# Rule 21 WG4, Issue 18 - Updated Questions

**XUtility Follow-up Questions**

For PG&E

- Follow up to my question 1 : Can PG&E share the" Anti-Islanding study with mixed DER types" study that is currently under NDA?
  *Awaiting permission.*

- Follow up to questions 5,7 and 8 and screen parameters: What methods other than a threshold approach has PG&E considered in identifying anti-islanding risk? Can a parameter that captures technology and cause be a better identifier (and likely capture risks more accurately rather than who came first)?
  *PG&E held a call with XUtility on 3/10 and awaits follow up.*

- Follow up to question 6: you mentioned that …"for the initial 40% the probability is on the low end.." What do you mean by low end (.01%, .5%, perceived vs actual….this is confusing as there is no single identified incident)?
  *It depends on the operational mode of the machine generator and type of inverter AI. In one case there are 0% RTO's > 2 secs at 25% and 4.5% RTO's > 2 seconds at 50% for another mode it was 0.2% ROT's > 2 seconds at 25% and 0.6% RTO's > 2seconds at 50%.*

**CALSSA Follow-up Questions**

12. SAND2018-8431 states "If the generation and load in a section of the power system are relatively well-balanced at the time of a grid disconnection, the islanded portion will naturally continue operating for a short time." Dr. Ropp's 2015 MIPSYCON paper (provided) states that this requires near perfect balance of both real and reactive power between the aggregate DER and aggregate load. Considering that most inverter based DER operates at .99pf, how much of your current electrical system is operating at a .99pf and therefore would fall into the category of having any potential to match reactive power with the DER load output?
*Having a .99 pf with matched real and reactive power would be required for a stable island, however the issue isn't related as much to a stable island but a run-on island in which the aggregate generation system takes over 2 seconds to terminate.*

Follow-up: CALSSA does not believe the information contained within the referenced literature supports PG&E's assertion. We can discuss this in person, but if you have a reference to the section of the relevant literature that supports this distinction between a stable self-sustaining island and a run-on lasting longer than two seconds with respect to reactive power matching we will study up ahead of time.
*Per the PG&E Interconnection handbook machine-based generation is set to operate at 0.9 leading and 0.9 lagging, while inverter base generation is operated at 0.85 leading and 0.85 lagging power factor for dynamic Var compensation.*

13. If it is not accounted for, how can it be added to a more enhanced review methodology?
*This may be difficult since var loading is changing and may not be well quantified, there may be an opportunity to use transmission line charging capacitance for transmission initiated islanding conditions, since this is a fixed and known quantity.*

Follow-up: CALSSA would like to hear PG&E's reaction to a method employed by Orange and Rockland

Utilities. An excerpt from their review methods are as follows. Note that the conclusion is "detailed islanding analysis" and not a recloser or DTT:
*Interested, would like to follow-up with Tim McDuffie on the details.*

*"Determine whether QPV + Qload is within 1% of the total aggregate capacitor rating within the island, or alternatively, use real and reactive power flow measurements or simulations at the point at which the island can form to determine whether the feeder power factor is ever higher than 0.99 (lag or lead) at that point for an extended period of time." If Yes to either evaluation, a detailed islanding analysis should be considered."*

An example of this analysis is as follows:

**Step-2 Analysis: Reactive Power Matching**

**Min Load** Note: Proposed PV projects is ON

| | Cap bank size ON tot (kvar) | Load flow result (kvar) | gross kVAR (QPV+Qload) | Total installed cap bank (kvar) | (Cap bank-load flow)/Cap bank |
|---|---|---|---|---|---|
| 89-2-13 | 600 | 565 | 1165 | 600 | -48.50% |
| Bank_189 SXF | 1800 | 2102 | 3902 | 4200 | 7.1% |

**IREC Follow-up Questions**

Screening

- Does PG&E have data on the types of inverters that are already installed on their system (for the purposes of identifying the types of anti-islanding techniques that they use for screening)?
  *PG&E provided an adequate response to this question in the meeting (essentially no, but they should track going forward), IREC would appreciate having it in writing though for record purposes.*
  *Presently inverter AI types are not tracked at PG&E, however based on recent Sandia study data it's clear the interaction between the various types of AI adversely affect run-on times during an unintended island. Knowing the different types of AI employed will aid in the ability to determine if the aggregate DER will terminate the island in a timely manner. Also there is no industry standard AI methodology, manufactures can develop additional AI methods that have not been identified and tested in aggregate with other AI methods. Current testing methodology per IEEE 1547.1 and UL 1741SA tests the DER as a standalone unit, and they do not specify the type of AI utilized to be identified. Going forward the aggregate effect of multiple AI types on UI run-on times may not be known.*
  *It's also clear from industry data that two types of AI are superior to the others, Group-1 and Group 2A as defined in SAND2018-8431. Inverters utilizing these AI types greatly reduce the chances of an extended ROT for aggregate DER consisting of mixed inverters and machine-based DER. Standardization of this type of AI would essentially eliminate the chance of an RTO greater*

*the 2 seconds. There may be unintended consequences in power quality and stability during a system transient that should be evaluated if this is the sole AI method utilized.*

Provide data on the number of circuits in your system that fail each of the different screens in the protection bulletin currently. *I sent PG&E clarifications on 2/25 and reiterated them in the call. They are clarified again below.*
*As I understand the bulletin there are multiple layers to the different screens you are applying, not just the 40% machine ratio.*

*Essentially I would like to know the number of circuits where the screens are under the thresholds for each of these screens in the Bulletin:.*

- *Section 1.2 sub 2(b) are failed.*
- *Section 1.3 (greater than 50% of minimum load) is failed.*
- *Section 1.3 sub 1(a) with subs(1) and (2)*
- *Section 1.3 sub 1(b)*

*Additional time is needed to provide a response.*

Costs and Schedule

- Please provide the minimum, maximum and mean times for the construction/installation of each recloser and/or DTT that has been required as a result of anti-islanding screening in the last 4 years (measured from the signing of the IA). *IREC would still like a response to this question, PG&E indicated they are still working on it and recommended that the timeline be measured from the "Special Facilities Agreement (SFA) invoice payment" or "final financial security posted" (depending on the project). We are fine with measuring the timeline as they proposed.*

*Additional time is needed to provide a response.*

Transparency

- Is information given to customers in the screening/study process that tells them (1) how PG&E concluded the project failed their screening (i.e. not just "failed screen" but the exact percentage of machines, non-certified inverters, etc.) and (2) how PG&E concluded that a recloser and/or DTT were required following the screening results. *PG&E responded partially to this question, but indicated that they "need to verify if the is information has been provided as part of the report." IREC would like to know if the screening tool is being used and what information it provides to the customer. Also, PG&E should verify if this "screen" is accurate (in terms of identifying whether a recloser or DTT is required) or if it is merely a guide.*
  *For the transmission portion of the screen, which includes the substation transformer aggregate, and transmission line section aggregate, percentages are provided for each portion as part of the screen. The screening tool is being used and is a pass/fail screen. The information used to populate the screening tool is obtained from SCADA data based on the calendar year or maximum yearly data is used and multiplied by 30% to obtain the minimum loading. Existing generator data is obtained via the PG&E SAP database.*

- Could the information necessary to determine whether the anti-islanding screen might be tripped (i.e. ratios of machine/non-certified generation) be provided in the ICA map (or, at a minimum, in the pre-application report)?
  *PG&E indicated that information regarding whether the anti-islanding screen might be tripped is not in the ICA map now and would require substantial effort for future implementation.*
  *This answers the question, but it does not explain why "substantial" effort would be required or what that means. Essentially, it would be helpful for PG&E to explain why it would be so difficult to do (the screens themselves appear to rely on data that should be readily available in their GIS).*

*The data is generally available in PG&E databases; however, automation and implementation of the screen would require additional effort, which are listed below:*

1. *Some machine generation or uncertified DG data might be missing from the database. Hence, additional effort is required to collect the essential information.*
2. *Data quality check and management is required.*
3. *Query of the data from database is required, which may involve identifying interconnectivity of various feeders and banks to compute aggregate load/gen.*
4. *Collaboration with PG&E third party vendor to integrate the screen to ICA software, which adds additional financial costs and technical effort.*
5. *Integrating the screen results to ICA map, which requires changes to data structure and its visual presentation.*
6. *Quality assurance and quality control activities.*