**Questions Submitted By: Mazyar Zeinali, XUtility**

*1)* What specific data can PG&E share to further illuminate issue 18?

*SANDIA2018-8431 Unintentional Islanding Detection Performance with Mixed DER Types. PG&E Anti-Islanding Study with mixed DER types" PG&E is under an NDA for this report.*

*2)* What data can other utilities share to further illuminate issue 18? *N/A*

*3)* Is PG&E's concern relative to a 40% threshold due to safety or equipment damage/failure? Please provide examples of safety and/or equipment issues that may occur.

*The 40% threshold is where machine-based generation may adversely affect the ability of the of aggregate generation to trip within 2 seconds.*

- *A sustained unintended island could result in a safety hazard if personnel are not aware that the DER is energizing a circuit.*
- *This could result in transient voltages and frequencies to customer equipment. Abnormal voltages on remote line sections may result in customer equipment damage.*
- *Reduced fault current capability in the islanded section leading to possible subsequent uncleared or delayed clearing faults. Additionally, unintended islands separate the normal grounding source from the islanding which could result in additional overvoltage conditions.*
- *Inverter based generation is a current limited source, as such the voltage sag during a fault is a method for inverter-based generation to detect and trip during fault conditions. High impedance faults may prevent the voltage reduction required for a timely trip of the inverter. This more likely for transmission line faults and substation transformer faults that do not generate much DER fault current.*
- *Automatic reclosing could result in an out of phase condition would causes high current and mechanical stress to machine-based equipment.*
- *For automatic reclosing equipped with voltage supervision, could result in lock-out of the recloser resulting in delayed restoration of customers.*

*4)* Do other utilities have any areas with mixed mechanical and PV generation? *N/A*

*5)* How did PG&E determine the 40% mix threshold for requiring mitigation*?*

*Initially from an AI study performed in late 2016, later corroborated in the PG&E AI study and later quantified in the SANDIA2018-8431 report for Group -1 AI.*

6) What is the incident probability for the 40% mix threshold and above?

*It depends on the location, generation mix, and the machine generation mode of operation. In general, for the initial 40% the probability is on the low end but gets up to 20% when the ratio is 75%.*

*7)* In its assessment, does PG&E consider mechanical generators the cause or PV installation as the cause of their concerns?

*In the case of existing machine-based generation installations the load and generation mix at the time of installation may have been acceptable, the follow-on PV installations with resulting loss of load have resulted in the need for mitigation. If the machine was installed later, it would be responsible for mitigation.*

8) Is PG&E requiring any mitigation from mechanical generation installations?

*Yes, if they meet the requirements referred to above.*

*9)* What research or data does PG&E use/point to establish their threshold/procedures?

*SANDIA2018-8431 Unintentional Islanding Detection Performance with Mixed DER Types. PG&E Anti-Islanding Study with mixed DER types. Initial study AI study performed in 2017 which raised the threshold from 10% to 40%.*

**<u>Questions Submitted By: Rebecca Davis, GPI</u>**

*1.* What risk does each IOU deem acceptable and unacceptable regarding islanding.

*Unintended Island is not allowed due to the reasons stated above.*

2. Describe the specific screen(s) you currently use to determine islanding risk and appropriate anti-islanding measures.

*Refer to TD 2306B DTT minimization and Rule 21 screens.*

*3.* For PG&E: what data would provide sufficient assurance for you to adopt a screening and mitigation process like SCE or SDG&E.

*Would like to review screens and DER protection processes including details of the other utilities systems. The system configuration can have a great effect on the screens and protection requirements.*

4. How should any changes to screening/mitigation process be codified?

*Possible screen for existing loading/certified inverter and machine generation for a given location/substation.*

*5.* Provide data on when, if ever, islanding occurred in practice and an inverter was not tripped.

*We are not aware of an unintended island; however, there is not good visibility to determine if one has occurred greater than 2 seconds. This also indicates the current screening process is successful.*

**Questions Submitted By: Brad Heavner, CALSSA**

For all IOUs:

1. Is the calculation of the ratio of generation to load done on a time of day and seasonal basis, or could load at 10 am in December be compared to generation at 1 pm in June?

*Calculation is based on 12-month minimum load data, solar is based on time of day in accordance with Rule 21 Screen N (G.2.a) Note-2. If non-solar will assume 24hr minimum.*

Will this change with implementation of ICA?

*No. The calculation of generation to load ratio is independent of ICA implementation.*

2. How many synchronous generators are installed on your distribution system?

*346 generating facilities, 759 MW total. This data includes synchronous generators that have been interconnected via Rule 21 and the Wholesale Distribution Tariff, PG&E-owned hydro facilities and Qualifying Facilities (QF) that converted to Interconnection Agreements in 2010 and later.*

3. How many SCADA reclosers are currently installed on your distribution system?

*In total we have 7388 reclosers.*

For PG&E only:

4. Bulletin TD-2306B-002 seems to suggest that all projects larger than 1 MW must install SCADA reclosers. Is that true in practice? Is that requirement in response to concerns that anti-islanding protections could fail?

*No, the 1MW requirement is to satisfy the 1 MW metering requirement. Due to the distributed nature of inverter based DER an individual AI failure should not adversely affect the AI capability of the aggregate DER resource.*

5. IEEE P1547, clause 8.1.2, "provides a new allowance for extending the clearing time to as much as 5 s upon mutual agreement between the DER operator and the Area EPS operator." Has this been incorporated into your anti-islanding review process?

*No*

If not, can this extended clearing time assessment be incorporated into new enhanced screening techniques? 5 second clearing time has not been discussed.

*If extended to 5 seconds there could be equipment issues related to GFOV on ungrounded High voltage winding substation transformers, notably lightning arrestors, transformer windings bushings and insulators that are not rated for the overvoltage condition. Unlike other utilities the typical PG&E substation transformer connection is wye-gnd on the HV side providing an effective ground, however there are fused transformers in the system that required the HV ground to be lifted, leading to GFOV susceptibility with high DER penetration. AI capability is considered a back-up for high impedance faults especially for those occurring on the transmission line or substation transformer winding which may not cause the expected voltage dip, a 2 second clearing time is close to the maximum allowed protective relay clearing time. There could also be power quality issues on interconnected customer equipment related to the 5 second time. Reclosing times for both transmission and distribution breakers would have to be reviewed for coordination with the 5 second time.*

6. It is CALSSA's understanding that there is a 10 second standard for utility lines that experience a fault. If a line is severed, it needs to be de-energized within 10 seconds. How does that standard relate to the 2 second standard?

*Maximum relay clearing times are 1.5 seconds for transmission (will be much shorter if there are stability issues). For the distribution system the goal is 1.5 to 2.0 seconds (may be faster for equipment I^2t limitations) or slower for distant fused laterals, 10 seconds is not a standard distribution clearing time.*

7. What portion of new synchronous generators required to shut down within 2 seconds of a de-energized line?

*They are all required to shutdown in ≤2. 0 seconds.*

What portion of existing synchronous generators shut down in 2 seconds?

*They are all required to shutdown in ≤2. 0 seconds. There may be transmission and distribution connected Hydro generation that do not meet the required (if known they will be mitigated by PG&E with DTT installed).*

Does PG&E ever require narrow set points for synchronous generators as a mitigation for run-on concerns?

*For distribution connected generation the Ca Rule 21 Table H settings are specified (non-ride through) this helps reduce the ride through requirement. For transmission generation the NERC PRC 24 voltage and frequency limits are applied and cannot be reduced.*

8. What portion of SCADA reclosers involve manual operation, with an operator seeing a anomaly and taking action.

*Presently 100%., looking to automate in the future for those associated with generation. It should be noted the majority of DTT installations were for transmission-initiated installations which trip the feeder breaker immediately reducing the island from the entire substation to a single feeder.*

9. How much “uncertified DG” is installed?

*Additional time is needed to provide a response.*

Does this refer to inverter-based generation with inverters that are not certified to UL 1741?

*Yes, however WTG generation should be the majority of uncertified DER’s interconnected. There are several large directly connected to the substation inverter based DER’s that have the anti-islanding disabled to allow ride-through capability (these have DTT installed).*

10. A SEL-651R relay is designed to manage islanding conditions. Is it being used and does it work in both the Tx and Dx islanding review scenarios?

*Additional time is needed to provide a response. Awaiting input from SEL.*

11. Over the last few years, has PG&E commissioned any of the published results?

*Please clarify the question. If it’s related to publishing AI results, the intent is to write a paper on this issue and other inverter-based issues when time permits.*

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.*

13. How is reactive power matching potential accounted for in your current anti-islanding review methodology?

*It is not.*

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.*

14. How many NEM projects have been under 1MW, required DTT, and had it installed as a “ratepayer

born" cost? What is the total quantity of ratepayer money that has been used to pay for DTT and what MW of renewable DER have they received in return?

*PG&E discussed this question with CALSSA and because PG&E doesn't have a direct way to pull this information, we have agreed to provide a ballpark figure this week for the number of projects within this subset that may have required DTT (using Interconnection Agreement cost data). Answering this question in full detail will require manual review of Interconnection Agreements and capital work order numbers, which at this time, CALSSA and PG&E have agreed isn't necessary.*

**<u>Questions Submitted By: Sky Stanfield, IREC</u>**

Screening

1) Provide data regarding the inverter types installed on each circuit.

*Need clarification of question. If it's referring to the Anti-islanding group types identified by the SANDIA screens the answer is PG&E is currently not asking for inverter types although with the SANDIA studies indicating differing anti-islanding types can increase ROT's this will change.*

2) Provide data on the number of circuits in your system that fail each of the different screens in the protection bulletin currently.

*We received additional information from IREC on this question. Additional time will be needed to provide a response.*

Costs and Schedule

3) 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).

*PG&E is working on ballpark figure for total projects requiring recloser or DTT (no exact data extractable at this time) for CALSSA question and that data can be used find the subset of projects for evaluation under this question as well. Collecting construction timeline data for these projects will require manual review of Interconnection Agreements to confirm that recloser or DTT was required. Once we understand the number of projects in this subset, we can provide an update on the length of time required to process this request.*

*Suggestion on start and end of construction timelines requested:*

*Instead of starting the timeframe at signing of the IA, PG&E suggests adjusting the start of the construction timeline evaluation to increase the accuracy of the timelines reported. Starting at the task "Special Facilities Agreement (SFA) invoice payment" or "final financial security posted" (depending on project type) will improve the data's accuracy because this would be the official start of the "construction" phase and eliminate the customer-driven portion of the time between IA execution and design start. For background: After the IA is signed, there is a customer-determined timeline for which to* *pay the SFA invoice or post financial security (no more than 180 CD after IA execution), so basing the start date would skew the data.*

Transparency

4) 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.

*A screening tool was developed in 2018 which visualized which part of the screen failed, the intent was to provide this data to the developer, need to verify if this information has been provided as part of the report. The screen was a straight pass/fail.*

5) 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)?

*This is not currently included in the ICA map and substantial effort is required for future implementation.*