components "necessary for the reliable operation of the interconnected transmission network." To properly track Orders 743 and 743-A, this should be revised to "necessary for operating an interconnected electric transmission network." Finally, the SAR should be revised to take account of NERC's risk-based policies and the benefits to NERC, the Regions, registered entities, and consumers of minimizing the need for exception requests. |
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| TAPS strongly suggests that the SAR be revised to be more specific. As currently worded-"Determine if there is technical justification for including the equipment which 'supports' the reliable operation of the BES"-the SAR is entirely unclear and could lead to circularity, since equipment that is added to the BES by virtue of "supporting" the BES is likely itself "supported" by other equipment, which would then also have to be added to the BES, and so on ad infinitum. The SDT should therefore set out the types of equipment that it will be examining, e.g. protection and control systems. The SAR item should be revised to read: "Determine if there is technical justification for including specified protection and control systems." |
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| Individual |
| Barry Lawson |
| National Rural Electric Cooperative Association (NRECA) |
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| If the thresholds are going to be changed then a technical justification would be needed. The SDT |

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| should examine whether it is appropriate to change the thresholds that were included in the Phase 1 BES definition. |
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| The SDT should determine if there is a need to change how the "continguous" issue was handled in Phase 1 of the BES definition project. If no change is needed, then technical justification is not needed. If the SDT decides to make a change on the "contiguous" issue, then a technical justification would be needed. |
| |
| No |
| NRECA does not agree that equipment "supporting" the reliable operation of the BES should be included in the BES definition. Equipment is either BES or not. |
| |
| The SDT should examine if an automatic interrupting device is necessary for excluding radial lines and local networks in E1 and E3 of the Phase 1 BES definition. Adjustments to the BES definition, if any, should be based on this examination. |
| |
| The SDT should examine if there is a reliability need to making such a revision to the Phase 1 BES definition. However, facilities used in the local distribution of electricity cannot be part of the BES. |
| |
| The SDT should examine if 100kV or a higher voltage level is the approrpriate bright-line for the BES definition. The SDT should not limit its examination to only looking at 100kV as the appropriate bright-line. |
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| Yes |
| Yes, the SDT should examine this issue. |
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| Phase 2 of the BES definition project needs to be the completion of the BES definition project in order to finalize a definition and to allow the industry to work to implement a definition that is not constantly changing. |
| Group |
| NYSEG and RG&E |
| John Allen |
| No |
| The primary focus of the SDT should be to ensure that the BES Definition as approved by both industry stakeholders and the NERC Board of Trustees is clear and understandable, and implemented consistently across the continent. |
| No |
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| No |

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| No |
| At some point, this would need to be addressed: an element which is excluded from BES should be able to separate itself from the BES in the case of a fault on the non-BES element. A non-BES element could also be prone to higher outage rates that a BES element. |
| No |
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| No |
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| No |
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| No |
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| Yes |
| The SDT needs to develop a “BES Definition Application Guide” to ensure that the BES Definition is implemented consistently across the continent: • Exclusion E2 depends on whether contractual or regulatory “services are provided to the generating unit… or to the retail Load.” The SDT should provide specific examples for E2 condition (ii) in which facilities would or would not be excluded. Alternatively, condition (ii) should be stricken. • Both Exclusion E2 and Exclusion E3 are flow-based exclusions, and therefore depend on analysis rather than system configuration. The assumptions and conditions for this analysis are the crux of BES classification. Do these flow specifications apply to all critical system conditions, such as load, dispatch, transfers, and do they apply to both “normal” and “post-contingency” conditions? If so, which contingencies need to be assessed for this analysis – for example, P0 through P7 events in TPL-001-2? • Exclusion E1 is labeled “radial systems” – is this intended to apply to a single transmission line from a substation bus to another substation (with no other connections of 100 kV or higher)? If there were a parallel transmission line from that same bus to that other substation would those lines not be considered “radial”? Are transmission line taps considered “radial systems”? Annotated one-line diagram examples would easily clarify this exclusion. • Does the “Note” in Exclusion E1 that a “normally open switching device… does not affect this exclusion;” mean that the device should be considered not to exist (as if permanently open), or that the device status should be disregarded (do not assume it will be open)? • Inclusion I4 depends on the term “connected at a common point” – this needs to be defined or better explained. For example, is this considered to be the Collector Substation feeder connection low-voltage bus only, or also the high-voltage bus on the high side of the collector transformer at the Collector Substation? If it is the former, it will exclude all of the wind interconnections of all sizes presently in the northeast United States (feeder voltages can be 34.5 kV for wind farms of hundreds of MW capacity). A “BES Definition Application Guide” would be most helpful to industry if it includes both one-line diagrams and explanations with examples for each inclusion and exclusion. |
| No |
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| No |
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| The primary goal of Phase 2 must be to develop guidance for the new BES Definition. Any technical justification efforts should not detract from the guidance effort and must be consistent with the FERC Orders on the BES Definition. There is a risk that technical analyses to justify inclusions and |

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| exclusions of elements in the BES Definition may be generalized to a larger set of conditions, when the analyses apply only to a set of specific situations or system conditions. System behavior depends on many factors, many of which are not standardized for the entire industry. |
| Group |
| Central Maine Power Company and MEPCO |
| Joe Turano |
| No |
| The primary focus of the SDT should be to ensure that the BES Definition as approved by both industry stakeholders and the NERC Board of Trustees is clear and understandable, and implemented consistently across the continent. |
| No |
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| No |
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| No |
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| No |
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| No |
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| No |
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| No |
| At some point, this would need to be addressed: an element which is excluded from BES should be able to separate itself from the BES in the case of a fault on the non-BES element. A non-BES element could also be prone to higher outage rates that a BES element. |
| No |
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| Yes |
| The SDT needs to develop a “BES Definition Application Guide” to ensure that the BES Definition is implemented consistently across the continent: • Exclusion E2 depends on whether contractual or regulatory “services are provided to the generating unit… or to the retail Load.” The SDT should provide specific examples for E2 condition (ii) in which facilities would or would not be excluded. Alternatively, condition (ii) should be stricken. • Both Exclusion E2 and Exclusion E3 are flow-based exclusions, and therefore depend on analysis rather than system configuration. The assumptions and conditions for this analysis are the crux of BES classification. Do these flow specifications apply to all |

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| critical system conditions, such as load, dispatch, transfers, and do they apply to both “normal” and “post-contingency” conditions? If so, which contingencies need to be assessed for this analysis – for example, P0 through P7 events in TPL-001-2? • Exclusion E1 is labeled “radial systems” – is this intended to apply to a single transmission line from a substation bus to another substation (with no other connections of 100 kV or higher)? If there were a parallel transmission line from that same bus to that other substation would those lines not be considered “radial”? Are transmission line taps considered “radial systems”? Annotated one-line diagram examples would easily clarify this exclusion. • Does the “Note” in Exclusion E1 that a “normally open switching device… does not affect this exclusion;” mean that the device should be considered not to exist (as if permanently open), or that the device status should be disregarded (do not assume it will be open)? • Inclusion I4 depends on the term “connected at a common point” – this needs to be defined or better explained. For example, is this considered to be the Collector Substation feeder connection low-voltage bus only, or also the high-voltage bus on the high side of the collector transformer at the Collector Substation? If it is the former, it will exclude all of the wind interconnections of all sizes presently in the northeast United States (feeder voltages can be 34.5 kV for wind farms of hundreds of MW capacity). A “BES Definition Application Guide” would be most helpful to industry if it includes both one-line diagrams and explanations with examples for each inclusion and exclusion. |
| No |
| |
| No |
| |
| The primary goal of Phase 2 must be to develop guidance for the new BES Definition. Any technical justification efforts should not detract from the guidance effort and must be consistent with the FERC Orders on the BES Definition. There is a risk that technical analyses to justify inclusions and exclusions of elements in the BES Definition may be generalized to a larger set of conditions, when the analyses apply only to a set of specific situations or system conditions. System behavior depends on many factors, many of which are not standardized for the entire industry. |
| Individual |
| David Dockery, NERC Reliability Compliance Coordinator |
| Associated Electric Cooperative, Incorporated |
| Yes |
| |
| Yes |
| |
| Yes |
| In several of these areas, the SDT could adopt a simple 0.1%, or one-in-one-thousand, (negotiable) as a part of risk assessment. Assets contributing toward BES reliability below that bright-line, would require less focus that those above that bright-line. |
| Yes |
| The question has been raised by FERC, so we should attempt to answer it. Logically, it makes sense, although one could argue that a primarily islanded sub-system but with moderate export/import capability could be interconnected but not necessarily be contiguous with the BES. |
| No |
| AECI is proposing that Surge Impedance Loading of transmission lines be considered in establishing sub-system BES via an MVA bright-line. That approach could be pertinent to this discussion as well. |
| Yes |
| Taken to extreme, this broad statement could capture all equipment within our Interconnections, including all loads because load is necessary to recovery from black-start yet exact loads are very difficult to pinpoint until blackstart recovery is underway and the exact initial system recovery state is understood. Beyond load-shed targets set by RCs, and communicated to all entities responsible for meeting those targets, UFLS and UVLS at the distribution levels should remain out of scope. That said, perhaps some conceptual boundary should be established, that properly bounds the scope of “supports” to NERC and FERC jurisdiction. |
| Yes |

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| AECI proposes that, if a discrete element’s contribution toward the overall reliability of the BES is less than 0.1%, or one-in-one-thousand, then beyond periodic communication to the asset owner regarding its role within a BES Interconnection’s reliability, that element should remain comfortably out of BES reliability focus. (Although 0.1% is subjective, such analysis is based upon sound risk-assessment principles.) |
| Yes |
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| No |
| |
| Yes |
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| No |
| Again the SDT adopting something like a 0.1%, one-in-a-thousand, bright-line for % contribution to BES reliability, would apply sound risk-based analysis. |
| Yes |
| |
| Yes |
| First, AECI believes the SDT would benefit from considering per-unit Surge Impedance Loading (SIL-pu) alongside the corresponding normal thermal ratings, whichever is less, for typical compensated/uncompensated and Overhead/Underground transmission lines at various kV levels. A single MVA bright-line could then act to screen which sub-system elements fall in or out of the BES definition. Assessing characteristic SIL provides insight into each transmission sub-system’s ability to either help mitigate or isolate effects of a major BES disturbance, and provides a better measure to technically aggregate the transmission sub-systems that truly deserve sharp industry focus. This proposed concept could be first verified using large system dynamic studies and if found valid with few exceptions, provide a simple yet superior metric for BES inclusion/exclusion. Second, AECI maintains that should this SDT fail to appropriately sharpen industry focus, by erroneously indentifying up to 10x the number of assets actually necessary to BPS reliability, then they will have exposed the BES to greater risk due to inattention. See IEEE Transactions on Power Apparatus and Systems, Vol.PAS-98, No.2 March/April 1979 pp606-617, “Analytical Development of Loadability Characteristics for EHV and UHV Transmission Lines”, as well as its referenced articles. See AECI related white-paper prepared for the BES Definition SDT, as well as AECI's referenced Eastern Interconnection PSEE 2011 Winter Peak Branch-data, with per-unit SIL calculations, for further analysis, available from AECI upon request. |
| Yes |
| |
| No |
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| Yes |
| AECI believes that the inclusion of flowgates needs to be technically justified. Many times, the first RC-proposed solution to FG issues within the sub-300kV networks, is to open immediate up-stream or down-stream from that FG. Such FGs can then hardly be considered necessary for the reliable operation of the interconnected transmission network. |
| Yes |
| AECI believes that the Phase I Definition E3-c: “Not part of a Flowgate” needs clarification. NERC Glossary_of_Terms_2012January11’s “Flowgate” term Definition 2, FERC Approved 11/24/2009, indicates the FG is comprised of one or more monitored transmission Facilities and optionally one or more Contingency Facilities, indicating that the monitored facility is typically that FG weaker element(s) while contingency Facilities, if any, tend to be those higher-loaded elements that are Outaged within an OTDF calculation. In Phase I Definition balloting discussions, some SDT members seemed to think the Contingency Facility elements were in scope of E3-c, and not the monitored element. Practically, inclusion of monitored element and not contingency element(s), makes very little sense. However regarding only contingency element(s) and not the monitored element(s) does make sense. |

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| No |
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| BES Definition Phase I E4 needs technical justification. Ownership seems irrelevant to BES Reliability discussion, so “owned and operates by the retail customer solely for its own use”, should possible be replaced by “owned and operated solely in conjunction with specific industrial loads.” |
| Individual |
| Tracy Richardson |
| Springfield Utility Board |
| Yes |
| SUB agress with the scope of Phase 2, and believes it to be necessary to address critical and potentially impactful issues and concerns raised in Phase 1. It was mentioned by WECC General Counsel during the February 1, 2012 WECC Compliance User Group meeting that a “Guidance Document” with sample BES one-line diagrams has been drafted, and that it will be issued once it is approved by NERC. SUB would greatly appreciate such a clarification document that wold provide the illustration of a BES System. |
| Yes |
| This question is materially different in scope than what the BES definition provides for. SUB would encourage the STD to tighten its questions around the specific language of the BES definition rather than include expansive language such as “used in the reliable operation of the BES.” (What does that mean? It is SUB’s belief, based on multiple interactions with regulators and Registered Entities that there is no common agreement on what resources are “used in the reliable operation of the BES”. SUB suggests that this language should have been stricken from the question as it adds to confusion rather than enhances clarity). SUB does not agree that ALL reactive resources should be automatically included in the BES Defintion. For example, is a local network (100 kV or above), which is otherwise excluded, but has a recative device used for power factor correction (100 kV or above), still excluded? There are a significant number of reactive resources that are used to serve systems that provide service primarily to load, with either no or a minimal amount of generation. Exclusion language should have been modified to exclude those reactive resources from the BES that are radial serving only load or local networks that serve load (with less than 75MVa of generation). SUB does not agree with Exclusion E.4. referring to only those “retail customer” reactive power devices. This is too narrow and does not accurately reflect the use of reactive power devices installed by Registered Entities when retail customers do not “fix” their reactive power issues on their own. SUB previously recommended, in the October 2011 BES Definition comment period, that the language in I5 and E4 be consistent, and that “retail customer” should include Registered Entities as well as end users. The language is overly broad and will generate a significant amount of paperwork. SUB suggested the following language: I5 – Static or dynamic devices dedicated to supplying or absorbing Reactive Power that: a) are connected to 100 kV or higher and are not part of a radial system or area network that are excluded from the BES; or b) are connected through a dedicated transformer with a high side voltage of 100 kV or higher and are not part of a radial system or area network that are excluded from the BES, or; c) are connected through a transformer that is designated in Inclusion I1 and are not part of a radial system or area network that are excluded from the BES. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| Yes |
| SUB agrees that the SDT should examine the question of where the line between BES and non-BES Elements would be drawn, creating “contiguous vs. non-contiguous” BES. SUB also agrees that BES Definition should not mandate contiguity for the BES, and that a mandate that the BES must be contiguous could have unintended consequences. SUB appreciates that the SDT recognizes the importance of this concept and agrees to discuss issues of a contiguous system in Phase 2. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| Yes |
| SUB supports the addition of Distribution Facilities as an exclusion from the BES Defintion but beliees |

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| that Phase 2 needs to clearly define the difference between Distribution and Transmission Facilities by identifying (and justyifying) the equipment with “supports the reliable operation of the BES”. It was presented by WECC General Counsel during the February 1, 2012 WECC Compliance User Group meeting that a “Guidance Document” with sample BES one-line diagrams has been drafted, and that it will be issued once it is approved by NERC. SUB would greatly appreciate such a clarification document that wold provide the illustration of a BES System. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| No |
| According to the SDT’s Summary Considerations of the BES Defintion comments, “The ‘single point of connection of 100 kV or higher” is where the radial system will begin if it meets the language of Exclusion E1 including parts a, b, or c and does not necessarily include an automatic interrupting device (AID)’”. SUB supports the SDT including an automatic interrupting device (AID) in Exclusions E1 and E3 and does not see the need for a technical justification for being included in the Exclusions. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| Yes |
| SUB understands Blackstart Resources to not be a part of the BES Definition, but rather as part of Inclusion I3 language. Based on the numerous Registered Entities that have expressed concern with the inclusion of Blackstart Resources, SUB agrees that the SDT should pursue technical justification to support the inclustion of Cranking Paths in the BES definition, as well as for retaining Blackstart Resources as part of the definition. |
| No |
| SUB is not aware of existing technical justifications that would assist in this issue. |
| Yes |
| SUB is open to others’ suggestions for other criteria to be considered for a bright-line voltage level, however, SUB is generally comfortable with a 100 kV bright-line voltage level. Left as is, more Local Networks will be included in the BES Definition than should be for BES reliability purposes, either because the Exclusion E3 does not apply or, as communications from NERC have clearly indicated that exceptions under the Exception Process will be “rare”. As it stands now, 1 kilowatt hour could flow out of a Local Network and that Local Network would not be eligible for exclusion. Flow into the system could be 100,001 kWh in an hour, 5,000 kWh could be generated within the system, 105,000 could be consumed by local retail load, and 1 kWh could flow out. SUB is not aware of a situation where the reliability of the BES could be materially impacted by 1kWh. This is the equivalent of a teardrop down the Niagra. Based on this and the understanding that NERC does not want to chase teardrops, SUB does agree that the SDT should pursue pursue technical justification to support allowing power flow out of the local network and allow the local network meeting those conditions be subject to outright exclusion from the BES. Under the current approved definition, individual resources equal to or below a nameplate rating of 20 MVA or gross plant aggregate nameplate rating greater than 75MVA are excluded from the BES if they are not blackstart resources. Similarly, Local Networks could technically demonstrate exclusion from the BES if they demonstrate that a power flow analysis shows that no more than 75 Megawatts [as an example] would flow out of the Load Network in any individual hour of the Model Period which must be no less than 1 year and no more than 5 years. If this criteria is met and the registered entity’s local network that does not have blackstart resources within the LN, the LN would be excluded from the BES for the duration of the Model Period or until such time as actual measured power flowing out of the Local Network is greater than 75 MW in any hour. One may have to consider some scenarios: 1)Let’s consider the scenario that an entity demonstrated that their power flow model showed that the maximum power flow out of a Local Network (LN) was 60 MW in any hour over the next 36 months. In month 13, the actual flow out of the LN was 80 MW in one hour. This exceeds 75 MW for any hour and the Local Network would no longer be excluded. Rather than automatically push the entity to a potential situation of immediate non-compliance, the entity could apply for an exemption at any time prior to the “80 MW in one hour event” that, if accepted, showed the maximum amount of MW that could flow out of the Local Network and still be in compliance. The entity could have both an outright exclusion [up to 75 MW in any hour] as well as an exception [e.g. up to 100 MW in any hour]. The process for the exception may be different than the modeling requirements for the exclusion. The point being, an entity should still be able to be eligible |

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| to apply for and potentially receive an exemption even though it has an outright exclusion. 2)It seems reasonable to consider the situation where a Registered Entity has interconnected Local Networks (LN). The STD may need to consider requiring that where a Registered Entity has multiple LNs from the same transmission sources that the load flow model look at the power flowing to the transmission sources from the LNs, not just out of an individual LN. The STD may need to consider setting the criteria based on "power out of the Local Network or Local Networks sharing the same transmission sources". This may not be typical, but would include the situation where 115kV systems (as an example) owned by one entity were tapped off a 230 kV system owned by another entity where the taps shared the same transmission sources. SUB supports the exclusion of LNs from the BES comparable to the exclusion of other facilities, and believes there should be a Local Network Exclusion Technical Justification using power flow studies based on industry standards. Without exclusions, determining exemptions will be left to the discretion of Reliabiltiy Coordinators. This could create ambiguity and inconsistency of applications for exclusions and raise questions about the consistency of the requirements. Further, including a Local Network into the definition of the BES that has power flowing out of its system (that is not on a blackstart or otherwise critical path) that is less than the power flowing into the BES from thresholds allowed for other elements is arbitrary. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| Yes |
| SUB recommends that unscheduled power flow should not be considered, but that it is applicable only to scheduled power flow. SUB supports the exclusion of LNs from the BES, and believe there should be a Local Network Exclusion Technical Justification. Without specific parameters, determining inclusions and exclusions will be left to the discretion of Registered Entities (too many). This would create ambiguity and inconsistency of application. |
| No |
| SUB is not aware of existing technical justifications that would assist with this issue. |
| Yes |
| For those Registered Entities with outright exclusions, SUB believes there should be a technical justification for third parties who move for the inclusion of a Registered Entity. |
| Yes |
| SUB appreciates the question, but caution's the STD. Small entities are at a disadvantage with this question because of the "one size fits all" approach to expectations regarding the level of expertise expected of Registered Entities. SUB has done some research and conceptually has thoughts outlined above, but the STD should bear responsibility of providing coherent studies to prove that elements do impact the BES rather than small entities having to struggle to justify why elements (or Local Networks) do not impact the BES. |
| Yes |
| SUB believes the greatest regional variances associated approved NERC Reliability Standards will be in geography, with the west being more spread out, and the east more dense. SUB also thinks that differing voltage levels will demonstrate regional variance. |
| Yes |
| Registration changes based on outright exclusion, and applications for exclusions...will be a business practice change for both NERC and Reliability Organizations (ie., WECC). |
| SUB appreciates the opportunity to provide comment and sees Phase 2 as a necessary follow-up to the development of the BES Definition. |
| Individual |
| Sylvain Clermont |
| Hydro-Quebec TransEnergie |
| No |
| Hydro-Quebec TransEnergie (HQT) believes that several items should be added to the SAR project and addressed with high priority. 1. Define what is meant by "necessary for the reliable operation of the interconnected transmission network". This is particularly important because characteristics differ widely amongst Interconnections. For example, interconnected system reliability issues have to be distinguished from service continuity issues. 2. Determine if there is a technical justification to |

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| support the 300 kV threshold for E3 exemptions on Local Network elements. 3. As HQT has stated before, the SDT should consider more than one definition to allow for several application levels of the Reliability Standards: Standards related to transmission system design (TPL-001 to TPL-004) should be applicable to the highest voltage(s) on the interconnected grid (first level), other reliability standards should be applied to local networks (with supply-demand balance and interchanges) (second level), and lastly, some strandards should apply to excluded parts of the BES such as generators contributing to voltage and frequency regulation. |
| Yes |
| This item should be given top priority. |
| No |
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| No |
| HQT believes that contiguity of the BES should not be necessary. For example, a generator may be part of the BES while the path to that generator doesn't necessarily need to be part of the BES. |
| No |
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| No |
| This must be addressed in the relevant Reliability Standards only. |
| No |
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| No |
| This has been discussed at length in Phase 1. |
| No |
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| No |
| Blackstart requirements exist whether or not corresponding resources are part of the BES. Such resources are covered in appropriate Reliability Standards. The SDT has already discussed the technical concepts in its Phase 1 deliberations. |
| No |
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| Yes |
| A multi-level (tiered)application of standards and multi-level definition could be very helpful in addressing this issue. HQT does not consider that there is necessarily a direct relation between the voltage level and the impact on reliability. |
| No |
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| Yes |
| Explanations should be given about the meaning of the second part of E3 b) (LN does not transfer energy originating outside the LN for delivery through the LN) and the reason it is added to the first part (Power flows only into the LN). Is this about commercial issues? |
| No |
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| Yes |
| The Single point of connection needs clarification. Also, there is a need to clear up the ambiguity between E1 and E3 concerning the contiguity of transmission Elements (including below 100 kV in E1) and contiguity of transmission Elements only above 100 kV (in E3). |
| No |
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| No |

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| HQT is concerned about the difficulties that the SDT will experience working on phase 2, while Phase 1 is not yet approved and may well need new work efforts. Moreover, HQT believes that the final definition should target Facilities that represent the backbone of the electric power grid and move large amounts of power from generation to Load centers and not those that directly serve end-use Load customers . |
| Individual |
| Kathleen Goodman |
| ISO New England Inc. |
| No |
| As written, the scope is too open-ended and unclear. |
| No |
| We believe that the thresholds for Real and Reactive Power Resources are properly defined at this time. The 20 MVA individual and 75 MVA composite thresholds should not be increased to exclude more generation. In some cases generation below this threshold may play a role in maintaining system reliability. The presently prescribed thresholds and the provisions of the NERC Statement of Compliance Registry, allowing NERC/Regions to register any generator, regardless of size, that is material to the reliability of the bulk power system, should remain as the determinant for those Real and Reactive Power Resources to be required to register and comply with all applicable NERC Reliability Standards. However, there has been some confusion on the interpretation of I4. In NERC's petition to FERC for approval of a revised definition of the BES, NERC states, "Inclusion I4 – This inclusion was added to the BES Definition in order to accommodate the effects of variable generation (e.g., wind and solar resources). Although this inclusion arguably could be considered subsumed in Inclusion I2 (because the gross aggregate nameplate rating of the power producing resources must be greater than 75 MVA), it was considered appropriate for clarity to add this separately-stated inclusion in order to expressly cover dispersed power producing resources utilizing a system designed primarily for aggregating capacity." I4, as presently drafted, states: "I4 - Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above." ISO-NE has assisted NPCC in the registration of large wind farms. It was our understanding, and it continues to be, that although wind-farms utilize a "collector system" for aggregating capacity at voltage levels below 100 kV (typically 34.5 kV), the common point in the wording above is understood, and defined, to be the 100 kV, or above, interconnection that is common to all the collector strings after transformation from 34.5 kV to > 100 kV, and not the 34.5 sub-transmission strings common to themselves. This is how the large wind farms in New England have been registered. If the aggregate real power was >75 MVA and the multiple collector strings ultimately were transformed from 34.5 kV in order to serve load at > 100 kV, then the wind-farm generation was registered based on its connection at a common point at a voltage of 100 kV or above. However, it has come to ISO New England's attention that some have interpreted I4 such that if the collector strings are below 100 kV then the wind-farm, although over 75 MVA, would be exempt. Although this interpretation seems out of sorts with the precedent that has been established using the "Registry Criteria" since the inception of the ERO, it presents a problem if the wording does not clearly identify what we believe to be the correct interpretation of the words "common point". Particularly, a clarification of I4 should be made to specify how a wind farm, connected to a common collector bus at something less than 100 kV, but then stepped up to a single point ("common point") greater than 100 kV, may be treated. The requested clarification, within the I4 definition itself, should succinctly define the "meaning" of the "common point" to define that point as the 100 kV interconnection, if such an interconnection exists. |
| No |
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| No |
| There is no need for the BES to be contiguous. |
| No |
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| Yes |

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| Assuming “Support” refers to a something like the benefit provided by reactive resources that are not included under the existing definition, such a justification would be beneficial. However, clarification on what “supporting” means would be required as the equipment included here could be limitless. |
| No |
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| No |
| It is unclear what is meant by this. However, we are concerned that this would lead to changes to the BES definition itself. |
| No |
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| No |
| This is a topic that has already been vetted and additional work on this would be counterproductive. |
| No |
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| No |
| The initial direction regarding 100 kV was clear. |
| No |
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| No |
| It seems that if power can flow in both directions then it is not a local network. This would be in direct contradiction to FERC Order 743 and 743-A. |
| No |
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| Yes |
| Inclusion I4 should be further clarified/justified to support the potential for significant “distributed” resources such as wind-farms to be not included in the BES. |
| Yes |
| The terms “Retail Load, Retail Generation and Retail Meter” should all be better defined to avoid improper or inconsistent interpretations. |
| No |
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| Yes |
| As this effort has the potential to change either the BES definition itself or the interpretation of the definition, this will likely influences many business procedures. |
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| Individual |
| Joe Petaski |
| Manitoba Hydro |
| No |
| Manitoba Hydro disagrees with the development of Phase 2 of this project for the following reasons: A. The determination of whether there is a technical justification for the selection of 100 kV as the bright-line criterion is inappropriate to include within the scope of this SAR, as that determination should have been made in Phase 1. FERC Order No. 743 did not require NERC to use 100 kV as the criterion for the bright-line definition of BES. The order simply cited the Commission’s view on the issue and allowed the criterion to be developed through NERC’s Standards Development Process. NERC has already had the BOT approve a 100 kV threshold, presumably based on a technical justification, otherwise NERC staff should not have recommended the Phase 1 definition for approval by the BOT. B. In general, the development of a technical justification through issuing a SAR (as detailed in several of the Phase 2 issues) is inappropriate. The NERC Standards Development Process requires each SAR to be accompanied by a technical justification. Accordingly, a technical justification for revising the BES definition to address certain issues should already be in place. If there is no |

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| justification yet, information should be solicited through some other mechanism, such as a NERC data request, study, or the development of a White Paper. C. Initiating Phase 2 prior to receiving approval on Phase 1 will result in implementation issues for the BES definition. D. The list of issues to be addressed appears overly ambitious and will detract industry resources from projects that are more critical to system reliability. Manitoba Hydro believes that further modification to the BES definition should only be initiated if and when FERC has approved the Phase 1 definition and items such as the 100 kV threshold are called into question by FERC, or by an industry submitted SAR which includes technical justification. If NERC wants to establish technical justification for further modification to the BES definition, this should be accomplished through other mechanisms such as the development of a White Paper. |
| No |
| See Question #1 comments. |
| No |
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| No |
| See Question #1 comments. In addition, it is not clear what is meant by “contiguous” BES. If this means that all Regions should have the same definition, that already has been decided in Phase 1 through FERC’s direction to have an Exception Procedure in place. It is not clear how the definition of BES would be revised to recognize such a benefit, other than eliminating exceptions. |
| No |
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| No |
| See Question #1 comments. In addition, it is contradictory to “include” within a definition of BES equipment that is clearly excluded by the BES definition. If equipment is said to “support” the reliable operation of the BES it is not part of the BES. |
| No |
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| No |
| See Question #1. In addition, Manitoba Hydro believes that Protection Systems should be a pre-requisite to meet E3 and this item should be pursued once FERC has ruled on Phase 1 of the BES definition. |
| No |
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| No |
| See Question #1 comments. |
| No |
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| No |
| See Question #1 comments. |
| No |
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| No |
| See Question #1 comments. In addition, Manitoba Hydro believes that in the interest of reliability, power should not be permitted to flow out of the local network under normal operating conditions. |
| No |
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| No |
| See Question #1 comments. |
| No |
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| No |

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| No |
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| -Manitoba Hydro does not support Phase 2 of Project 2010-17 but there are a number of outstanding issues with the BES definition that should be addressed once FERC has ruled on the BES definition submitted in Phase 1: A. Industry approved minimum thresholds to support BES exceptions should be developed to improve the consistency when ruling on BES exceptions. B. A Protection System should be required to meet E3 to ensure that local networks do not adversely impact the BES. C. The sentence 'This does not include facilities used in the local distribution of electric energy' included in the core definition is repetitive as it is already covered under the listed exclusions. D. Only the Blackstart Resources identified through NERC Reliability Standards requiring Blackstart plans should be included in the BES definition since 'Transmission Operator restoration plan' is not a NERC defined term. |
| Group |
| ACES Power Marketing Standards Collaborators |
| Jason Marshall |
| No |
| We agree with much of the scope but offer the following comment where we disagree with a specific issue in addition to our concerns stated in the following questions. The following sentence should be struck from the Purpose or Goal section because it is a judgment of the previous outcome and does not represent the current purpose of the SAR and contradicts the "Identify the Objectives" section. "The definition encompasses all Elements necessary for the reliability operation of the interconnected transmission network." |
| Yes |
| We agree that the SDT should pursue a technical justification to set thresholds for Real and Reactive Power Resources. The current thresholds for generators in I2 are arbitrary. It does not make sense to use one threshold for a single unit and a different threshold for a plant. We believe if 75 MVA can be reliabily used for plant, then it can also be reliably used for a single generator. |
| Yes |
| The Resources Subcommittee should be consulted for determining appropriate existing technical studies. Additionally, Project 2007-18 Reliability-based Control may have some studies and their field test results might be useful. At one point, there were minimum MW limits for the generator data that RCs, BAs, and TOPs submitted through the System Data Exchange (SDX). The SDX Self-Directed Working Team should be consulted to find out if those limits still exist and their justification. |
| No |
| We do not agree with the need to pursue a technical justification that supports the assumption that there is a reliability benefit to a contiguous BES. It is premature to assume that it is a reliability benefit. Rather, we do support the need to examine the issue without a bias toward a pre-determined outcome. |
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| No |
| This is a vague goal that needs to be better defined before we can support it. What does support the BES mean? Is this intended to draw in distribution and sub-transmission? If so, this should not be pursued. |
| |
| We disagree with pursuing this technical justification. There is no apparent basis for it. There will always be an automatic interrupting device upstream if it is not directly on the radial connection. Adding a requirement to have an automatic interrupting device for radial systems (E1) and local networks (E3) will unnecessarily include distribution systems in the BES. The requirement also likely will not be consistent with Appendix 5B - Statement of Compliance Registry Criteria which limits registration of Distribution Providers to those with loads greater than 25 MW. Radial systems and local networks are in essence distribution systems and those without automatic interrupting devices at the point of interconnection are often small systems that may not meet the 25 MW threshold in Appendix 5B – Statement of Compliance Registry. |

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| No |
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| No |
| We do not agree with including Blackstart Resources and Cranking Paths in the BES definition. First, some Blackstart Resources and Cranking Paths are on the distribution system. No distribution facilities should be included in the BES. Second, this provides a disincentive for generators to provide Blackstart Service. There is no requirement for a generator to offer this service and some may simply decide it is easier and reduces compliance risk to not provide the service. Third, ERCOT has a blackstart market and the generators do not know they will be a Blackstart Resource for the next two years until about one month before the service starts. A generator that otherwise is not part of the BES then becomes part of the BES, and the generator has approximately a month to comply with newly applicable reliability standards. Fourth, the conditions under which Blackstart and Cranking Paths will be used makes their inclusion unnecessary. Blackstart and Cranking Paths will be used during a complete blackout. The generators will be operated manually and communications will likely be by radio. The substations in the Cranking Paths will likely be on station batteries and may also be operated manually or via radio communications. It is not likely when Blackstart Resources and Cranking Paths are needed that their use could be compromised by outside influences. Thus, the only real need to include Blackstart Resources and Cranking Paths in any NERC standards is to essentially require that there are some included in the Transmisison Operator’s restoration plan. EOP-005 already does this. At the very least, an inclusion criteria should not be established to include Blackstart Resources below the 25/75 MVA thresholds and Cranking Paths below 100 kV. There is no apparent justification for this. |
| Yes |
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| Yes |
| We can think of no reason to go below 100 kV as a bright line. |
| No |
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| Yes |
| We support pursuing this technical justification. Since this would make the local network appear as resource, the power flow out of a local network should be allowed to be at least the minimum generation thresholds for aggregate generation as identified in I2. This currently would be 75 MVA. |
| Yes |
| The same technical studies for supporting Real and Reactive Power thresholds could be used to justify this level. |
| Yes |
| The drafting team needs to further justify using Flowgates and major transfer paths in WECC to prevent use of E3 (Local Networks). First, preventing the use of EC for major transfer paths is redundant with the criteria for E3. A transfer path cannot meet the criteria for E3 if it transfers power across the interconnection. It is stated directly in the criteria. A major transfer path in WECC by definition will transfer power. Second, using Flowgates to prevent the use of this criteria is problematic because of the ease with which a Flowgate can be created and submitted to the IDC. Flowgates are updated monthly in the IDC which means the BES could change monthly based on the applicability of E3(c). Third, permanent Flowgate is not defined and it is not clear what is meant by it since Flowgates are updated monthly in the IDC. If the drafting team continues to use Flowgates, they should at a minimum consult with the IDCWG to develop a better description than permanent. Fourth, based on response to comments from phase I, it appears the SDT wants to use Flowgates to prohibit use of E3 because “these facilities are more likely to be used in the transfer of bulk power than not”. This is redundant with the criteria which already states that the local network does not “transfer bulk power across the interconnected system”. |
| Yes |
| The drafting team should evaluate whether gross or net ratings for generators should be used in the definition. It seems that any threshold that is identified from a technical study to identify minimum generation thresholds would apply to the net injection of power and, thus, net rating. The “Note” |

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| statement in E1 should be further clarified to state that normally open switches do not prevent use of this exclusion. As stated now, it indicates normally open switches do not impact the exclusion which is confusing since impact can be positive or negative. |
| No |
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| No |
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| We agree with the need to clarify the relationship between the Bulk Electric System and the Statement of Compliance Registry. If these are not aligned it will be possible for an entity to be registered but not part of the Bulk Electric System. For instance, a Transmission Owner that owns a single radial 138 kV line would qualify for exclusion under E1 but would still be registered. Since the standards are written for the BES, no standard would be effective against this TO. We answered no to question 3. This means the NERC commenting software did not give us an opportunity to comment on question 3a. Here is our comment for question 3a. One approach to evaluate the impact of a non-contiguous BES would be to assess the impact of the non-BES area on the BES. Since the purpose of reliability standards is to prevent instability, uncontrolled, or cascading, such an event should be evaluated in the the non-BES area to determine if it impacts the BES areas. If it does not, then it should not be included. |
| Individual |
| Andrew Z Pusztai |
| American Transmission company, LLC |
| Yes |
| However, it may be necessary to propose revisions and clarification to definitions in the NERC glossary of terms. We recommended that the scope of work include reference to these potential revisions. |
| Yes |
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| No |
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| No |
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| No |
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| No |
| Addition of the concept of “support” does not establish a bright line definition for BES. |
| No |
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| Yes |
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| No |
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| No |
| Including cranking paths could add system elements not otherwise included in the base definition or other inclusions and could add unnecessary complication to the definition. |
| No |
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| No |
| The inclusion and exclusion qualifications in the currently proposed BES definition are adequate without any further technical justification. |
| No |
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| Yes |
| The criterion should reflect the normal operation of the local network and not require the network to be included in the BES because of infrequent, abnormal situations. |
| No |
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| No |
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| Yes |
| ATC recommends the SDT add a statement to indicate that an element that does not meet the base BES definition or any of the inclusion criteria is not a part of the BES. This is suggested to avoid an interpretation that elements that are not exluded by any of the exclusion criteria are by definition included. One methodology should be stated in figuring out what is part of the BES. An entity needs to start with the root BES definition, then review the Inclusions and Exclusions, not the other way around which may have a different outcome. |
| No |
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| No |
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| Group |
| ISO/RTO Council Standards Review Committee |
| Al DiCaprio |
| Yes |
| We generally agree with the proposed scope. However, some of the proposed details appear to be wandering into the areas where they are not needed to address stakeholders' comments from previous posting, and as such may render the scope to be extremely wide; that could result in several iterative steps before being finalized and approved by the industry. For example, "the definition development may include other improvements to the definition as deemed appropriate by the drafting team". This could mean that the project doesn't really have a defined scope. We urge the SDT to focus on what's needed to address stakeholders' comments and meet the FERC directives. |
| Yes |
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| No |
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| Yes |
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| No |
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| We are unable to comment express an agreement or otherwise since we are unclear on what is meant by "support". For example, do any of the followings regarded as "support" equipment: • Protection relays/systems • AVRs • Excitation systems and power system stabilizers • DC supplies; station auxillary supplies • Phase Angle Regulators • SVCs, reactive devices • Etc. These equipements are generally not regarded as BES facilities but they nevertheless provide assistance to enhance operating flexibility and/or achieve enhanced reliability objectives. These equipments are options to compliment basic functions of the BES facilities and as such, can be installed or taken out of service coupled with alternative operating approaches without adversely affect reliability. Having a view to assess if any of them should be included in the BES definition appears to be applying a preconceived notin that some of them will be included not for maintaining reliability, but for their added value to reliability. We have some reservation with the concept. We also wish to raise a potential concern that by developing the various technical justifications, the filtering process can become way too complicated. It could create a bureaucracy, similar to the CIP's Technical Feasibility Exceptions, to manage the "what's in" and "what's out" exercise that will drain time and effort for close to zero value. Once again, we urge the SDT to limit the project scope to only what's needed to address stakeholders' comments and meet the |

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| FERC's directives. |
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| No |
| We are unclear on the applicability of this question, in particular the reference to "an automatic interrupting device in Exclusions E1 and E3" since neither contains such devices. |
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| No |
| Specific treatment and requirements for facilities on the cranking path, including Blackstart Resources, are addressed (or can be addressed) in the EOP-005 standard. The cranking path and Blackstart Resources are subject to change depending on the RC's and TOPs assessment of the practical and effective means to restore their systems. Including them in the BES definition will result in moving targets, and in unnecessary investments (which will be stranded if there is a change to the cranking path and/or Blackstart Resources) and/or discouraging willing facilities to offer such capability. |
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| Yes |
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| Yes |
| We agree that technical justification to support allowing power flow out of the local network under certain conditions should be pursued to support the inclusion or exclusion of certain facilities having power flows into/from the integrated BES based on reliability impact. We do not have a notion on the maximum allowable flow, but trust that the SDT will seek technical inputs from the appropriate parties such as the NERC's Planning Committee and Operating Committee, and other experts in the industry. |
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| Individual |
| Eric Salsbury |
| Consumers Energy |
| No |
| The scope should clearly tie the "reliable operation of the interconnected network" to specific appropriate metrics. |
| Yes |
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| No |
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| Yes |
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| Yes |
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| Yes |

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| By supporting the development of technical justification, Consumers Energy is not advocating a particular result of the technical justifications to be developed. This project should make it clear that any gaps within the existing standards due to registered entities that are not registered as TO/TOP should be addressed by modifying the applicability of the respective standards, rather than via involuntary registration. |
| Individual |
| Michelle D'Antuono |
| Ingleside Cogeneration LP |
| No |
| The scope of the SAR is inappropriate because it generally limits analysis to “technical justifications” without considering other important factors, such as NERC’s statutory authority. Section 215 of the Federal Power Act (“FPA”) does not grant NERC unfettered authority to regulate any facility or control system. Rather, it limits NERC’s authority to the “bulk-power system,” which only includes such facilities that are “necessary for operating an interconnected electric transmission network,” and power from generation facilities “needed to maintain transmission system reliability.” (FPA §215) By the plain language of Section 215 of the FPA, jurisdiction over the “bulk-power system” cannot include any “facilities used in the local distribution of electric energy.” Therefore, it is imperative that the SDT work within the statutory limitations of Section 215 of the FPA to prevent wasting government and industry resources in developing a “technical justification” that cannot withstand basic legal review. That is, NERC must first establish the “statutory/legal justification” to support a revision to the BES definition before spending time and resources on developing the “technical justification.” Moreover, the scope of the SAR is too broad and covers areas, such as Question 5, that were fully vetted in Phase 1 or covers areas that are ambiguous such as Question 3 and Question 4, both of which need further definition in order to limit the scope of what is considered. These problems are due, in large part as discussed below, to the fact that the “language in the SAR is such that any and all aspects of the Phase 1 definition are open to discussion and possible revision.” Such a moving target renders the scope of the SAR and the development of “technical justifications” unworkable. The SDT should consider limiting the scope to a manageable level and focusing on issues that lend themselves better to “technical justification.” Finally, the scope of “Phase II” is contrary to Orders 743 and 743-A, in which the “Commission directed NERC to address the inconsistency, lack of oversight and exclusion of facilities that are required for the reliable operation of the interconnected transmission network, outlined by the Commission in Order No. 743 using the technical expertise available to NERC.” (Order No. 743-A at P 35 (affirming Order 743)). The SAR explains that “due to time constraints” NERC filed |

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| a proposed definition of the BES with FERC by FERC's deadline, but that issues identified in Phase I were deferred to Phase 2. As noted above, the SAR also states that "any and all aspects of the Phase 1 definition are open to discussion and possible revision." The scope of the SAR, therefore, could completely rewrite the BES definition that NERC submitted to FERC. Such a result is contrary to Orders 743 and 743-A and commonsense. Phase 2 should not be used to revisit issues that were resolved in Phase 1 and incorporated in the BES definition filed with FERC. |
| Yes |
| In Phase 1, there was a significant majority of the SDT that felt the threshold level(s) for inclusion in the BES of real power resources needed to be raised and was in the process of justifying this. However, a compromise was reached to defer this to Phase 2 since it was not material to the BES definition developed in Phase 1 (based on FERC directives). The SDT needs to specify a standard of reliability in order to determine the appropriate resource threshold levels for inclusion in the BES. An Adequate Level of Reliability standard, although still in the process of being defined, needs to be used in any technical analysis of Resource threshold levels. Otherwise, any such determination will be subjective and therefore will not be "just, reasonable, not unduly discriminatory or preferential" contrary to FPA § 215. At the very least, the technical analysis should clearly state the basis used to measure reliability versus these threshold levels so that stakeholders can determine the validity of the analysis. |
| Yes |
| The SDT should discuss this issue with the sub-group of Project 2007-9 that developed generation modeling thresholds for proposed standard MOD-026. These thresholds (for modeling) were significantly higher than those in the Phase 1 BES Definition. |
| No |
| Time and resources would be better spent on other issues. This is a very subjective issue for which "justifications" could be produced to give answers either way, depending on the regional and local transmission configurations. Moreover, the analysis would be irrelevant without also considering NERC's jurisdiction over such facilities, as discussed in response to Question 1. For those instances where a contiguous configuration is required to maintain an Adequate Level of Reliability of the BES, and is otherwise justified under law, the Regional Entities should pursue this through the BES RoP Appendix 5C process. |
| No |
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| No |
| The SDT needs to define this question further. This seems to be a purely subjective goal, which could lend itself to a variety of "technical justifications" and include any number of things, such as fuel supply or steam production facilities, which are not subject to NERC Standards or jurisdiction under Section 215 of the FPA. Important systems, such as load shedding systems, are already covered under individual standards. If there are other systems/Elements that the SDT determines are required for an "Adequate Level of Reliability" of the BES, these can be addressed in specific standards, or be included by Regional Entities through the BES ROP Appendix 5C process. |
| No |
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| No |
| This issue was discussed extensively in Phase I. The overwhelming majority of the BES SDT rejected this idea (several times) because the transmission system protection has been designed to accommodate these radial type systems already and maintain an Adequate Level of Reliability for the BES, and because including an automatic interrupting device in Exclusions E1 and E3 contradicts the plain language of Section 215 of the FPA, which denies FERC jurisdiction over facilities used in the local distribution of electric energy (16 U.S.C. § 824o(a)(1) (stating the Bulk Power System "does not include facilities used in the local distribution of electric energy")). As explained in Phase 1, this proposal ignores years of precedent regarding what constitutes "facilities used in local distribution" and defines the BES in such a way as to possibly cover local distribution facilities as well as transmission facilities. For example, it would impermissibly include within the definition of the BES a retail customer's self-provided "hard-tapped" radial line that is located behind the retail delivery point. Radial lines that are used in local distribution of electric energy are outside of FERC's jurisdiction. |

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| Congress did not place any qualifications on the exclusion of facilities used in the distribution of electric energy, and certainly did not make the exclusion contingent on whether the facility has “an automatic interrupting device.” In addition, for those limited situations where exceptions need to be addressed for facilities where sufficient evidence and legal justification for inclusion in the definition of the BES can be presented, the BES RoP team has provided a good mechanism to include those facilities that does not turn on the absence or presence of an automatic interrupting device. The time and resources of the BES SDT would be better spent pursuing other issues. This objective should be stricken from the SAR. |
| No |
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| No |
| Inclusion of Cranking Paths may cause significant conflict concerning the delineation of transmission versus distribution systems because some Cranking Paths could involve distribution facilities. Section 215 of the FPA and precedent is clear that the BES definition cannot include “facilities used in the local distribution of electric energy.” FERC, as well as federal courts, have repeatedly stated that whether a facility is used in local distribution must be determined on a “case-specific” basis (see, e.g., Order No. 888 at 31,980-81). Even if parsing through the division of distribution and transmission facilities on a “case-specific” basis was something the SDT could do, which it cannot, it would certainly detract from the SDT’s focus on other issues. Here again, the SDT would need to specify what standard of reliability is necessary to measure against why Cranking Paths would need to be included. |
| No |
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| No |
| This issue was properly vetted in Phase 1 of the BES Definition project and time would be better spent addressing the issues that provoked the major discussions from Phase I. It would be contrary to the SDT process and FERC’s order to revisit this aspect of the BES definition, which has already been filed with FERC. For those situations where exceptions need to be addressed for facilities above or below this brightline, the BES RoP team has provided the RoP Appendix 5C process |
| No |
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| Yes |
| The scope of this objective needs to be limited to conditions where outward flows would not negatively impact the Adequate Level of Reliability of the BES. |
| Yes |
| There are most likely load flow studies for the regions that demonstrate some of the flows in/out of these systems under at least base case conditions. |
| No |
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| No |
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| No |
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| No |
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| For any of the Phase 2 issues that involve a “technical justification,” it is recommended that the SDT specify a clear basis for measuring the level of reliability desired as a basis for the technical analysis. Otherwise, there could be many outcomes depending on who is doing the analysis resulting in inconsistencies, which FERC has ordered NERC to eradicate. Since NERC has not yet defined the term “Adequate Level of Reliability, “ the SDT will have to make its own determination of a standard to measure these technical justifications against. At the very least, the justifications need to include a clear statement of the reliability related assumptions that form the basis of the “technical justification” so that stakeholders can comment on the assumptions as well as the results. Finally, to ensure that any amendment to the definition of the BES is lawful, the SDT must abandon any attempt |

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| to implement bright-line tests to purportedly distinguish between those facilities that are “transmission” and those that are “local distribution.” FERC, as well as federal courts, have repeatedly stated that whether a facility is used in local distribution must be determined on a “case-specific” basis (see, e.g., Order No. 888 at 31,980-81). As a threshold matter, before devoting any additional time and resources to revising the definition of the BES, there must be a clear understanding of the factors to consider when determining whether a facility is either a local distribution facility or a transmission facility. Currently, such a determination is made by considering a “seven-factor test” that FERC has adopted, and the U.S. Supreme Court has upheld. The “seven-factor test,” of which no one factor is determinative, evaluates the following indicators: (1) Local distribution facilities are normally in close proximity to retail customers. (2) Local distribution facilities are primarily radial in character. (3) Power flows into local distribution systems; it rarely, if ever, flows out. (4) When power enters a local distribution system, it is not reconsigned or transported on to some other market. (5) Power entering a local distribution system is consumed in a comparatively restricted geographical area. (6) Meters are based at the transmission/local distribution interface to measure flows into the local distribution system. (7) Local distribution systems will be of reduced voltage (Order No. 888 at 31,981). The seven-factor test, which recognizes that a bright-line between transmission and distribution is a not a workable approach, is designed to ensure FERC does not impermissibly usurp state and local regulation of local distribution facilities. Thus, the seven-factor test must be part of any process to amend the definition of the BES. |
| Individual |
| Joe Tarantino |
| Sacramento Municipal Utility District |
| No |
| The scope ‘Provide improved clarity on the following: The language for Inclusion I4 on dispersed power resources’ needs to be strengthened. The intent of Inclusion 4 ‘Dispersed power producing resources with aggregate capacity greater than 75 MVA (gross aggregate nameplate rating) utilizing a system designed primarily for aggregating capacity, connected at a common point at a voltage of 100 kV or above’ is not evident, so we don’t know if there is justification for the inclusion. We don’t know if it is supposed to capture 1) Only the components above 100 kV, 2) All components that aggregate 75 MVA, or 3) All components that combine to aggregate the 75 MVA. If Inclusion 4 includes only the components above 100 kV there is not much impact. If Inclusion 4 includes all components that aggregate more than 75 MVA it would include the low side of the collector transformer and some associated low side buss, which may be 21 kV or lower at some windfarms. If Inclusion 4 includes all components that combine to aggregate the 75 MVA it has potential to include over 80 generators per windfarm, none typically over 3 MVA, with the majority of these generators less than 1 MVA. Including these generators would entail significant additional maintenance & documentation and have negligible effect on BES reliability. |
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| Yes |
| Limitations for Power flow out of the LN be restricted to normal conditions and allowed on short-term period for planned outage conditions; Determine an acceptable net power flow out of the LN, not to exceed “X”% of connected local network load not more than “Y” minutes per year. |
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| Yes |
| Depending on the implementation of I4, maintenance organizations that have previously not had equipment designated as BES could have a significant amount of equipment impacted by this determination. This inclusion as part of the BES corresponds with significant increase in their maintenance documentation of requirements without significant increase to reliability. |
| The primary goal of Phase 2 must be to develop guidance for the new BES Definition. Any technical justification efforts should not detract from the guidance effort and must be consistent with the FERC Orders on the BES Definition. There is a risk that technical analyses to justify inclusions and exclusions of elements in the BES Definition may be generalized to a larger set of conditions, when the analyses apply only to a set of specific situations or system conditions. System behavior depends on many factors, many of which are not standardized for the entire industry. An item that should be added to the SAR project and addressed is the necessity to define what is meant by the phrase "necessary for the reliable operation of the interconnected transmission network". Some discussion to establish a reliability matrix must precede other discussions concerning items included in the SAR. If the vast majority of Elements are indeed useful to reliability, not all should be considered as necessary. Stability, reliability and grid integrity issues have to be distinguished from service continuity issues. Elements that contribute to the reliability of the BES have to be distinguished from those that contribute to the reliability of local load (service continuity). Refering to NERC's Reliability Principles, Reliability Objectives (draft), or to the Concept of Adequate Level of Reliability are resources that would be helpful. |
| Group |
| Texas Industrial Energy Consumers |
| Katherine Coleman |
| No |
| TIEC believes that the scope of any examination into the technical justifications for the various thresholds related to the BES definition should be limited to the threshold for Real and Reactive Power Resources, which is raised in Question 2. TIEC's understanding is that most of the comments questioning the technical justification for a threshold in Phase 1 comments related to the threshold for generation resources. TIEC does not believe this concern should result in a wholesale re-examination of the other thresholds for inclusion or exclusion in the BES that were already addressed in Phase 1 and do not appear to be controversial among the commenters. |
| Yes |
| Yes. TIEC believes that examining the technical justification for the existing thresholds for Real and Reactive Power Resources is appropriate, and that these standards are likely overly inclusive. Many commenters requested to have this issue revisited during Phase 1, and this issue should be the focus of any examination into technical justifications in Phase 2. Other thresholds that were not controversial in Phase 1 should not be reopened for discussion. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| See response to Questions 1 and 2. |
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| Group |
| NESCOE |
| Heather Hunt |
| No |
| Comments: NESCOE supports the effort to develop specific technical justifications for the BES definition. The description of the scope provided above states that the continued development of the BES definition in Phase 2 may include improvements to the definition and, later, contemplates potential revisions to the BES. However, to avoid any misunderstanding, the scope should explicitly state that the Phase 2 work is sufficiently broad such that the language developed in Phase 1 remains open and subject to restructuring and revision based on the technical analysis being undertaken. In other words, the scope should clarify that the analysis in Phase 2 is not being undertaken simply to provide technical justifications for the BES language already approved by the NERC Board of Trustees in conjunction with Phase 1. NESCOE continues to believe, as it stated in previous comments, that reliance on the bright-line threshold may impose substantial costs on New England ratepayers without achieving meaningful reliability benefits. Additionally, NESCOE repeats its comment on the 2nd Draft Definition of the BES that separating the BES definition into two phases is problematic for both procedural and substantive reasons. NESCOE's concerns with this approach are described in more detail in those earlier comments. |
| Yes |
| Comments: In response to this and other questions below regarding whether a technical justification should be pursued to support inclusions/exclusions and the core BES definition itself, NESCOE strongly answers in the affirmative. No proposed reliability standard should move forward absent a technical justification demonstrating that the standard is neither underinclusive (leaving reliability issues unaddressed) nor overinclusive (imposing costs disproportionate to the reliability benefit). A technical justification is particularly critical for the core BES definition and its related inclusions and exclusions given the sweeping changes and resulting costs that the final language could impose. For the same reasons, NESCOE urges the SDT to develop a sound technical justification to support setting thresholds for including real and reactive power resources in the BES. |
| Yes |
| Comments: Loss of real power resources in Northeastern North America is covered by regional requirements through the NPCC as well as requirements implemented in New England by ISO-NE planning and operating rules and in New York by NYISO's planning and operating rules. ISO-NE and NYISO planning and operating studies demonstrate that losses of 1200 MW and higher, depending on operating conditions, are generally tolerable with no adverse reliability impact on the bulk electric system in the region. Assuming that the aggregate of generation connected to a local contiguous network is less than 300 MW, then loss of the entire local network and the connected generation will result in a real power loss to the bulk system far below 1200 MW. Therefore, NESCOE suggests there is evidence in these planning and operating studies that the 75 MVA provided in the core definition is overly restrictive with regard to loss of real power. NESCOE believes that an appropriate standard for either radial connections or connections to a local network should be based on technical criteria relating to impact of "loss of source" on the regional bulk network, recognizing local area considerations. NESCOE is not aware of any technical justification for including reactive power resources on local networks in the BES as long as the local network can be separated from the BES by protection and control devices with appropriate local redundancy and speed of operation; in the Northeast, these are already required per NPCC Directory 4. |
| No |
| Comments: As stated in our response to question 2, NESCOE believes the definition and scope of the BES should be supported by technical justifications. However, we check "no" above because the phraseology of this question is problematic. The words "supports the assumption" and "benefit" bias the issue of whether the BES should be contiguous or not. The statement should simply read: "Do you |

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| agree that the SDT should determine if there is a technical justification for a contiguous BES?" The inclusion of facilities under an assumption that there is a reliability benefit to a contiguous BES creates significant risk of imposing excessive costs on ratepayers. As NESCOE stated in its comments on the 1st BES draft, NESCOE believes the BES definition should include only those facilities having a direct impact on the reliability of the interconnected network, to ensure that costs imposed have attendant reliability benefits. The imperative to identify such benefits drives the need for technical justifications. |
| No |
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| No |
| Comments: NESCOE believes the definition of the BES should cover the elements "necessary to the reliable operation of the interconnected transmission network." It is not clear how the STD would distinguish a "supporting" from a "necessary" element; NESCOE does not believe the BES should include a subcategory of facilities that only "support" reliable operation and do not meet the definition as "necessary." Expanding the BES reliability requirements to such a subcategory would impose significant and unjustified costs on consumers. |
| No |
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| Yes |
| Comments: See general comments in number 2 above. Additionally, NESCOE believes that incorporating appropriate automatic interrupting devices in the BES network and at the interfaces between the BES and non BES networks is appropriate. |
| Yes |
| Comments: NPCC system protection design criteria embodied in NPCC Directory 4. |
| Yes |
| Comments: See general comments in number 2 above. Additionally, NESCOE reiterates its comments on the 1st Draft Definition of the BES that it is not appropriate to include black start units in the BES. These units and associated cranking paths are used only for restoration and not system operation. Further, black start units are already covered by existing reliability standards. However, to the extent there is a technical justification for including blackstart resources in the BES, NESCOE believes that a technical analysis based on probabilistic analysis is required to determine if cranking paths should be included in the BES definition. (Again, the word "support" should be replaced by a neutral term such as "determine".) Loss of a cranking path during the relatively brief time that the black start unit is in operation has a much lower probability of occurrence than the failure of the black start resource itself. For example, a transmission path connected to a black start unit may have an availability exceeding 0.999 while a black start unit may have an availability of 0.900 or less. The technical analysis being undertaken should consider availability of the transmission path, availability of the unit, the number of parallel blackstart units capable of supporting a network reenergization as well as the probability, extent, and duration of a blackout. |
| No |
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| Yes |
| Comments: See general comments in number 2 above. The development of a technical justification for the selection of 100 kV as an "across the board" bright-line voltage level, which the drafting process has so far failed to provide, is essential. The BES is a complex system which can be adversely impacted by disturbance situations and/or contingencies at a variety of voltage levels. The response of an electrical network depends on factors including the location of resources and the location of faults as well as the impedance of a given network path. It can be shown that behavior of the network is not simply a function of voltage level. For example in some areas, delayed cleared faults at 230 kV may have no adverse impact on the BES while in other areas such faults at 115 kV may have adverse impact. Accordingly, absent a technical justification for a bright-line voltage level, NESCOE supports the performance-based classification of BES elements as described in NPCC Document A10. |
| Yes |
| Comments: NPCC Directory 1 provides criteria for the design and operation of the bulk power system. |

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| As stated in this document “The objective of these criteria is to provide a “design-based approach” to ensure the bulk power system is designed and operated to a level of reliability such that the loss of a major portion of the system, or unintentional separation of a major portion of the system, will not result from any design contingencies referenced in Sections 5.4.1 and 5.4.2. In NPCC the technique for assuring the reliability of the bulk power system is to require that it be designed and operated to withstand representative contingencies as specified in this Directory. Analyses of simulations of these contingencies include assessment of the potential for widespread cascading outages due to overloads, instability or voltage collapse. Loss of small portions of a system (such as radial portions) may be tolerated provided these do not jeopardize the reliability of the remaining bulk power system (emphases added).” |
| Yes |
| Comments: See general comments in number 2 above. In its comments on the 2nd Draft BES Definition SAR, NESCOE commented that “NERC’s draft technical network exclusions document should be amended such that local networks would be permitted to qualify for network exclusions under E3 if power flowing out of the network is minimal and would not likely adversely impact the BES. For example, transfers of less than or equal to 100 MVA should not have any adverse impact on the BES. The draft technical network exclusions document should be amended to state that transfers of 100 MVA from the local network into the BES are acceptable.” NESCOE suggested 100 MVA as a starting point. NESCOE encourages the SDT to explore this matter further and provide a technically based justification for limiting flows into the BPS from the local network. With due consideration to the threshold of real power discussed in NESCOE’s response to Question 2, NESCOE believes that outflows from the local network within some threshold level should not be restricted at any time. |
| No |
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| No |
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| Yes |
| Comments: The intent of this question is not clear. NESCOE expects that the STD’s efforts to clarify definitions by seeking technical justifications will necessarily lead to revisions to some of those terms, including the base BES definition itself. For this reason, NESCOE repeats its comment in question 1 that to avoid any misunderstanding, the scope should explicitly state the Phase 2 work is sufficiently broad such that the language developed in Phase 1 remains open and subject to restructuring and revision based on the technical analysis being undertaken. In other words, the scope should clarify that the analysis in Phase 2 is not being undertaken simply to provide technical justifications for the BES language already approved by the NERC Board of Trustees in conjunction with Phase 1. |
| No |
| Comments: Again, NESCOE believes this question is unclear. Following clarification of the issue, NESCOE may provide comments at a future time on regional variances required in the New England region. |
| Yes |
| Comments: NESCOE anticipates that the results of this project will entail multiple changes to numerous existing business practices, including impacts related to maintenance and operation as well as construction of new facilities required to comply with the approved BES definition. Maintenance will likely be impacted due to the frequency and extent of maintenance required. Operations may be impacted in several ways. For example, there may be increased outages scheduled to enable new construction of upgrades required to meet BES requirements. Indeed, extensive construction outages to comply with the BES could ironically reduce reliability due to extending exposure periods of a weakened system and could impose increased costs by leading to “must run” units dispatched out of economic merit. Construction could be extensive. |
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| Group |
| Western Area Power Adminstration |
| Brandy A. Dunn |
| No |

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| We urge the SDT to go back to the drawing board on the basis that the proposed BES definition micro-manages sound planning and operational standards and their supporting system studies. We suggest a straight forward bright-line delineation of the BES for any aggregate generation facility or single transmission circuit element which meets one or both of the following criteria: 1) 100 kV and 100 MVA capability or 2) a designated transfer path or flow gate. If an element is not capable of 100 MVA or is not a designated transfer path or flow gate, it should be considered sub-transmission or distribution. The BES definition should be reserved for the backbone transmission/generation system that is used for bulk power transfer to sub-transmission and distribution. Typical surge impedance loading (SIL) of a 100 kV system is on the order of 50 MVA, without supplemental VAR support. With robust supplemental VAR support, the SIL of a 100 kV system is on the order of 100 MVA and is more likely being used for bulk power transfer. Consideration should be given to defining Supporting Electrical System (SES) as sub-transmission and distribution, which should be held to a lower 'bar' of reliability standards accordingly. This approach would more adequately account for both regional variances and utility practices while maintaining the reliability of the BES to transmit and generate bulk power for the grid. Therefore, any element above the bright-line 100kV/100MVA delineation should be considered part of the BES for the purpose of bulk power transfer and any element below the 100kV/100MVA delineation should be considered sub-transmission or distribution, i.e. Supporting Electrical System (SES). A comprehensive cost-benefit analysis should be utilized to justify the cost-benefit-ratio of the perceived reliability need and/or improvement to the BES. These results should be presented to the rate base customer prior to adoption and inclusion of proposed 100 kV facilities into the BES definition. The base rate customer needs to be aware of 'why' and 'how' Inclusions and Exclusions to the BES definition are determined. We feel that such a due process should be imperative. 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. Caution: Lack of existing technical studies/documentation/justification should not influence the schedule or willingness to address the need to provide said justifications prior to adoption of any final language. |
| No |
| Identification of Real and Reactive Power requirement to securely support the BES are already addressed in both planning and operations standards. If additional language is needed to prevent PV or PQ collapse, it should occur in those standards. |
| No |
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| No |
| We believe this is moot and would provide minimal insight. Other economic and technical studies should receive the available resources. |
| No |
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| No |
| "Supports" needs definition. If "supports" is intended to include equipment that provides needed VAR support or general stiffness and robustness to the system, the TPL assessment studies already determine which equipment elements "support" the BES. Again, consider a bright-line delineation of the BES for any aggregate generation facility or single transmission circuit element which meets one or both of the following criteria: 1) 100 kV and 100 MVA capability or 2) a designated transfer path or flow gate. If an element is not capable of 100 MVA or is not a designated transfer path or flow gate, it should be considered sub-transmission or distribution. Elements found to be 'triggers' of BES failures should not be considered an integral part of the BES definition, unless the element was an integral part of the failure. For example, if a fault on sub-transmission destabilizes the BES due to failure of generator stabilizer(s), the sub-transmission event was the trigger of the BES element failure, i.e. the generator stabilizer(s). Other operational and planning standards already determine which equipment is needed for "support" to maintain a secure BES. Otherwise, this concept is vague and micromanages sound planning studies and operational criteria. We believe this is moot and would provide minimal insight. Other economic and technical studies should receive available resources. Consideration should be given to defining Supporting Electrical System (SES) as sub-transmission and distribution, which |

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| should be held to a lower ‘bar’ of reliability standards accordingly. This approach would more adequately account for both regional variances and utility practices while maintaining the reliability of the the BES to transmit and generate bulk power for the grid, i.e. 100kV/100MVA and above is considered part of the BES for the purpose of bulk power transfer. |
| No |
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| No |
| Not sure what is intended here. An automatic interrupting device sounds vague and could include anything from a fuse, to a circuit breaker, recloser, spark gap, etc. We believe this is moot and would provide minimal insight. Other economic and technical studies should receive available resources. |
| No |
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| No |
| The is adequately covered with CIP and EOP standards and would likely create micromanaging overlap. We believe this is moot and would provide minimal insight. Other economic and technical studies should receive the available resources. |
| No |
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| Yes |
| We suggest a straight forward bright-line delineation of the BES for any aggregate generation facility or single transmission circuit element which meets one or both of the following criteria: 1) 100 kV and 100 MVA capability or 2) a designated transfer path or flow gate. If an element is not capable of 100 MVA or is not a designated transfer path or flow gate, it should be considered sub-transmission or distribution. The BES definition should be reserved for the backbone transmission/generation system that is used for bulk power transfer for sub-transmission and distribution. Typical surge impedance loading (SIL) of a 100 kV system is on the order of 50 MVA, without supplemental VAR support. With robust supplemental VAR support, the SIL of a 100 kV system is on the order of 100 MVA and is more likely being used for bulk power transfer. |
| No |
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| No |
| This is adequately evaluated under other standards, i.e. TPL, and tends to micromanage both planning standards and operational criteria. Confining concepts like this could very well reduce overall reliability. We believe this is moot and would provide minimal insight. Other economic and technical studies should receive available resources. |
| No |
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| No |
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| Yes |
| Keep the focus on "bulk power transfer" and clear a way for defining sub-transmission and distribution outside of BES. We urge the SDT to re-evaluate the intent and scope of the BES definition and give adequate consideration to the cost-benefit of the end user. |
| Yes |
| A significant regional variance of vast rural areas of the country are not adequately considered. These areas experience a very high mean-time-between-failure (mtbf) rate and a disproportionately high cost of 'reliability' to meet standards more appropriate for densely populated urban areas. Building rural areas to urban standards increases the cost to the end user disproportionately and dramatically as compared to industrial and/or urban areas, for marginal improvement to the MTBF rate. |
| Yes |
| Consequential rate increases to the end user resulting from overreach of the BES definition, including inadequate consideration of regional differences will need to be justified to the customers, public service commissions and other public watchdog groups without their input and/or appropriate |

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| deliberation prior to the necessity to change relative business practices. |
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| Individual |
| Kirit Shah |
| Ameren |
| Yes |
| We believe that technical analysis/justification should be used for BES definitions and for inclusion and exclusion criteria. However, a complete technical justification for the definition or exclusions may not be possible in all cases which can also be applicable to all situations. Therefore, we suggest an approach similar to the CIP-002-4 "bright line" determination of critical assets accompanied by a document describing technical and other factors used by the SDT. In this regard, we suggest that the SDT start with 100kV as the brightline criteria with exclusions for radial connections and distribution substation transformers with less than 100kV secondary terminal voltage. |
| Yes |
| Please see our response to Question #1. |
| No |
| We do not know of any examples for general application that would guide the SDT. |
| No |
| We believe the benefits of an interconnected system have been well documented and NERC should be able to provide them. |
| No |
| Please see our response above. |
| No |
| Please provide clear definition for what is meant by “supports” so that there is no ambiguity in determining what equipment’s are to be considered. For "technical justification", see our response to question #1. |
| No |
| We do not know of any examples for general application that would guide the SDT. |
| No |
| Clearly such radial facilities excluded in E1 do not affect the BES, thus including its automatic interrupting device would add burden without benefit. Similarly, the Local Networks of E3 support reliability to the network load but do not affect the BES. We are not aware of any significant BES events caused by the failure of such devices. |
| No |
| We are not aware of any significant BES events caused by the failure of such devices. |
| No |
| As stated in our response in Question #1, the SDT should limit its definition to those blackstart facilities connected at 100 kV and above. The inclusion of cranking paths may introduce unnecessary complication to the definition and lead to the possible misclassification of elements as BES that would not have a significant effect on BES reliability. |
| No |
| We do not know of any examples for general application that would guide the SDT. |
| Yes |
| Please see our response to question #1. |
| No |
| We do not know of any examples for general application that would guide the SDT. |
| Yes |
| We believe that if power can flow both ways (to and from) a Local network (>100kV), except during blackstart conditions, then the local networks are part of the BES and should not be excluded. |
| No |
| The maximum allowable flow will need to be determined by technical justification and input from |

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| industry. |
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| No |
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| No |
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| None |
| Individual |
| Keith Morisette |
| Tacoma Power |
| No |
| Tacoma Power supported the creation of the Phase 2 project, as identified during the BES definition process. The Standards Drafting Team (SDT), the industry, the reliability entities, and the regulating agencies have all expended considerable effort in the BES definition process and support a definition that Tacoma Power finds workable and strongly supports. However, Tacoma Power is concerned that the Phase 2 scope has been written too broad and could unwind some of the consensus achieved in the BES definition that was submitted by the industry. Tacoma Power would like the scope of Phase 2 to be limited to the technical justifications of the thresholds and methodologies that will be used in the exception process of the BES definition. Tacoma Power supports the Snohomish PUD draft comments for this question, and specifically, the following four issues for which the SAR is proposed to provide “greater clarity.” First, we support the SAR’s intent to better define the relationship between the BES definition and the NERC Statement of Compliance Registry Criteria (“SCRC”). In our view, the SCRC is intended only to identify the Elements that might be subject to registration. As the SCRC itself states, the SCRC is intended only to identify “candidates for registration.” SCRC at p.3, § 1. On the other hand, the BES Definition and associated Exceptions process is intended to definitively identify Elements that are part of the BES. We are concerned that the distinction between identifying candidates for registration under the SCRC and definitively identifying Elements to be classified as BES has sometimes been lost in the SDT process. For example, the thresholds specified to identify candidates for registration under the SCRC were imported into the BES definition, but there has never been a technical analysis to demonstrate the validity of these thresholds for identifying BES Elements. Secondly, we support clarification of the term “non-retail generation.” The meaning of this term is not clear – it could refer to wholesale generation, to behind-the-meter generation owned by an end-use customer, or some other concept. Many commenters during Phase 1 identified this term as one that should be clarified. The SDT responded “Non-retail generation is a widely used and understood term and is not defined here.” We are encouraged that the proposed SAR would revisit this question. The number of comments related to this item makes it is clear the term is not widely understood, and we wish to ensure the regulated community, the Registered Entities, NERC, and FERC all use the same definition. We also suggest that the definition should reside either in the BES definition document or separately in the NERC Glossary. Thirdly, we support an effort to further clarify the reference to “dispersed power resources” in Inclusion I4. We are also concerned Inclusion I4, in its current form, as proposed, could have unintended consequences and improperly classify local distribution systems as BES in certain circumstances. This is because multiple distributed generation units could render a local distribution system a “collector system” and the entire system the equivalent of an aggregated generation unit, causing the local distribution system to be improperly denied status as a LN. If many different distributed generation units are connected to a local distribution system, in many scenarios not more than a few of those units would fail simultaneously, and it is therefore unlikely that multiple generation units would produce a measureable impact on the interconnected bulk transmission system, especially if the units individually do not otherwise exceed the materiality threshold to be established by the SDT in Phase 2. Further, we are concerned that, if small distributed generation units become the industry norm, Inclusion I4 could unintentionally sweep in local distribution systems, especially where local policies favor the growth of small solar or other renewable generation systems for public policy reasons. This is of particular concern in a number of states that have |

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| adopted policies favoring construction of small, dispersed, distribution-level renewable generation. Finally, we support the SDT in defining the points of demarcation between the BES and non-BES facilities. This is a critical question for clearly defining the compliance obligations of Registered Entities. We note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. |
| Yes |
| Tacoma Power supports the SDT and encourages the development of a technical justification for real and reactive resource thresholds and methodologies to be used in the exception process of the BES definition. Currently, the real and reactive resource are not determined by technical justification or methodology. Determinations for inclusion and exclusion of elements from the BES definition must demonstrate that only the identified elements are necessary for the operation of the BES and needed to maintain system reliability. The inclusion of elements cannot be determined solely for administrative convenience or desirability. Tacoma Power supports the Snohomish PUD draft comments for this question. The Phase 1 BES Definition contains at least three resource-related thresholds that require technical justification: (1) generation resources and Real Power and Reactive Power resources connected “at a voltage of 100 kV or above”; (2) generating resources with an individual nameplate capacity of “greater than 20 MVA”; and, (3) generating resources with an aggregate plant/facility rating of “greater than 75 MVA.” We emphasize that, under Section 215 of the Federal Power Act (“FPA”), a technical justification must be provided to demonstrate that it is “necessary” to include generation and reactive power resources meeting these thresholds in the bulk system. Specifically, FPA Section 215 defines “bulk-power system” to mean “facilities and control systems necessary for operating an interconnected electric energy transmission network” and, specifically with respect to generation facilities, includes only those generators “needed to maintain transmission system reliability.” 16 U.S.C. § 824o(a)(1). Accordingly, for purposes of defining the BES, it is not sufficient to demonstrate merely that it may be desirable or administratively convenient to include generators or reactive power resources meeting specific thresholds in the BES. Rather, the thresholds must be supported by technical justification showing that generators and reactive power resources meeting the thresholds are “necessary” for reliable operation of the bulk transmission system. Given these statutory constraints, we suggest that the SDT should consider either moving away from the threshold approach or else providing a process by which generators that meet the specified threshold but are demonstrably unnecessary for reliable operation of the bulk system can be excluded from the BES. It may be necessary to adopt this approach because the importance of a particular generator or reactive power resource may vary depending on, for example, where that resource is located within the electric system. For example, a 25-MW generator located at or near a constrained transmission path may play a key role in keeping that constrained path operating, whereas a generator of the same size located within a large local distribution network is likely to have little or no impact on the bulk system. If a 25-MW generator is embedded within the distribution network of a utility with an average load of 1,000 MW, it is unlikely that power from that generator would ever escape the distribution network, let alone have an impact on the bulk system. Even if the generator suffered a fault, the loss of such generation within such a large distribution system would, from the perspective of its impact on the bulk transmission network, likely be indistinguishable from changes in demand of the distribution system arising from ordinary load variation. |
| Yes |
| Snohomish County PUD produced a document entitled “White Paper: A Performance-Based Exemption Process to Exclude Local Distribution Facilities from the Bulk Electric System” (April 2011). We understand Snohomish has attached that document to its comments on the Phase 2 SAR. |
| No |
| Tacoma Power supports a BES definition that determines and identifies elements that are “necessary” for the operation of the BES and needed to maintain system reliability, and not be concerned whether those elements are contiguous or non-contiguous. Tacoma Power supports the Snohomish PUD draft comments for this question. The SDT should be focusing on how to comply with the statute, namely whether the specific “facilities and control systems” at issue are “necessary for” operating the bulk interconnected transmission network and whether energy from generation facilities is “needed to |

maintain transmission system reliability." 16 U.S.C. § 824o(a)(1). We are concerned that the SDT may get off course by focusing on a question with no statutory basis – whether the BES should be "contiguous" – rather than on the statutory questions. If the SDT focuses its efforts on these critical statutory tests, the resulting BES definition may be either "contiguous" or "non-contiguous," but it will have met the relevant statutory criteria. At the same time, by including only those facilities in the BES that are necessary to operation of the interconnected bulk system, a focus on the statutory questions is likely to minimize the unnecessary compliance burdens that will result from an overly-broad BES definition. In short, the SDT should not address the "contiguous/non-contiguous" question directly, but should focus on the question of what facilities are "necessary" for the operation of the bulk system, and let results speak for themselves on the "contiguous/non-contiguous" question. We also note that the "contiguous/non-contiguous" question seems to be premised on two ideas of questionable validity: (1) that any Element that might affect bulk system reliability must be included in the BES or escape the reliability standards; and, (2) that if an Element is part of the BES, it must be connected to other BES Elements in order to ensure reliable operation of the bulk system. There is no basis for concluding that an Element must be defined as part of the BES to ensure reliability. On the contrary, FPA Section 215 requires "users" of the BES to comply with reliability standards, as well as "owners and operators" of BES facilities. Accordingly, as long as it can be demonstrated that it is "necessary for" users to comply with a particular reliability standard in order to ensure reliable operation of the interconnected bulk transmission system, then BES users, as well as owners and operators, can properly be subject to reliability standards. It is for this reason that BES users such as distribution utilities can be required to meet, for example, scheduling requirements designed to ensure reliable operation of the BES. Nor is there any basis for concluding that reliable operation of the bulk transmission system will be compromised if every BES Element is not connected to another BES Element. NERC's Standards Drafting Team for Project 2010-07 and its predecessor, the Ad Hoc Group for Generator Requirements at the Transmission Interface (collectively, the "GO-TO Task Force") have already examined this question in some detail in the context of determining whether the facilities connecting BES generators to the interconnected BES transmission system must also be classified as BES. In other words, these NERC teams addressed the question whether a "contiguous" BES is necessary so that the interconnection factilities connecting BES generators to the bulk transmission system must also be classified as BES facilities. After examining the issue in detail, the GO-TO Task Force concluded that interconnection facilities "are most often not part of the integrated bulk power system, and as such should not be subject to the same level of standards applicable to Transmission Owners and Transmission Operators who own and operate transmission Facilities and Elements that are part of the integrated bulk power system." White Paper Proposal for Information Comment, NERC Project 2010-07: Generator Requirements at the Transmission Interface, at 3 (March 2011) (available at: http://www.nerc.com/docs/standards/sar/2010-07_White_Paper_Proposal_for_Informal_Comment.pdf). Rather than classifying generation interconnect facilities as part of the BES, and requiring them to comply with the entire suite of reliability standards applicable to BES facilities, the GO-TO Task Force concluded that reliability was ensured if these facilities complied with a handful of reliability standards, primarily related to vegetation management, and that the bulk interconnected system could be protected without unduly burdening the owners of such interconnection systems. Therefore, there is no reason, according to the GO-TO Team, that dedicated high-voltage interconnection facilities must be treated as "Transmission" and classified as part of the BES in order to make reliability standards effective. See Final Report from the NERC Ad Hoc Group for Generator Requirements at the Transmission Interface (Nov. 16, 2009) (available at: http://www.nerc.com/docs/standards/sar/GO-TO_Final_Report_2009Nov16.pdf). On the other hand, there is considerable danger in over-regulation if a "contiguous" BES is adopted. UFLS and UVLS relays provide a prime example. Such relays are generally embedded in distribution system substations rather than being interconnected directly in transmission substations or other transmission equipment. But, if the SDT concludes that UFLS and UVLS relays need to be defined as part of the BES and also concludes that a contiguous BES is required, the result would be that large segments of the nation's distribution systems would be classified as BES. This would violate the FPA, which unequivocally requires "facilities used in the local distribution of electric energy" to be excluded from the BES. 16 U.S.C. § 824o(a)(1). It is also unnecessary because the FPA provides two avenues for ensuring that UFLS and UVLS relays are subject to reliability standards, neither of which requires a contiguous BES. First, distribution providers, as "users" of the transmission system, may be required to set their UFLS and UVLS relays in accordance with norms set by the relevant RE as a condition of using the bulk system because

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| proper operation of such relays is “necessary for” reliable operation of the bulk transmission system. Second, UFLS and UVLS relays can be defined as part of the BES. As long as the BES is non-contiguous and owners of such relays are subject only to standards relevant to UFLS and UVLS rather than standards appropriate to other kinds of equipment, the fundamental goal of reliability will have been achieved without being exposing to unnecessary compliance costs. Finally, we suggest that, rather than considering whether the BES should be contiguous or non-contiguous, the SDT should focus on developing principles for use in the Exceptions/ Inclusions process that would define whether an Element is “necessary for” the operations of the BES. Where the principles would provide for non-contiguous BES Elements, such non-contiguous Elements should be included in the BES only through the Inclusion process. |
| No |
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| No |
| Tacoma Power supports the Snohomish PUD draft comments for this question. In the Scope statement, the question is presented as: “Determine if there is a technical justification for the equipment which ‘supports’ the reliable operation of the BES but is installed on the distribution system.” If the question is formulated in this way, Tacoma Power opposes including this question in Phase 2 because FPA Section 215 is unequivocal in excluding from the BES “facilities used in the local distribution of electric power,” 16 U.S.C. § 824o(a)(1). If the issue is whether distribution facilities should be included in the BES, the SAR contemplates a plain violation of the statute and it should be rejected. Tacoma Power is concerned that the question may not comport with the statute because the FPA provides authority to regulate facilities only if they are “necessary for” operation of the interconnected bulk transmission system. 16 U.S.C. § 824o(a)(1). Accordingly, the relevant question is whether facilities are “necessary for” reliable operation of the BES, not whether they “support” operation of the BES. To the extent the question contemplates classifying facilities that are not “necessary for” operation of the bulk transmission system, it again threatens to overstep the statutory authority provided in Section 215 of the FPA. We note that the SDT’s task is limited to defining the BES. To the extent the question contemplates a technical analysis of whether non-BES facilities should be subject to reliability standards, the question is beyond the scope of the SDT’s mission. At most, the SDT could only make recommendations on these issues, and we do not believe this is a good use of the SDT’s limited resources. |
| No |
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| No |
| Tacoma Power understood this subject was discussed during Phase 1, and sees no reason to reopen it. Further, the requirement to have automatic fault-interrupting devices (“AFID”) at the tap points to take advantage of E1 or E3 is unlikely to provide any benefit to the BES, and the lack of such a device is unlikely to negatively impact the BES. While there may be exceptions, if a Registered Entity can show the radial line or Local Network does impact the BES, they can seek an Inclusion of the relevant radial line or Local Network. |
| No |
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| No |
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| Yes |
| While Tacoma Power responded in Question 1 that we do not want to unwind any of the consensus achieved in the Phase 1 BES definition that was submitted by the industry, we do support the SDT readdressing this issue on a regional basis with a regional variance. We reiterate the following arguments in Question 11. Tacoma Power supports the Snohomish PUD draft comments for this question. Many entities in the WECC region have maintained that a threshold of at least 200 kV, rather than 100 kV, should be used for the WECC region. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because |

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| they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities, Tacoma Power believes there is no technical justification for including facilities operating at 100-kV in the BES. Tacoma Power therefore strongly supports the SDT's willingness to re-examine this issue from a technical perspective. We note, further, that differences between the Eastern Interconnection and the Western Interconnection may well justify a different threshold for the two interconnections. There are several differences between the two interconnections that may justify different treatment. For example, the Western transmission system generally links isolated generators with load centers that are located far from the generator using long transmission lines, while generation and load in the Eastern system are usually much closer geographically and the system is therefore much more networked. In addition, the Western system is generally stability-limited, while the Eastern system is generally thermally-limited. |
| Yes |
| Tacoma Power supports the Snohomish PUD draft comments for this question. In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100-kV or 200-kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend its work to the SDT as a good starting point for its Phase 2 analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase 2 in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200 kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230 kV, 345 kV, and 500 kV as typical bulk transmission voltages. Facilities operating below 230 kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200 kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100 kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230 kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100 kV and 200 kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200 kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200 kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200 kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200 kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200 kV is significantly below that of the 200-300 |

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| kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200 kV, while lines operating in the range of 100-200 kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100-kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located in the WECC. Using a 200-kV threshold with an inclusion mechanism to identify the minority of 115-kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| Yes |
| Tacoma Power is concerned that the Local Network (LN) exclusion in the BES Definition resulting from the Phase 1 Standards Development process contains an unnecessary limitation requiring that power "flows only into the LN." As long as the power flow is generally into the LN and the LN is not operated as part of the bulk transmission system, the LN should be excluded from the BES. It makes little sense for the LN to be included as part of the BES if power flows from the LN onto the bulk system only in inconsequential amounts or only during unusual contingencies. Tacoma Power supports technical analysis of this issue. While we support technical analysis of this issue, we are concerned that the reference to "certain conditions" suggests that the technical analysis will not focus on LNs operating as intended, but will delve into contingencies, even contingencies that are extremely remote. We urge the SDT to analyze this question for LNs operated as intended under normal conditions. If, in unusual circumstances, flows might emanate from an LN that do not emanate under normal circumstances, the relevant Registered Entity, Transmission Operator, or Reliability Coordinator can use the Inclusion process to seek inclusion of that LN in the BES if it can demonstrate the LN has a substantial impact on operation of the bulk transmission system under reasonably foreseeable contingencies. |
| No |
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| Yes |
| Tacoma Power supports the Snohomish PUD draft comments for this question. As noted in our response to Question 1, we agree that Phase 2 should address the question of defining the points of demarcation between the BES and non-BES Elements. We believe that demarcation is a technical question, and therefore believe Phase 2 should approach demarcation as a technical question rather than as merely a clarification. If the SDT puts together a technical record supporting its approach to demarcation, we believe the resulting standard will be more likely to survive regulatory review. We again note that the WECC BES Definition Task Force has already devoted considerable effort to defining the point of demarcation for many different facility configurations. See Demarcation Principles for Inclusion in Proposal 6, App. C to WECC-0058, Proposal No. 6 of WECC BES Definition Task Force (Feb. 16, 2011) (available at: http://www.wecc.biz/Standards/Development/BES/default.aspx). We recommend that the SDT use this work as a starting point for its analysis. We also believe that additional work is necessary to define the relationship between the Exclusions and Inclusions. Some of the Inclusions and Exclusions as currently provide language that explains how they operate if an Element falls into both an Exclusion and Inclusion. For example, Inclusion I1 specifies that certain transformers must be included in the BES "unless excluded under Exclusion E1 or E3." This makes clear that transformers operating within a radial or Local Network subject to exclusion under Exclusions E1 or E3 are not part of the BES even if they otherwise would be included as a result of Inclusion I1. We are concerned, however, that there is no clear general rule on how to classify an Element that meets both an Inclusion and an Exclusion. For example, a capacitor located on radial line, and therefore excluded by operation of Exclusion E1 might nonetheless meet the requirements for inclusion under Inclusion I5. A method for resolving this conflict should be spelled out in the definition so that future disputes about conflicting Inclusions and Exclusions can be avoided. As a starting point, we suggest that the phrase at the end of Inclusion I1 ("unless excluded under Exclusion E1 or E3") be added to Inclusions I4 and I5, so that all non-generation equipment that is located on a radial or in a Local Network is excluded consistent with the intent of Exclusions E1 and E3. Similarly, the phrase "unless excluded under Exclusion E2" should be added at the end of Inclusion I2 so that definition makes clear that customer-owned, behind-the-meter generation is always excluded under Exclusion E2. While the relationship |

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| between the Inclusions and Exclusions might reasonably be viewed as just a clarification of the current definition, we note it here because we believe additional technical analysis may be needed to resolve potential conflicts between Inclusions and Exclusions, at least in some circumstances. In addition, we advocate that the SDT prepare flow-through diagrams that graphically represent how particular Elements will be handled under the BES Definition, both as a matter of guidance to regulated entities and as a means of identifying potential conflicts between Inclusions and Exclusions that should be addressed by the SDT. |
| Yes |
| As reflected in our response to Question 1, Tacoma Power is concerned that the Phase 2 scope has been written too broad and could unwind some of the consensus achieved in the BES definition that was submitted by the industry. Hence, while we believe that the SDT might usefully consider certain clarifications in the definition as formulated at the end of Phase 1, we recommend that the SDT delve into these questions only if there is near-unanimous agreement among the interested parties that the SDT should do so. If there is near-unanimous agreement that these clarifications should be addressed in Phase 2, we recommend the following clarifications: 1) With respect to Inclusion 1, which provides that Transformers are included in the BES "if the primary terminal and at least one secondary terminal" are operated at 100 kV or higher. As we understand it, the BES intends to include transformers only if both the primary and secondary terminals operate at 100 kV or above, which is why the definition uses the word "and" ("the primary and secondary terminals"). We support this approach since it would exclude transformers where the secondary terminals serve distribution loads, and which therefore function as distribution rather than transmission facilities. We believe the SDT's intent would be clarified by adding a sentence at the end of Inclusion 1 that reads: "Transformers with primary terminals that operate at or below 100 kV are not part of the BES. Transformers with no secondary terminals operating at or above 100 kV are also excluded from the BES." This language will help ensure that there is no controversy over whether the SDT's use of the word "and" in the phrase "the primary and at least one secondary terminals" was intentional. 2) We also believe the clauses at the end of Inclusion 2 are somewhat confusing and that greater clarity would be achieved by changing ". . . including the generator terminals through the high-side of the step-up transformer(s) connected at a voltage of 100 kV or above" so that the Inclusion covers transformers with terminals "connected at a voltage of 100 kV or above, including the generator terminal(s) on the high side of the step-up transformer(s) if operated at a voltage of 100 kV or above." As noted in our answer to Question 9, we also believe that language should be added to Inclusion 2 making clear how an Element will be handled if it falls both within this Inclusion and within the Exclusions. The same is true of the other Inclusions that lack such language. 3) With respect to Inclusion I4, which addresses dispersed power producing resources, we suggest adding at the end of the Inclusion the phrase ". . . unless the dispersed power producing resources operate within a radial system meeting the requirements of Exclusion E1 or a Local Network meeting the requirements of Exclusion E2." This language, which parallels the language included at the end of Inclusion I1, would make clear that dispersed small-scale generators scattered throughout a radial system or Local Network serving retail load would not convert the radial system or Local Network into a BES system, even if the aggregate capacity of those small generators exceeds the relevant threshold. 4) With respect to Inclusion I5, which concerns devices providing or absorbing Reactive Power, Tacoma Power is concerned that there is no threshold specified for Reactive Power devices that would be considered part of the BES. This is inconsistent with the approach taken in the balance of the definition, where thresholds are specified for generators and other types of power producing devices. It is also inconsistent with the approach taken to real power generators, where the SAR proposes to provide a technical analysis of the threshold voltage at which such devices should be considered part of the BES. Tacoma Power believes the appropriate threshold for inclusion or exclusion of Reactive Power devices from the BES should be subject to the same technical analysis that will cover generators in the Phase 2 process. 5) With respect to Exclusion E1, which covers radial systems, we believe two changes would greatly improve the clarity of the language. First, the term "transmission Elements" in the initial paragraph should be changed to "Elements." Radial systems are not transmission systems and including the word "transmission" in the radial system exclusion is therefore unnecessary and confusing. Second, the "Note" at the end of the Exclusion states that "a normally open switching device between radial systems" will not serve to disqualify the radial from exclusion under Exclusion 1. While Tacoma Power strongly supports the note in concept, we suggest including the relevant language in a separate subparagraph (d), which would read: Normally-open switching devices between radial elements does not affect this exclusion. This will make clear that a radial system with more than one normally-open |

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| switch connecting it to another radial system is still a radial system. From the perspective of the BES Definition, the key question is whether switches operating between radial systems are normally open, not whether there is more than one normally-open switch. Including this language in a separate paragraph rather than a note will make clear that it bears equal importance to other portions of the Exclusion. We also suggest eliminating the phrase “as depicted and identified on system one-line diagrams” from the language because the presence of normally-open switches is the substantive concern and the language suggests that even minor errors in the diagrams could produce potentially serious regulatory consequences. 6) With respect to Exclusion 2, which addresses generation owned by a retail customer, Tacoma Power is concerned that Exclusion 2 will place local distribution utilities in a difficult position because, under Exclusion 1 or Exclusion 3 as drafted, they could lose their status as a radial system or a Local Network through the actions of a customer constructing behind-the-meter generation, if that generation exceeds the specified 75 MVA threshold. With respect to radial systems, the appearance of behind-the-meter generators could cause the radial system to exceed the thresholds specified in subparagraphs (b) and (c) of Exclusion 1 through no fault of the radial system. Similar, a Local Network could lose its status because behind-the-meter generation could be of sufficient size that power moves into the interconnected grid in certain hours or under certain contingencies, rather than moving purely onto the Local Network, as required in subparagraph (b) of Exclusion 3. We suggest that this issue be addressed along with the larger issue of appropriate voltages for generation resources. 7) With respect to the Local Network (LN) exclusion, Exclusion E3, Tacoma Power believes further improvement of the language could be achieved with additional modifications and clarifications. With respect to the core language of Exclusion 3, we believe the language making a “group of contiguous transmission Elements operated at or above 100 kV” the starting point for identifying a LN would be improved by deleting the term “transmission” from this phrase. This is so because LNs are not used for transmission and the use of the term “transmission Elements” is therefore both confusing and unnecessary. Further, any definitional value that is added by using the term “transmission Elements” is accomplished by using that term in the core definition, and there is no reason to carry the term through in the Exclusions. Tacoma Power also believes that subparagraphs (a) and (b) are redundant in the sense that whatever protection is offered by the generation limit in subparagraph (a) is duplicated by the limit in subparagraph (b) requiring no flow out of the LN. We believe the SDT can eliminate subparagraph (a) of Exclusion 3 and simply rely on subparagraph (b) because if power only flows into the LN even if it interconnects more than 75 MVA of generation, the interconnected generation interconnected will have no significant interaction with the interconnected bulk transmission system. It will only interact with the LN. And, with the advent of distributed generation, it is easy to foresee a situation in which a large number of very small distributed generators are interconnected into a LN, so that the aggregate capacity of these generators exceeds 75 MVA. However, because the generators are small and dispersed and, under the criterion in subparagraph (b), would be wholly absorbed within the LN rather than transmitting power onto the interconnected grid, those generators would not have a material impact on the grid. Finally, Tacoma Power believes that both subparagraphs (a) and (b) of Exclusion 3 could be safely eliminated as long as subparagraph (c) is retained. Subparagraph (c) makes a LN part of the BES if it is classified as a Flow Gate or Transfer Path. Flow Gates and Transfer Paths are, by definition, the key facilities that allow reliable transmission of bulk electric power on the interconnected grid. If a LN has not been identified as either a Flow Gate or a Transfer Path, it is unlikely the LN is necessary for the reliable transmission of electricity on the interconnected bulk system. |
| Yes |
| While Tacoma Power responded in Question 1 that we do not want to unwind any of the consensus achieved in the Phase 1 BES definition that was submitted by the industry, we do support the SDT readdressing this issue on a regional basis with a regional variance. We reiterate the following arguments in Question 7, above. Many entities in the WECC region have maintained that a threshold of at least 200 kV, rather than 100 kV, should be used for the WECC region. This is because most 115-kV facilities in the West operate as distribution facilities rather than transmission facilities. It therefore makes sense for 200 kV to be used as the threshold and then focus the definition’s inclusion mechanisms to identify those facilities operating below 200-kV that are integral to the interconnected bulk system because they are, for example, identified in the WECC Path Rating Catalog. Except for this relatively small class of 115-kV facilities, Tacoma Power believes there is no technical justification for including facilities operating at 100-kV in the BES. Tacoma Power therefore strongly supports the SDT’s willingness to re-examine this issue from a technical perspective. We note, further, that differences between the Eastern Interconnection and the Western Interconnection may well justify a |

different threshold for the two interconnections. There are several differences between the two interconnections that may justify different treatment. For example, the Western transmission system generally links isolated generators with load centers that are located far from the generator using long transmission lines, while generation and load in the Eastern system are usually much closer geographically and the system is therefore much more networked. In addition, the Western system is generally stability-limited, while the Eastern system is generally thermally-limited. In connection with its efforts to develop a refined BES definition for the Western Interconnection prior to FERC's issuance of Order No. 743, the WECC Bulk Electric System Definition Task Force ("BESDTF") expended considerable effort on historical and technical analysis to determine whether a 100-kV or 200-kV threshold is more appropriate for the Western Interconnection. See Western Electric Coordinating Council's Bulk Electric System Definition Task Force ("BESDTF"), Initial Proposal and Discussion, at pp. 11-18 (posted at on May 15, 2009) available at: http://www.wecc.biz/Standards/Development/Lists/Request%20Form/DispForm.aspx?ID=21&Source=/Standards/Development. We commend its work to the SDT as a good starting point for its Phase 2 analysis of this issue. We set forth a few of the BESDTF's key conclusions on this issue, both to emphasize the need for the SDT to re-examine this issue in Phase 2 in order to place the BES Definition on the firmest possible technical grounds, and also to underscore the quality of the analysis already performed by the BESDTF. For example, after evaluating the topology of the Western system, the BESDTF observed: In the West, remote generation is a significant portion of most entities' resource portfolios. Transmission facilities, typically greater than 200 kV, were constructed to get that remote generation to the load center . . . Due to the relatively long distances from remote resources to the load, entities recognized a need for higher voltage transmission lines and adopted 230 kV, 345 kV, and 500 kV as typical bulk transmission voltages. Facilities operating below 230 kV in the WECC are therefore typically associated with local distribution rather than the transfer of bulk power: These 100-200 kV facilities . . . are, in almost all cases, configured in such a way as to serve as a sub-transmission delivery system to a geographically and electrically confined distribution system. They are typically operated as local area loops to provide supply redundancy to the distribution stations which they serve, but in general do not carry bulk system transfers between systems or between Balancing Authority Areas. . . . 100 kV facilities throughout the Western Interconnection, other than the limited few which comprise a Transfer Path, carry insignificant amounts of bulk power flow. In other words, the flows on these facilities amount to the sum of the distribution load being served in the area, and they do not carry any appreciable portion of bulk power transfers across Balancing Authority Areas or between Balancing Authority Areas. The BESDTF also noted that future transmission facilities constructed in the WECC are likely to operate at voltages of 230 kV or above. It seems unlikely that any new bulk transmission service would be constructed at a voltage between 100 kV and 200 kV. The WECC Transmission Expansion Planning Policy Committee's (TEPPC) 2009 Synchronized Study Program (Study Program) identifies 46 transmission additions in the planning stages. The Study Program information is drawn from study requests submitted to TEPPC, project websites, submissions by project sponsors and PCC logs for Regional Project Reviews (also called Phase 0) and the logs for Phases 1, 2 and 3 of the Path Rating Process. All 46 proposed transmission additions are 200 kV or higher voltage. The BESDTF backed up these observations with technical analysis, starting with an examination of the WECC Path Rating Catalog. As noted by the BESDTF, the Path Rating Catalog identifies 70 "Transfer Paths," the majority of which are operated at voltages exceeding 200 kV: Of the 70 Transfer Paths, 46 of them, or 66%, are entirely operated at greater than 200kV. These 46 Transfer Paths, however, account for over 78% of the total transmission capacity of the group of Transfer Paths. More importantly, there are 253 unique transmission elements comprising these 70 Transfer Paths, and of those, 211 of them, or 83%, are above 200 kV. In addition, the BESDTF examined data from the WECC 2009 HS3 power flow base case. This data, like the data from the Path Rating Catalog, demonstrates that lines operating in the 100-200 kV range have a small impact on transmission in the Western Interconnection. The BESDTF observed: "As can be seen, the nominal average capacity of lines below 200 kV is significantly below that of the 200-300 kV range (13.3 % and 28.1% respectively). This is directly reflective of the smaller impact these sub transmission lines have on the interconnected system relative to high voltage lines." In short, the available evidence demonstrates, that most transmission elements in the Western Interconnection operate at voltages above 200 kV, while lines operating in the range of 100-200 kV predominantly function as distribution lines, and, with a few exceptions, have little or no impact on the bulk transmission system. Using the 100-kV threshold, contained in the BES Definition recently approved by the NERC Board of Trustees is therefore likely to be substantially over-inclusive for facilities located

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| in the WECC. Using a 200-kV threshold with an inclusion mechanism to identify the minority of 115-kV facilities that operate as part of a the transmission system is, by contrast, likely to be much more efficient. |
| No |
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| Tacoma Power has no other comments to submit at this time. Thank you for consideration of our comments through this request for comments. |
| Individual |
| Jason Snodgrass |
| GTC |
| Yes |
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| Yes |
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| No |
| The SDT should limit any analysis for reliability benefits of “contiguous” with respect to source to BES, but not BES to load. BES to load represents Radial systems and should remain excluded from the BES without complication of "contiguous". |
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| No |
| The SDT should maintain focus of defining the BES only. |
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| No |
| An automatic interrupting device should not be a qualifier in confirming a bright line determination of a Radial system such that those facilities can be excluded. Radial systems are “facilities used in the local distribution of electric energy” and are also excluded in the core definition. Directing the use of an automatic interrupting device to qualify a Radial system conflicts with this core statement. |
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| Individual |
| Darryl Curtis |
| Oncor Electric Delivery Company LLC |
| No |
| The scope of the SAR is much too broad and should be more limited in scope. For example, the inclusion of Cranking Paths opens up the definition of BES to a very broad portion of the Bulk Electric System that would not provide corresponding reliability benefits. Furthermore, any inclusion of Cranking Paths should consider the impact only from those lines from a Black Start Resource to the most effective path to a generation resource. Oncor also takes the position that the 100 kV criteria is sufficient for Real and Reactive Resources. |

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| No |
| Oncor takes the position that the 100 kV criteria is sufficient for Real and Reactive Resources. Oncor also takes the position that the langusge in "I5" does not go far enough to exclude or include capacitor banks connected at the distribution level bus through a load bearing transformer. Oncor recommends further clarity be pursued with in “I5” or provide an exclusion of distribution level capacitors. |
| No |
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| No |
| In order to fully respond, Oncor would like further clarification of the intent and scope of a contiguous BES. |
| No |
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| No |
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| No |
| Oncor believes this effort is too broad and subjective. Oncor takes the position that the 100 kV criteria is generally sufficient. |
| Yes |
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| No |
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| No |
| Oncor takes the position that the inclusion of Cranking Paths opens up the definition of BES to a very broad portion of the Bulk Electric System that would not provide corresponding reliability benefits. Furthermore, any inclusion of Cranking Paths should consider the impact only from those lines from a Black Start Resource to the most effective path to the next generation resource. |
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| Yes |
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| Yes |
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| No |
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| No |
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| Group |
| Bonneville Power Administration |
| Chris Higgins |
| Yes |

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| Yes |
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| Yes |
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| Yes |
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| Yes |
| BPA believes that there needs to be a means to isolate the radial system from the BES during a fault on the radial system by means of an automatic fault interrupting device. Automatic Fault Interrupting Device should be a defined term. |
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| Yes |
| BPA believes that cranking paths and their assets are critical to the reliable operation of the Bulk Electric System and should always be included in the BES. |
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| No |
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| Yes |
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| No |
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| Yes |
| BPA believes that a system left connected in a network configuration, via use of a normally open switch for temporary network connection, without the protections afforded through the standards that apply to BES should be limited to less than 24 hours. BPA requests that the term “non-retail generation” in E3(a) should also be defined. BPA assumes that the SDT did define the term in the response to comments and requests that the definition be formalized. |
| No |
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| No |
| BPA does not know of any business practices that would be impacted by the BES definition. However, market operations, including scheduling, may have additional transmission networks evaluated due to the inclusion of BES into NERC standards such as the MOD standards. BPA is concerned that there may be the need to develop business practices if the exclusion process excluded so much of the BES that it becomes difficult to support the Transmission Service Provider operations and the Transmission Operator functions. |
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| Group |
| Southern Company |
| Antonio Grayson |
| No |
| Southern would like to provide the following comments: (A) The bulleted items in the project scope should be made more clear and we provide the following suggestions: “Determine if there is sufficient technical justification ... 1) to include equipment installed on the distribution system that "supports" the reliable operation of the BES; 2) to support including automatic interrupting devices in Exclusions |

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| E1 and E3; 3) to include Cranking Paths and Blackstart Resources; 4) to set 100kV as the minimum voltage level to be considered in the definition; and 5) to include local networks where power flows out of the network under certain conditions: (B) the meaning of the second bullet (“Determine if there is a technical justification to support the assumption that there is a reliability benefit of a contiguous BES”) is not clear. (C) we suggest removing the phrase "high quality and" from the next to last paragraph in the scope and (D) the Note related to this question stating the SDT does not intend to respond to all responses is inappropriate. All comments should be considered and an appropriate response should be provided. Part of the justification for the phase 2 SAR (as noted above) was that there were time constraints associated with Phase 1. Therefore, because there is time to further develop the definition of BES in this phase 2 process, all issues should be addressed in order to ensure that the technical support is fully developed. The SDT has identified several issues that are included in the scope of Phase 2 of the project that are associated with the technical aspects of the definition and require technical justification to drive a revision to the definition. Compelling technical justification is an essential component in moving any revision forward that addresses the technical nature of the BES definition. The SDT is seeking to identify existing technical justifications (i.e., completed studies, technical papers, etc.) and requests your assistance to properly identify resources available to the SDT which will facilitate the SDT’s work in prioritizing its efforts. Note: The SDT does not intend to respond to all responses associated with an entity’s knowledge of existing technical justification (i.e. analysis methodologies, completed studies, technical papers, etc.). The SDT is collecting potential resources that could assist in the development of compelling technical justification. |
| Yes |
| Southern agrees that the SDT should pursue the development of technically justified thresholds for Real and Reactive Power Resources, specifically for static, switchable capacitor banks at threshold levels vetted and determined with the benefit of the industry’s expertise. The SDT should clarify that static, switchable capacitor banks below such specific thresholds are not part of the BES. For example, in Southern’s experience, transmission capacitor banks are typically 18 to 30 MVAR units and dispersed geographically to help maintain voltages primarily in contingency situations. As such, these capacitor banks would not have a significant impact on the overall reliability of the BES. However, other industry stakeholders may have different experiences, and an appropriate MVAR threshold for static, switchable capacitor banks should be arrived at through industry input and technical review. Once the threshold has been determined, the SDT should clarify that static, switchable capacitor banks below such thresholds should be excluded from the BES definition. |
| No |
| The SDT should strive to establish thresholds for frequency impact ability and voltage impact ability when considering generating unit/plant sizes to be included in the BES. The impact on the reliability of the system due to the sudden loss of these generation resources should be studied. By today's standards, generating units that are 75 MVA or less make up a very small percent of the nation’s generation (MWH) and are expected to have much less of an impact on voltage and frequency disturbances than larger units. Therefore, Southern believes that these units (i.e., those that are 75 MVA or less) should be exempt from the definition of BES. Units of 75 MVA or less can be included in the BES through the exceptions process if system studies demonstrate, on a case-by-case basis, that a particular unit needs to be included based on its significant effect on voltage and frequency disturbances. An even greater threshold level may be deemed appropriate after sufficient industry input has been obtained, however Southern recommends a minimum threshold of higher than 75 MVA. |
| No |
| Southern is unsure what the SDT intends by the use of the phrase “contiguous BES” in this context. Southern agrees that there are reliability benefits associated with an interconnected BES. If the term “contiguous” in this context is intended to be synonymous with “interconnected”, Southern agrees that the pursuit of a technical justification to support such an assumption may be appropriate (to the extent one can technically justify an assumption). However, the SDT should clarify to commenters exactly what it intends by the use of the phrase “contiguous BES” in the context of this proceeding. |
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| No |
| Southern believes the SDT should first clarify distinctions between (a) equipment which “supports” |

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| the reliable operation of the BES and (b) equipment which “is necessary for” the reliable operation of the BES. This distinction would help industry understand if it is more efficient to develop technical justification or utilize the exceptions procedure as it already provides an individual entity with the flexibility to declare which equipment it believes should be included or excluded from the BES definition. |
| No |
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| No |
| It is unclear what specific devices the SDT intends to include in the term “automatic interrupting device”. To the extent the term “automatic interrupting device” would constitute gas-operated breakers – not relays – Southern would agree that such devices associated with Radial Systems (E1) and Local Networks (E3) should be included in Exclusions E1 and E3 (and thus excluded from the BES definition). However, the SDT should clarify the scope of devices encompassed within the term “automatic interrupting devices”. |
| No |
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| No |
| In its consideration of comments during Phase 1 of this project, the SDT acknowledged that Cranking Paths associated with Blackstart Resources often included distribution elements and decided to remove it from the draft inclusion. An entity can always use the ROP Exceptions procedure to request that certain Cranking Paths be included. Therefore, the SDT should not pursue this matter. Additionally, Inclusion I3 is limited to Blackstart Resources “identified in the Transmission Operator’s restoration plan”. This limitation may be implied in question six above. However, for purposes of clarification, the SDT should specify the entire phrase “Blackstart Resources identified in the Transmission Operator’s restoration plan” in all future references and discussions regarding this matter. |
| No |
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| No |
| A bright-line voltage level serves to provide consistent application of the BES Definition and therefore meets the Commission’s directives to the ERO. Accordingly, the ERO and Regional Entities would be better situated to distinguish those facilites which should be included in the Bulk Electric System from those which should be excluded. While the 100 kV voltage level has been debated in several forums, it is not clear that this level, as a starting point, would provide any more (or less) reliability improvements than an alternative level. The SDT could pursue justification for an alternative starting point while holding 100 kV as a minimum threshold. |
| No |
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| No |
| Southern agrees that the SDT should pursue technical justification for modifying Exclusion E3 to allow power flow out of the local network under certain conditions. There are occasional instances in some configurations where a contingency could cause power to flow into the BES from or through what are considered Local Networks. Disqualifying otherwise Local Networks from Exclusion E3 because of these contingencies would be overbroad. Therefore, the SDT should account for these contingencies by modifying Exclusion E3(b) to read as follows: “Under normal operating conditions, power flows only into the LN and the LN does not transfer energy originating outside the LN for delivery through the LN:”. In its filing to the Commission (Petition for Approval of a Revised Definition of the BES), NERC discussed Exclusion E1 (Radial Networks), the concept and usage of the “normal open switch”, and the concept of two sets of radial facilities that are normally unconnected (pages 19-21). NERC explained that the “normal open switch” between two normally unconnected radial facilities could occasionally be closed during certain “maintenance or outage circumstances.” NERC stated that “[t]he concept that two sets of radial facilities that are normally unconnected to each other should be subject to, and need to comply with, the Requirements of applicable Reliability Standards during the limited time periods when they are connected by the closing of the normally open switch in the maintenance-related or outage-related circumstances described above would be fundamentally |

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| impractical and unworkable (from both the entity's perspective and the ERO's perspective), and would misapprehend this very common, reliability-driven facilities configuration." Similarly with respect to Exclusion E3 (Local Networks), power only flows into the Local Networks under normal operating conditions. It is only during "limited time periods" during certain maintenance or outage circumstances that power would flow into the BES from or through the Local Networks. To disqualify such local networks from Exclusion E3, and thus to require them to comply with the Requirements of the applicable Reliability Standards because of the "limited time periods" that some power may flow out during "maintenance-related or outage-related circumstances" would also be "fundamentally impractical and unworkable … and would misapprehend this very common, reliability-driven facilities configuration." Southern does not agree, however, that the SDT should pursue technical justification to support a maximum allowable flow. Because the system topographies are too varied throughout the country to arrive at a uniform, maximum threshold, any attempt to establish one would be arbitrary. Therefore, as previously stated above, limiting the Exclusion E3(b)'s requirements to "normal operating conditions" – instead of a maximum power flow threshold – should produce a workable solution for the industry while still satisfying the Commission's directives. |
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| No |
| The disturbance creation thresholds established by the SDT (discussed in #9 above) should be at a fixed level, and regional variances can adjust the thresholds, if needed. |
| No |
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| Individual |
| Doug Hohlbaugh |
| FirstEnergy |
| Yes |
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| Yes |
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| No |
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| No |
| Equipment that supports the reliability of the BES need not be definitional to the BES. For example UFLS |
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| No |
| No, for similar reasons as above, we should not overly complicate the definition of the BES. Various items can be included in reliability standards required to support the BES, but they need not be |

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| definitional with the BES. |
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| Yes |
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| Yes |
| Yes, may be reasonable under certain contingency conditions. |
| No |
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| No |
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| No |
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| No |
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| No |
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| Individual |
| Michael Gammon |
| Kansas City Power & Light |
| Yes |
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| No other comments. |