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Unintentional Islanding Detection Performance with Mixed DER Types

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Abstract

Most inverters for use in distribution-connected distributed energy resource applications (distributed generation and energy storage) are tested and certified to detect and cease to energize unintentional islands on the electric grid. The requirements for the performance of islanding detection methods are specified in IEEE 1547-2018, and specified conditions for certification-type testing of islanding detection are defined in IEEE 1547.1. Such certification-type testing is designed to ensure a minimum level of confidence that these inverters will not island in field applications. However, individual inverter certification tests do not address interactions between dissimilar inverters or between inverter and synchronous machines that may occur in the field. This work investigates the performance of different inverter island detection methods for these two circumstances that are not addressed by the type testing: 1) combinations of different inverters using different types of islanding detection methods, and 2) combinations of inverters and synchronous generators. The analysis took into consideration voltage and frequency ride-through requirements as specified in IEEE 1547-2018, but did not consider grid support functionality such as voltage or frequency response. While the risk of islanding is low even in these cases, it is often difficult to deal with these scenarios in a simplified interconnection screening process. This type of analysis could provide a basis to establish a practical anti-islanding screening methodology for these complex scenarios, with the goal of reducing the number of required detailed studies. Eight generic Groups of islanding detection behavior are defined, and examples of each are used in the simulations. The results indicate that islanding detection methods lose effectiveness at significantly different rates as the composition of the distributed energy resources (DERs) varies, with some methods remaining highly effective over a wide range of conditions.

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EXECUTIVE SUMMARY

System operators require inverters used with distributed energy resources (DERs) be certified according to a standard that includes an anti-islanding test that is performed on an individual inverter, or a so-called "type test". That standardized type test is designed to test the inverter under a "realistic worst case" scenario to demonstrate that the islanding detection methods in the inverter under test will be effective under expected field conditions. While very useful, such a type test is imperfect and cannot anticipate all possible field conditions. In particular, there are two conditions that are nearly impossible to include in laboratory and certification testing because of the number of variables and resulting size of the required test matrix, and thus are not included in the standardized type tests:

- Combinations of inverters using different islanding detection methods; and
- Combinations of inverters and rotating generators, especially synchronous generators.

The purpose of the work reported in this document is to examine these two scenarios in more detail, comparing results from simulations using different inverter islanding detection methods and different mixes of inverter and synchronous machines. This analysis took into consideration voltage and frequency ride-through requirements as specified in Institute of Electrical and Electronics Engineers (IEEE) 1547-2018, but did not consider grid-support functions such as volt-var and frequency watt because these are being addressed in a separate report. Results are shown in terms of inverter run-on-times and examine the sensitivity of the run-on-time to DER mix with and without inverter ride-through activated. An important outcome of this work is the creation of a set of eight generic anti-islanding "groups" that can be used to describe the islanding detection methods used in a given inverter without requiring manufacturers to divulge excessive levels of confidential material. The results indicated the following.

1. Certain islanding detection methods do lose effectiveness when combined in the same island. The testing showed that certain combinations of islanding detection methods, when combined, exhibited larger non-detection zones (NDZs) and longer run-on times (ROTs).
2. The results depended strongly on the specific islanding detection methods studied. Two groups of methods (Groups 1 and 2A) performed much better than the others under all conditions tested. These two Groups performed well for mixtures of dissimilar inverters, for mixtures of inverters and rotating machines, and with or without ride-throughs.
3. The addition of synchronous generation does *in general* lead to increased ROTs and larger NDZs, although this is not true for *every* condition.
4. The inclusion of voltage and frequency ride-throughs increased the NDZ sizes and maximum ROTs, and thus increased the potential for unintended islanding to occur.

The primary motivation for this work was to serve as a first step toward the development of a practical anti-islanding screening methodology for these complex scenarios, with the ultimate goal of ensuring that detailed studies are required only in the few cases in which they are truly needed. These results are intended to guide further evaluation steps and technical decisions on course to update Sandia's recommended evaluation method described in SAND2012-1365, that can be applied in specific interconnection cases. This follow up work is currently underway.

NOMENCLATURE

Abbreviation	Definition
Abbreviation	Definition
AI	Anti-Islanding
CLIM	Classical Linear Instability Method
DER	Distributed Energy Resource
GSU	Generator Step-Up (transformer)
IEEE	Institute of Electrical and Electronics Engineers
NDZ	Non-Detection Zone
POI	Point Of Interconnection
RoCoF	Rate of Change of Frequency (i.e., df/dt)
ROT	Run-On Time
RT	Ride-Through
SFS	Sandia Frequency Shift

1. INTRODUCTION

Islanding in distribution systems is a condition in which some portion of a distribution circuit is energized solely by distributed energy resources (DERs) while that portion of the distribution circuit is disconnected from the rest of the grid. Intentional islanding in which the island is planned, properly protected, controlled, and coordinated with the area power system can improve reliability of service to end users, and thus has the potential to be highly beneficial. However, unintentional islands do not have these properties, and if sustained they can pose risks to equipment or personnel.

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. Applicable codes and standards such as Institute of Electrical and Electronics Engineers (IEEE) 1547 [1,2] require that DERs detect the formation of an unintentional island and cease to energize that island within 2 seconds. Longer duration unintended islanding are considered to be problematic.

For inverters used with DERs, methods for detecting unintentional islands are well-described elsewhere [3-6]. Most utilities require that inverters for distribution connection of DERs be listed to a standard such as UL-1741, which is harmonized with IEEE 1547 and includes a test specifically designed to assess the effectiveness of the islanding detection method used. Inverters that have been tested and certified under UL 1741 or a similar standard have undergone extensive abnormal and loss of utility detection type testing and have been certified to meet the anti-islanding requirements, while providing EPS support functionalities. However, obviously the test cannot test *all* real-world conditions, so a number of situations that do occur in the real world are not explicitly probed by the test. Two situations not covered by typical anti-islanding tests [7] and that are increasing in commonality are:

- Combinations of inverters using different islanding detection methods; and
- Combinations of inverters and rotating generators, especially synchronous generators.

The purpose of the work reported here was to study via simulation the effectiveness of various types of islanding detection methods in these two situations. Part of the motivation for pursuing this work was to serve as the basis for a new screening process that ultimately would replace the one described in [7]. That screening process was simple, had the advantage of being almost independent of the type of anti-islanding being used in the inverters, and has been widely used by utilities. However, the underlying philosophy used to derive that screening process will not give satisfactory results when voltage and frequency ride-throughs are used as required in IEEE 1547-2018 [2]. Thus, the authors have taken a new approach in this work: there is higher reliance on the IEEE 1547.1 type test for anti-islanding, and the screening tools then have to take into account cases that are not explicitly covered by the type test. Hence, the work reported here, focusing on the two situations mentioned above, is intended to lay the first foundations for a new screening process in which the inverter anti-islanding type is characterized generically, and then the properties of each anti-islanding category, or group, are determined and used for screening.

2. PROCEDURE

2.1. Categorization of islanding detection methods

For this work, anti-islanding methods used in inverters were separated into eight Groups, defined as follows.

- AI Group 1: Inverters in this group utilize an output perturbation in positive-sequence fundamental frequency or phase that is specifically for the purpose of island detection, and that grows continuously in magnitude as frequency error increases in a direction that increases the frequency error (i.e., positive feedback on frequency error), up to the frequency trip limits, and includes no dead zone. In other words, Group 1 inverters use positive feedback on frequency or phase to create instability when the island forms. The output perturbation may be pulsed or continuous, but the key is the positive feedback; the magnitude of the perturbation must continuously increase with increasing frequency error as long as the inverter is within the frequency trip bands.

- AI Group 2A: These inverters are similar to Group 1 in that the inverter produces a pulsed or non-pulsed output perturbation in positive-sequence fundamental frequency or phase that is specifically for island detection and grows with frequency in a direction that increases the frequency error (i.e., positive feedback on frequency error), but not continuously to the trip bands. Inverters in this Group may have a stepped or otherwise discontinuous function of frequency, or a saturation limit that is reached prior to the frequency trip thresholds. However, because the impact of a dead zone (hysteresis about 60 Hz in which the anti-islanding perturbation is not produced) is a special case, *inverters with a dead zone about 60 Hz are specifically excluded from Group 2A.*

- AI Group 2B: This Group has any or all of the properties of Group 2A, but with a dead zone about 60 Hz in which the active anti-islanding does not act.

- AI Group 2C: This group has any or all of the properties of either Group 1 or Group 2A, except that the positive feedback on frequency error is *unidirectional*; that is, the positive feedback is in the same direction regardless of the algebraic sign of the frequency error.

- AI Group 3: This group produces an output perturbation in positive-sequence fundamental frequency or phase, the magnitude of which does NOT grow with increasing frequency error or is NOT specifically designed for island detection.

- AI Group 4: Inverters in this group produce an output perturbation at a harmonic (not fundamental) frequency that is specifically for the purpose of detecting an island. Typically these are independent of frequency error.

- AI Group 5: Inverters in this group rely on passive methods only (such as RoCoF or vector shift) or advanced signal processing of voltage or current measurements to detect island formation. (A method that drives the frequency of an island to the frequency trip limits and then relies on the passive frequency trip does NOT fall into Group 5.)

- AI Group 6: Inverters in this group manipulate the negative sequence current for the purpose of island detection, and apply positive feedback to that negative-sequence perturbation. This may be achieved by several means, including altering individual phase current magnitudes or dithering the phase angle separation between the three output current phases.

2.2. Simulation models

2.2.1. Test circuit

All DERs were tested in the test circuit shown in Figure 1.

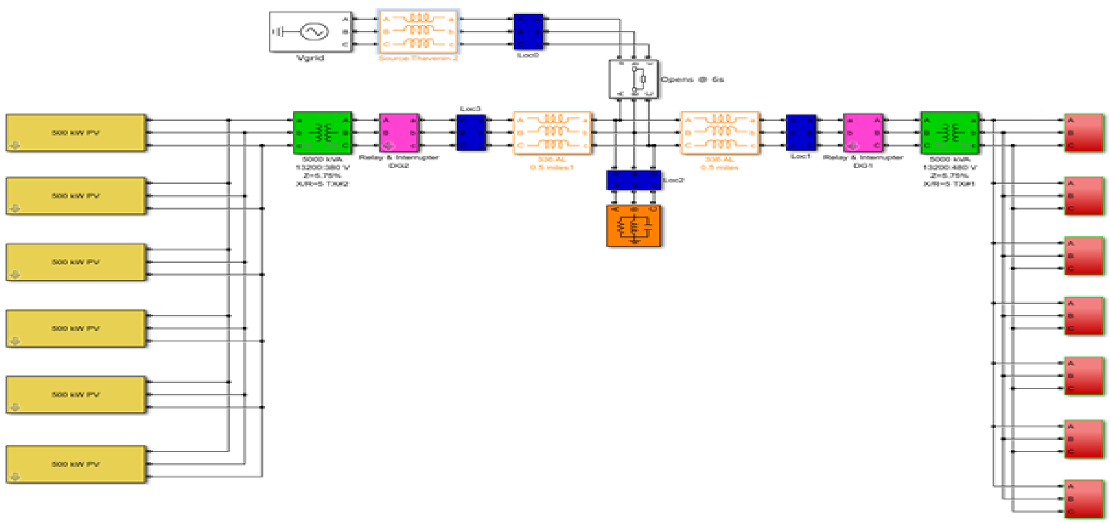

Figure 1. Test circuit used in this work.

The yellow and red blocks are individual DER units. The 13.2 kV utility source connects to the center of the circuit through its source impedance. The load is lumped near the center of the circuit in a manner that mimics the IEEE 1547.1 anti-islanding test [12], and is represented by the orange block near the middle of the figure. Each DER plant has its own generator step-up (GSU) transformer (the two green blocks), and between each DER plant and the utility source is a circuit series impedance equivalent to one mile of 336 AAL conductor. In this way, both DER plants see the same source impedance, and their impacts on their respective point of interconnection (POI) voltages are relatively independent of one another[1]. To simplify dealing with different unit sizes, no impedance is included between the individual units themselves; only the circuit impedance seen by the entire plant is included. The dark blue blocks are measurement blocks.

[1] There is some dependency of one POI voltage on the other because there is also a source impedance just to the right of the voltage source that is seen by both plants, but that common source impedance is by far the smallest of the various source impedance elements and thus its effect is small.

2.2.2. *Inverter models*

For each AI family listed above, an example of a detailed manufacturer-specific three-phase inverter model utilizing that AI Group was selected. The inverters ranged in size from 33 to 500 kW. Switch-averaged models were used, with DC and AC side filters explicitly represented. An I-V curve representation of a PV array is used as the DC source. Each example's PLL and DC voltage and AC current regulators are represented in detail. Maximum power point tracking was not included because it can generally be assumed that the irradiance will not change appreciably during the time period of an anti-islanding test and thus the DC references will remain constant.

Each inverter contains a typical set of over/undervoltage and over/underfrequency relays, with the settings shown in Table 1. Two sets of values were used for these settings, one with and one without ride-throughs (RTs). The case without RTs corresponds to the values listed in IEEE 1547-2003 [1]. The case with RTs comes from IEEE 1547-2018 [2].

Table 1. Protective relay settings used in inverter models

Cases without ride-throughs (RTs)		
Element	Pickup	Delay
UNDERVOLTAGE (27)	0.5 pu	0.16 sec
UNDERVOLTAGE (27)	0.88 pu	2 sec
OVERVOLTAGE (59)	1.1 pu	1 sec
OVERVOLTAGE (59)	1.2 pu	0.16 sec
UNDERFREQUENCY (81U)	59.3 Hz	0.16 sec
OVERFREQUENCY (81O)	60.5 Hz	0.16 sec
Cases with ride-throughs (RTs)		
UNDERVOLTAGE (27)	0.5 pu	2 sec
UNDERVOLTAGE (27)	0.88 pu	21 sec
OVERVOLTAGE (59)	1.1 pu	13 sec
OVERVOLTAGE (59)	1.2 pu	0.16 sec
UNDERFREQUENCY (81U)	56.5 Hz	0.16 sec
UNDERFREQUENCY (81U)	58.5 Hz	300 sec
OVERFREQUENCY (81O)	61.0 Hz	300 sec
OVERFREQUENCY (81O)	62.0 Hz	0.16 sec

2.2.3. *Synchronous generator models*

The synchronous generators tested in this work used MATLAB's built-in sixth-order model of the synchronous machine, with parameters selected from manufacturer datasheets to match the size of generator desired. The prime mover model is highly simplified and utilizes two first-order lag functions, one for the throttle and one for the engine. The speed controller model is based on an internally-developed model that represents behaviors of three of the most popular speed controllers in use today, and has been vetted against manufacturer data and a limited set of laboratory tests. Similarly, the exciter/AVR model used here is based on an in-house model that has been validated against three commercially-available units and found to represent their behaviors well.

For all tests reported here, the synchronous generators were operated in constant P-Q control mode, with the Q command set to zero. This is the most common control method encountered in the field.

2.3. Test matrix

Simulations were conducted varying the following parameters:

- Inverter vs. inverter cases: in these cases, the yellow and red blocks in Figure 1 are all inverters, with each set of inverters using a different anti-islanding method selected from the six families described earlier. The relative proportion of inverters from each category in terms of AC nameplate rating was swept in each case, keeping the total amount of generation constant. For each combination and proportion of inverters, the real and reactive load were swept over fixed ranges, resulting in 850 simulations for each inverter combination. The inverter types tested were:
    - AI Group 1: "Classic" Sandia Frequency Shift (SFS) [8].
    - AI Group 2A: "Classic" SFS but with saturation limits.
    - AI Group 2B: SFS implementation similar to that in [9] in which the frequency-dependent output is pulsed, not continuous (sometimes called "impedance detection with positive feedback", or "quasi-SFS"), and includes a small dead zone around 60 Hz. This one does not have saturation limits.
    - AI Group 2C: This group was not represented in this work, because Group 2C was added to the list of groups after this simulation work was completed, in response to industry feedback. Group 2C will be included in future work.
    - AI Group 3: Impedance detection based on production of a var pulse [10]. The pulse is specifically intended for islanding detection, but its magnitude does not grow with frequency error.
    - AI Group 4: AI Group 4 was not represented in this work. This was done for two reasons. First, proper study of Group 4 would require a test circuit that properly represents the circuit's harmonic properties, and the test circuit used here was not configured in that way so the results could be misleading. Second, the model contains no harmonic-producing sources other than the

inverters and no other system nonlinearities, and thus does not properly represent the situation that would be most challenging for AI Group 4. Thus, full analysis of Group 4 remains as a future-work item.

  - AI Group 5: RoCoF with settings of 2 Hz/s averaged over a window of 0.1 s (i.e., a 0.2 Hz average df/dt over a 0.1 s window).
  - AI Group 6: The Group 6 example applies a negative sequence disturbance [11] by altering the (normally 120º) phase angles between phases B and C that grows larger as frequency error increases. Island detection is based on either the phase angle deviation or any of the line-line voltages leaving allowed ranges (i.e., the negative sequence voltage).

- Inverter vs. synchronous machine cases: in these cases, the yellow blocks are inverters using one of the six anti-islanding methods, and the red blocks were synchronous generators equipped with only passive relays using the settings in Table 1. Again, the relative proportion of inverters and synchronous generators was varied, and the load P and Q were swept over fixed ranges to locate the worst-case run-on times. In the inverter vs. machine cases, the inverters tested were as follows:
  - Two different Group 1 examples, labeled “1-1” and “1-2” here. Example 1-1 is a straightforward implementation of SFS, and Example 1-2 uses the “Classical Linear Instability Method” (CLIM) [12] to achieve positive feedback on phase.
  - One example of an inverter that is most closely represented by Group 2B, but is not an exact fit. Here this inverter is denoted “2B-1”. This inverter does not have a dead zone, but its anti-islanding gain is held to a very low constant value until a certain frequency error is achieved. Thus, although there is not strictly a dead zone in the frequency “push”, there *is* a dead zone in the positive feedback. This inverter also increases its gain on the basis of time, and not only frequency error (i.e., if the frequency error remains above a certain level for a certain amount of time, the inverter will increase the positive feedback gain).
  - Another Group 2B inverter, called “2B-2”, that does fit strictly within the 2B definition: it is essentially classical continuous SFS but with a dead zone about 60 Hz.
  - One Group 3 inverter.
  - One Group 6 inverter.

In each simulation, the run-on time (ROT) of the DERs was recorded, and an ROT of greater than 2 was deemed a failure of the test.

Each data point in the results represents 850 separate simulations. It would obviously be desirable to increase the resolution and decrease the discretization of the simulation results by looking at more fractional mixture values, but the results here were the best that could be done within the available resources. Some discretization of the results is inevitable because real-world inverter and generator examples with fixed nameplate ratings were used, and to ensure comparable data sets all were operated at full output power.

3. RESULTS

3.1. Cases without Ride-Throughs

3.1.1. Mixtures of dissimilar inverters, without ride throughs

The results obtained for mixtures of inverters are summarized in the Tables and Figures below, for cases with the relays set to the IEEE 1547-2003 values (no RTs).

- Table 2 shows the number of loading cases for each combination and proportionality that led to an ROT exceeding 2 s.
- Table 3 shows the same data as

- Table 2, except expressed as a fraction of the 850 loading scenarios in which ROTs exceeded 2 s.
- Table 4 shows the maximum ROT seen for each combination, over all 850 loading scenarios tested for each DER combination.
- Figure 2 shows the number of loading cases leading to ROTs > 2 s for Group 1 inverters.
- Figure 3 shows the number of loading cases leading to ROTs > 2 s for Group 2A inverters.
- Figure 4 shows the number of loading cases leading to ROTs > 2 s for Group 2B inverters.
- Figure 5 shows the number of loading cases leading to ROTs > 2 s for Group 3 inverters.
- Figure 6 shows the number of loading cases leading to ROTs > 2 s for Group 5 inverters.
- Figure 7 shows the number of loading cases leading to ROTs > 2 s for Group 6 inverters.

On the key question of whether combining different islanding detection methods reduces islanding detection effectiveness, these data suggest that the answer is generally "yes", but with quite a few caveats and subtleties. Some considerations to bear in mind:

- The curvature of the traces gives key information regarding the interaction between the two inverter groups under test.
  - If there is a maximum in NDZ size in the middle of the distribution (i.e., the curve generally arches upwards), then this indicates that the two islanding detection methods are interacting in a way that reduces their combined effectiveness. In other words, there will be a certain NDZ size at 100% of one inverter and another at 100% of the other inverter, and if the NDZ size reaches a maximum between these two extremes, this indicates that the mixture led to reduced islanding detection effectiveness. The location of the maximum would not always be at the 50%-50% split point; if the two islanding detection methods have significantly different effectiveness overall (that is, if one method has a considerably larger NDZ at 100% of that method than at 100% of the other one), then the location of the maximum NDZ size should skew closer to the end of the distribution corresponding to 100% of the weaker method.
  - If the curve appears "quasi-exponential" in the sense that it is essentially flat but then rises sharply close to 0% or 100%, then this indicates that one method is much stronger than the other one and is dominating the response of the island.
  - It is also possible that certain methods, when mixed, could perform better than

either method alone. In this case, what would be expected is a *minimum* between the endpoints in which the curve generally arches downwards.

    - If there were essentially no interaction between the inverters, what would be expected would be a straight line between the 0% and 100% endpoints.

- For each plot in this section, all traces would be expected to converge to a single point at the right side of the plot (i.e., at 100% of the method represented on the x-axis).

- Because of the highly dynamic nature of the nonlinear system being simulated, and the fact that ROTs can be extremely sensitive to small variations in P and Q match (particularly Q) within the island, the discretization of these simulations in some cases leads to non-smooth trends and outliers.

With those considerations in mind, looking at the figures and tables, the following conclusions can be drawn.

1. For the no-RT case, no combination of islanding detection methods led to an especially large NDZ. In the worst cases, just over 3% of the 850 points tested led to an ROT over 2 s. However, for many of the combinations, the longest ROTs were rather long, up to 10 s, which is the longest time these simulations could detect.

2. The AI Group 1 inverters were effective at detecting islands even when relatively little of the total DG was Group 1. As long as 25% or more of the inverters were Group 1, no loading conditions led to an ROT exceeding 2 s. Even if only 10% of the DER were Group 1, in the worst case only 0.35% of the 850 cases tested led to ROTs over 2 s.

3. Group 2A was as effective as Group 1—in fact, there were fewer extended run-ons overall for Group 2A than for Group 1. This is attributed to the fact that the example Group 2A inverter had a slightly higher positive-feedback gain than the Group 1 example. In any case, the results suggest that the introduction of the saturation limits did not significantly reduce the island detection effectiveness of the SFS.

4. The effectiveness of Groups 2B, 3 and 5 were similar to one another, and all were less effective than Groups 1 or 2A. ROTs exceeding 2 s were observed even when 75% of the DER was from one of these Groups. For Group 2B, the reduction in effectiveness was primarily due to the presence of the dead zone.

5. The results in Table 2 and Table 3 for Group 6 inverters are a bit misleading: several ROTs over 2 s are seen, but these are the maximum ROTs of the *island*, and in most cases those extended ROTs were actually observed in the non-Group-6 inverter in the test. For example, when at least 75% of Group 6 was paired with Groups 3 or 5, the Group 6 inverters tripped in less than 2 s in all cases but the Group 3 and 5 inverters each had three ROTs exceeding 2 s.

6. In Table 4, a maximum ROT of 10 s indicates an indefinite ROT and a stable island, bearing in mind that the load is constant in these simulations. In most of the cases in which any failures are detected, the resulting island was stable, although there are a few exceptions—for example, for 25% Group 3 vs. Group 6, out of the three ROTs exceeding 2 s the longest one lasted just 2.3 s. Although this case technically did violate the 2 s

limit, clearly this case would be of less concern, or lower risk, than a stable, 10-s case.

7. Figure 2 and Figure 3 fall into the "quasi-exponential category" that indicates that the Group 1 and 2A inverters strongly dominate the island. The ROT plots show mostly zeros, only rising when 10% of the Group on the x-axis remains in the island.
8. Figure 4 through Figure 7 generally fall into the "upward-arching" category that supports the notion that the islanding detection effectiveness of the combination of methods is reduced from that of either method operating in isolation, but the trend is not absolute. For example, Figure 4 shows the ROTs as a function of the fraction of DER comprised of AI Group 2B inverters. The combination of Groups 2B and 6 has a clear maximum for a 50-50 mix of the two inverter types, but it also shows a local minimum for 90% Group 2B. The combination of Groups 2B and 5 shows that the NDZ size does increase as the Group 2B fraction is decreased, but only to a point; instead of decreasing again, the number of ROTs > 2 s remains constant when there is less than 50% of Group 2B inverters in the island, and finally increases again for 10% Group 2B. The combination of Groups 2B and 3 *might* follow this trend, but it is difficult to tell because the trace is "noisy", which may indicate a heightened sensitivity to the P-Q balance in the island. Similar comments apply to Figure 5, Figure 6, and Figure 7.

Table 2. Number of loading scenarios (out of 850) in which run-on times exceeded 2 s: inverter vs. inverter cases, no RTs

Vs	Amount of Class 1 DG							Vs	Amount of Class 3 DG						
	0%	10%	25%	50%	75%	90%	100%		0%	10%	25%	50%	75%	90%	100%
2A	0	0	0	0	0	0	0	1	0	0	0	0	0	3	21
2B	10	1	0	0	0	0	0	2A	0	0	0	0	0	3	21
3	21	3	0	0	0	0	0	2B	10	4	14	7	20	26	21
5	20	3	0	0	0	0	0	5	20	23	23	26	24	25	21
6	0	0	0	0	0	0	0	6	0	0	3	18	25	25	21
Vs	Amount of Class 2A DG							Vs	Amount of Class 5 DG						
	0%	10%	25%	50%	75%	90%	100%		0%	10%	25%	50%	75%	90%	100%
1	0	0	0	0	0	0	0	1	0	0	0	0	0	3	20
2B	10	0	0	0	0	0	0	2A	0	0	0	0	0	3	20
3	21	3	0	0	0	0	0	2B	10	7	12	15	15	15	20
5	20	3	0	0	0	0	0	3	21	25	24	26	23	23	20
6	0	0	0	0	0	0	0	6	0	0	3	24	20	24	20
Vs	Amount of Class 2B DG							Vs	Amount of Class 6 DG						
	0%	10%	25%	50%	75%	90%	100%		0%	10%	25%	50%	75%	90%	100%
1	0	0	0	0	0	1	10	1	0	0	0	0	0	0	0
2A	0	0	0	0	0	0	10	2A	0	0	0	0	0	0	0
3	21	26	20	7	13	4	10	2B	10	6	10	20	0	0	0
5	20	15	15	15	11	7	10	3	21	25	23	17	0	0	0
6	0	0	0	21	10	6	10	5	20	23	20	22	0	0	0

Table 3. Table 2 information, expressed as the percent of total cases in which 2 s run-ons were observed: inverter vs inverter, no RTs

Vs	Amount of Class 1						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
2A	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2B	1.2	0.1	0.0	0.0	0.0	0.0	0.0
3.0	2.5	0.4	0.0	0.0	0.0	0.0	0.0
5.0	2.4	0.4	0.0	0.0	0.0	0.0	0.0
6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Vs	Amount of Class 3						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
1.0	0.0	0.0	0.0	0.0	0.0	0.4	2.5
2A	0.0	0.0	0.0	0.0	0.0	0.4	2.5
2B	1.2	0.5	1.6	0.8	2.4	3.1	2.5
5.0	2.4	2.7	2.7	3.1	2.8	2.9	2.5
6.0	0.0	0.0	0.4	2.1	2.9	2.9	2.5

Vs	Amount of Class 2A						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2B	1.2	0.0	0.0	0.0	0.0	0.0	0.0
3.0	2.5	0.4	0.0	0.0	0.0	0.0	0.0
5.0	2.4	0.4	0.0	0.0	0.0	0.0	0.0
6.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0

Vs	Amount of Class 5						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
1.0	0.0	0.0	0.0	0.0	0.0	0.4	2.4
2A	0.0	0.0	0.0	0.0	0.0	0.4	2.4
2B	1.2	0.8	1.4	1.8	1.8	1.8	2.4
3.0	2.5	2.9	2.8	3.1	2.7	2.7	2.4
6.0	0.0	0.0	0.4	2.8	2.4	2.8	2.4

Vs	Amount of Class 2B						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
1.0	0.0	0.0	0.0	0.0	0.0	0.1	1.2
2A	0.0	0.0	0.0	0.0	0.0	0.0	1.2
3.0	2.5	3.1	2.4	0.8	1.5	0.5	1.2
5.0	2.4	1.8	1.8	1.8	1.3	0.8	1.2
6.0	0.0	0.0	0.0	2.5	1.2	0.7	1.2

Vs	Amount of Class 6						
	0.0	0.1	0.3	0.5	0.8	0.9	1.0
1.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2A	0.0	0.0	0.0	0.0	0.0	0.0	0.0
2B	1.2	0.7	1.2	2.4	0.0	0.0	0.0
3.0	2.5	2.9	2.7	2.0	0.0	0.0	0.0
5.0	2.4	2.7	2.4	2.6	0.0	0.0	0.0

Table 4. Maximum ROTs (in seconds) seen for all cases in inverter-vs-inverter scenarios, no RTs

Vs	Amount of Class 1						
	0%	10%	25%	50%	75%	90%	100%
2A	0.29	0.28	0.28	0.26	0.3	0.36	0.38
2B	10	10	0.96	0.48	0.47	0.37	0.38
3	10	10	1.79	0.57	0.41	0.34	0.38
5	10	10	1.28	0.6	0.37	0.34	0.38
6	0.28	0.42	0.53	0.5	0.5	0.35	0.38

Vs	Amount of Class 3 DG						
	10%	10%	25%	50%	75%	90%	100%
1	0.4	0.3	0.4	0.6	1.8	10	10
2A	0.3	0.3	0.3	0.4	1.3	10	10
2B	10	10	10	10	10	10	10
5	10	10	10	10	10	10	10
6	0.3	0.5	2.3	10	10	10	10

Vs	Amount of Class 2A						
	0%	10%	25%	50%	75%	90%	100%
1	0.38	0.36	0.31	0.27	0.28	0.29	0.29
2B	10	1.03	0.49	0.35	0.34	0.28	0.29
3	10	10	1.34	0.35	0.29	0.28	0.29
5	10	6.03	0.89	0.38	0.29	0.28	0.29
6	0.28	0.44	0.71	0.33	0.33	0.28	0.29

Vs	Amount of Class 5 DG						
	0%	10%	25%	50%	75%	90%	100%
1	0.4	0.3	0.4	0.6	1.3	10	10
2A	0.3	0.3	0.3	0.4	0.9	6	10
2B	10	10	10	10	10	10	10
3	10	10	10	10	10	10	10
6	0.3	0.5	2.3	10	10	10	10

Vs	Amount of Class 2B						
	0%	10%	25%	50%	75%	90%	100%
1	0.38	0.37	0.47	0.48	0.96	10	10
2A	0.29	0.29	0.35	0.36	0.5	1.02	10
3	10	10	10	10	10	10	10
5	10	10	10	10	10	10	10
6	0.28	10	10	10	10	10	10

Vs	Amount of Class 6 DG						
	0%	10%	25%	50%	75%	90%	100%
1	0.4	0.4	0.5	0.5	0.5	0.3	0.28
2A	0.3	0.3	0.3	0.3	0.5	0.3	0.28
2B	10	10	10	10	0.6	0.3	0.28
3	10	10	10	10	0.6	0.3	0.28
5	10	10	10	10	0.6	0.3	0.28

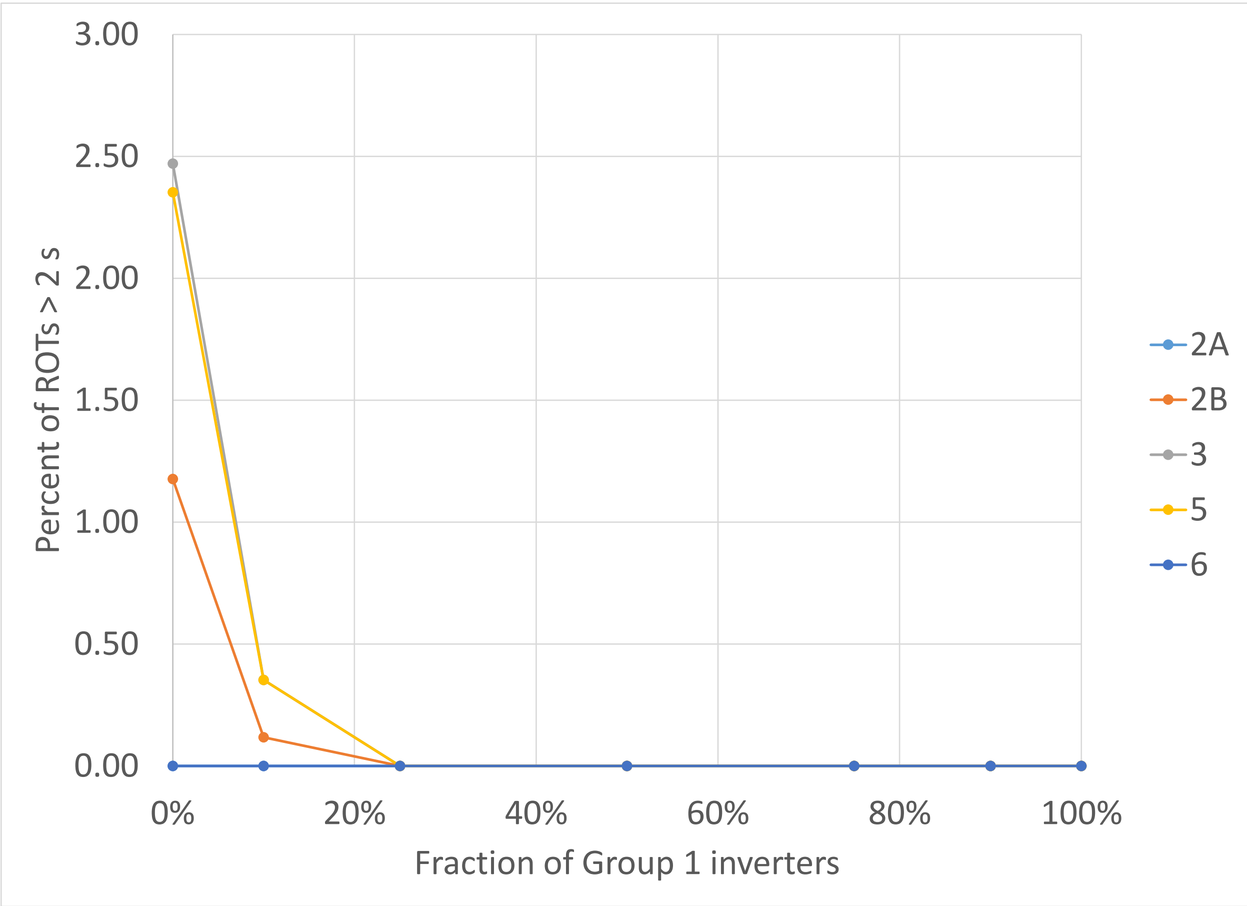

Figure 2. Plot of the number of ROTs greater than 2 s as the number of AI Group 1 inverters is varied, without RTs. The chart legend shows which type of inverter Group 1 is mixed with.

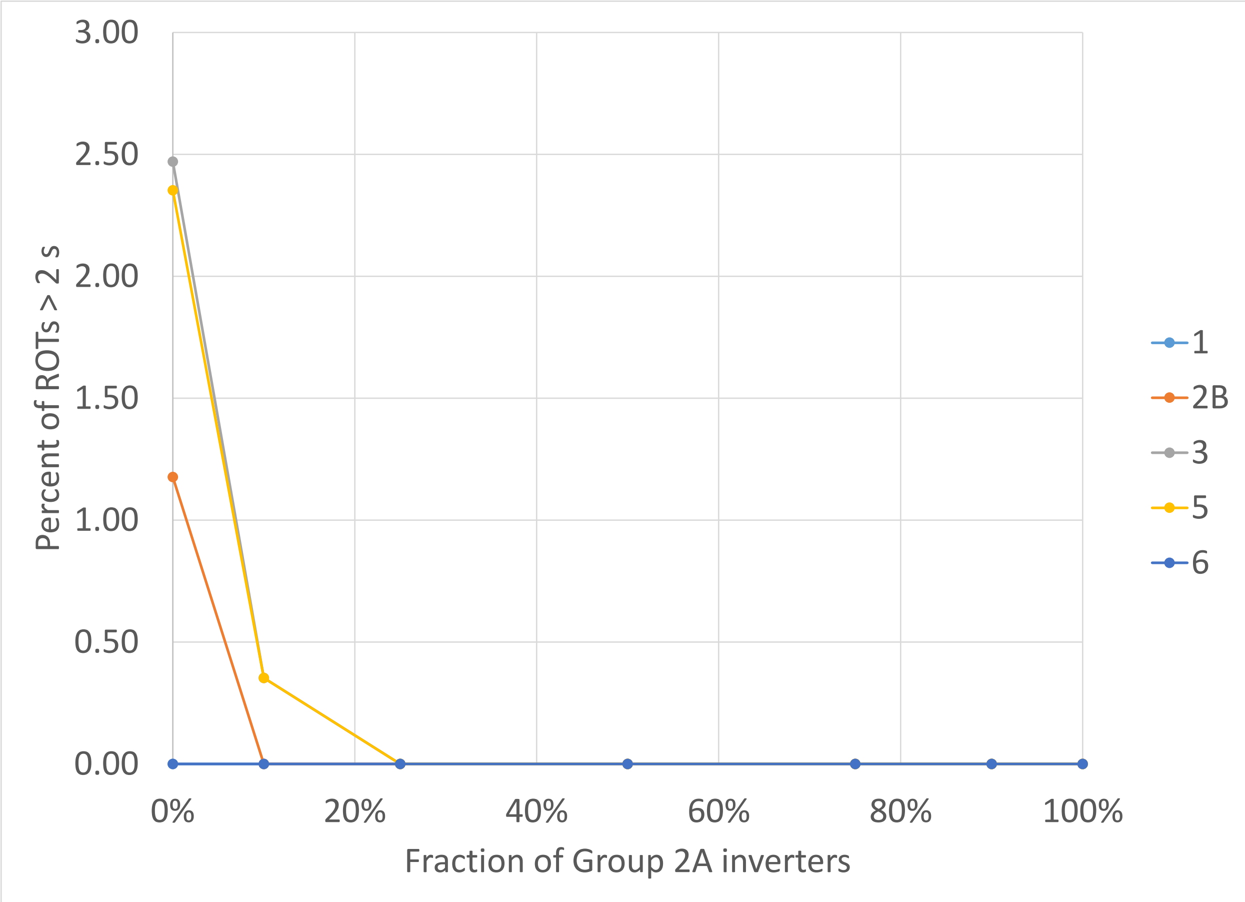

Figure 3. Plot of the number of ROTs greater than 2 s as the number of AI Group 2A inverters is varied, without RTs. The chart legend shows which type of inverter Group 2A is mixed with.

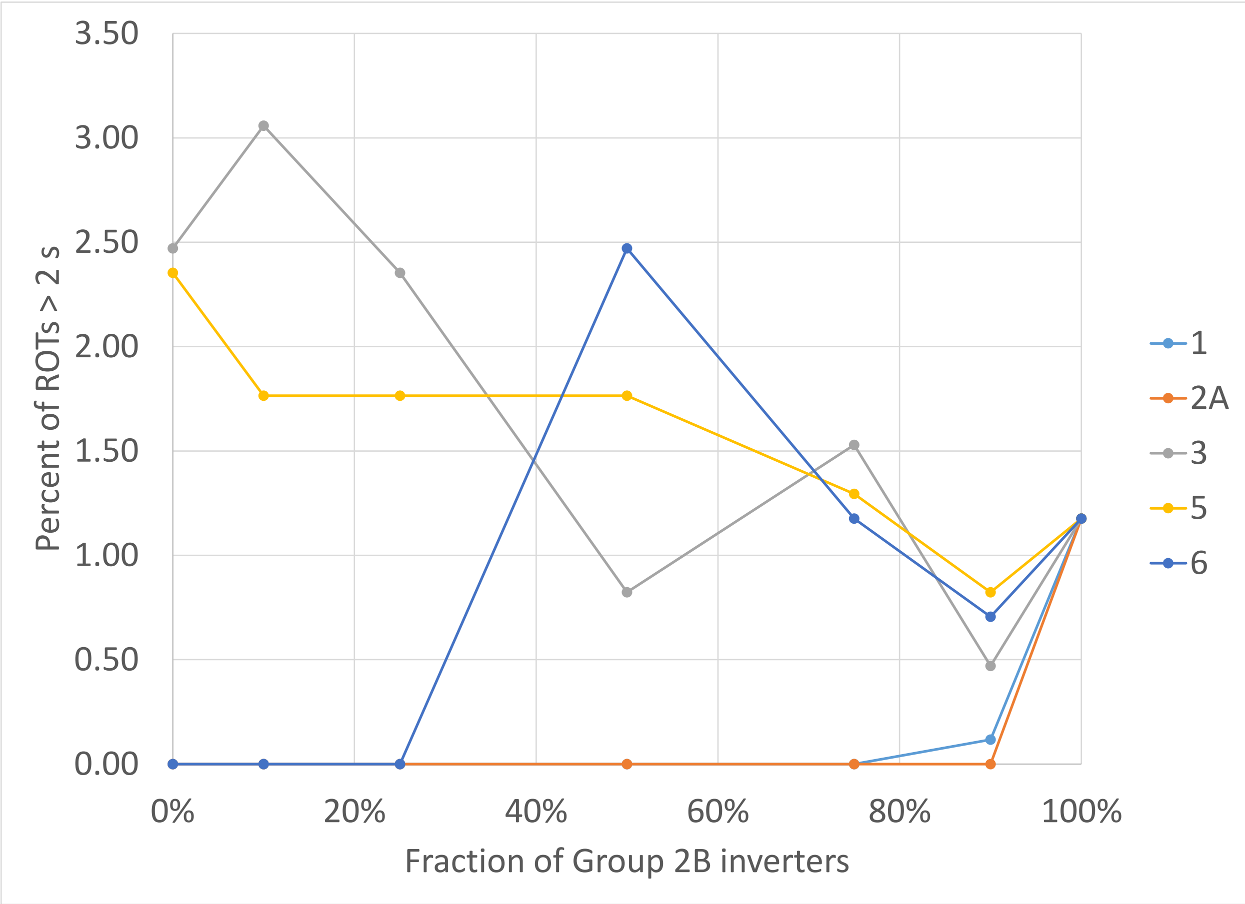

Figure 4. Plot of the number of ROTs greater than 2 s as the number of AI Group 2B inverters is varied, without RTs. The chart legend shows which type of inverter Group 2B is mixed with.

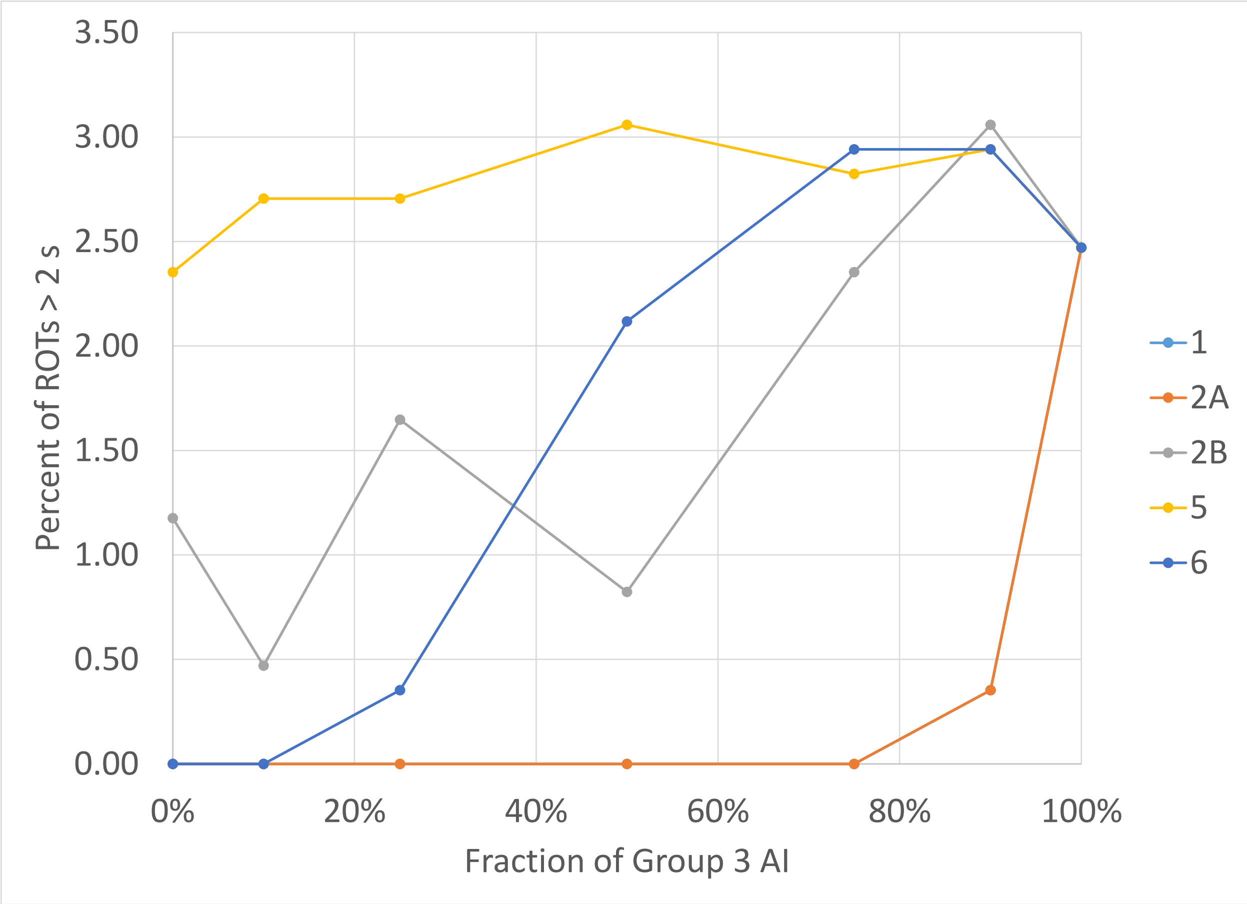

Figure 5. Plot of the number of ROTs greater than 2 s as the number of AI Group 3 inverters is varied, without RTs. The chart legend shows which type of inverter Group 3 is mixed with.

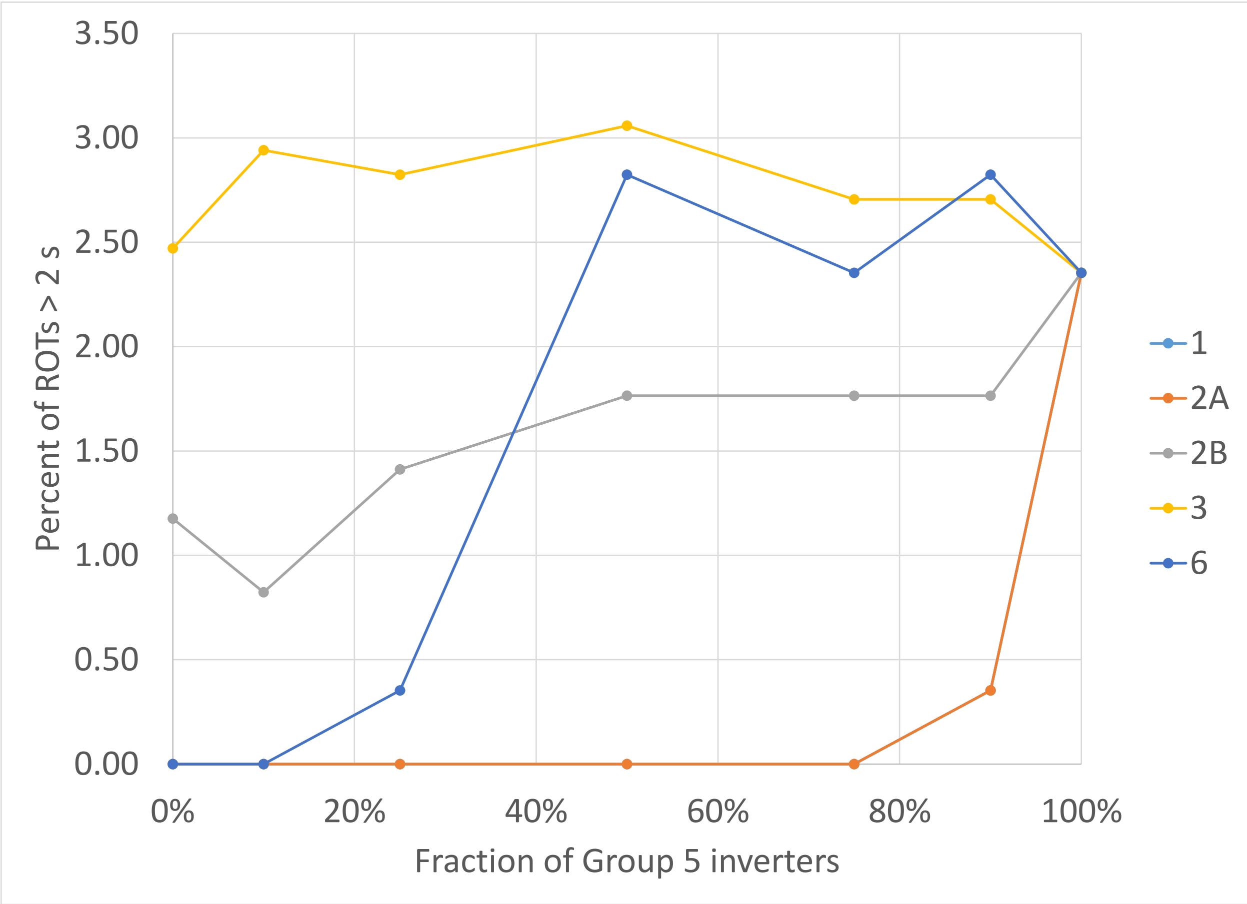

Figure 6. Plot of the number of ROTs greater than 2 s as the number of AI Group 5 inverters is varied, without RTs. The chart legend shows which type of inverter Group 5 is mixed with.

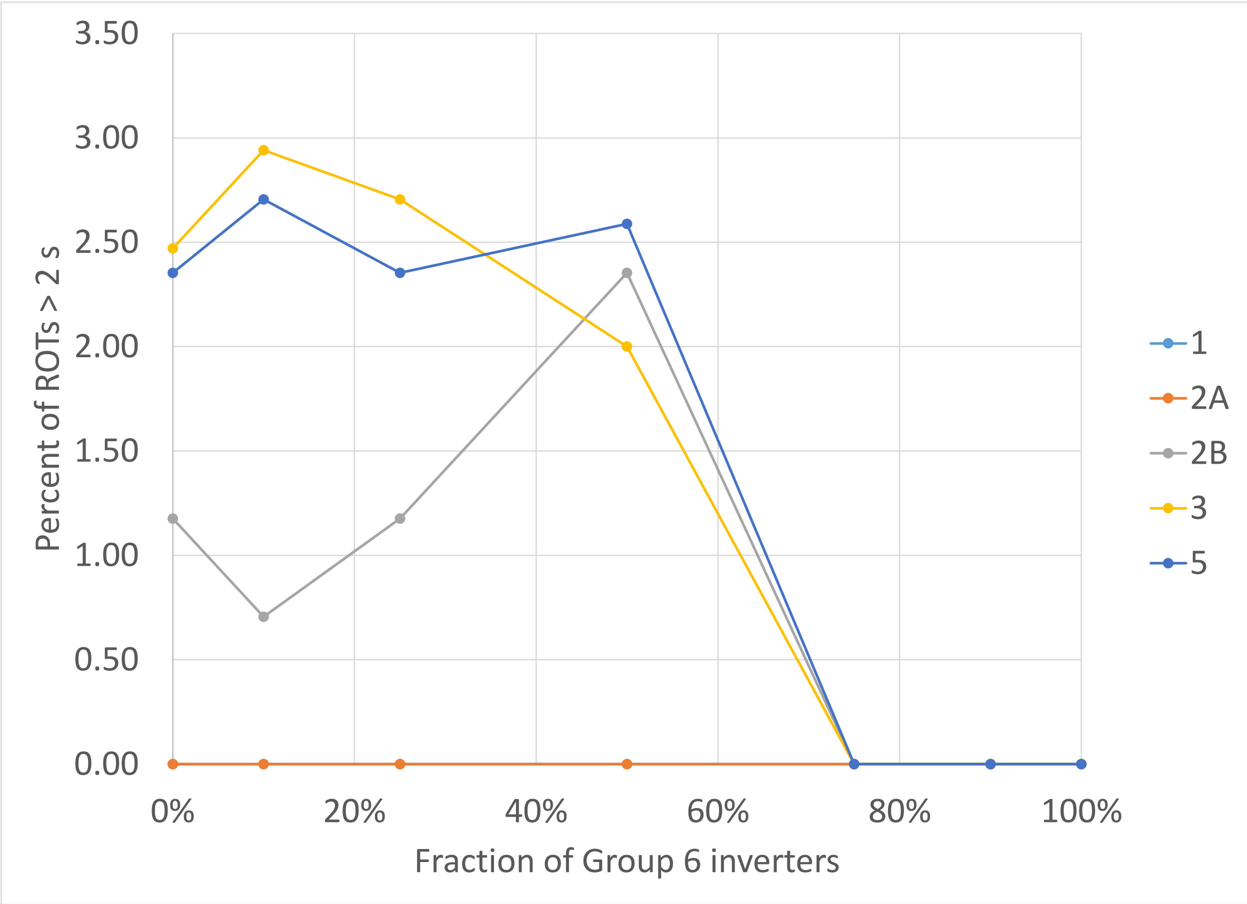

Figure 7. Plot of the number of ROTs greater than 2 s as the number of AI Group 6 inverters is varied, without RTs. The chart legend shows which type of inverter Group 6 is mixed with.

3.1.2. *Mixtures of inverters and synchronous generators, without ride-throughs*

The tables in this section contain the results of the tests in which inverters were mixed with synchronous generators, and with relays set to IEEE 1547-2003 values (no ride-throughs).

- Table 5 shows the total number of cases (out of 850) in which each Group of inverters exhibited ROTs longer than 2 s as a function of the fraction of DER that was synchronous.
- Table 6 shows the same information but expressed as a fraction of the total number of cases in which the 2-s limit was breached.
- Table 7 shows the maximum ROT detected over all 850 loading cases tested for that PV/synchronous generator combination.

Figure 8 shows a plot of the number of cases in which ROTs exceeded 2 s for each inverter example tested, as a function of the synchronous generation fraction in the island. There are three key conclusions that can be drawn from Figure 8:

1. In general, the slopes of all traces are positive, meaning that NDZ sizes increase as the fraction of synchronous generation increases for all of the inverters and indicating as expected that inclusion of synchronous generation does make islanding detection more challenging for inverters.
2. For very low synchronous generation fractions, for two of the inverters tested (2B-1 and 3), the slope of the trace is negative; the NDZ size actually *decreases* with increasing synchronous generation fraction. In these cases, there is an initial transient in both P and Q from the generator because the island does not have a precise var balance, so when the island forms the voltage phase jumps to the value dictated by the load phase angle at 60 Hz. That jump in voltage phase causes the internal power angle of the synchronous generator to suddenly increase, resulting in a small upward transient in generator output power. This in turn causes the generator's frequency to drop slightly. However, the phase change in the voltage also triggers an upward frequency "push" by the inverter anti-islanding. The inverters are much large in capacity than the synchronous generators, so they dominate the island frequency and drive it sharply upward. The synchronous generator speed controllers, which have a slower response time than the inverter controls, are not able to keep up with the change in frequency. As a result, the power angle collapses, the synchronous generator output power drops, and the generators accelerate until the overfrequency trip is reached. As the voltage drops, the synchronous generator starts to produce some vars according to the AVR's droop characteristic. The var output is enhanced somewhat because the synchronous generator's terminal voltage is falling. This var output from the synchronous generators is in the same direction as the inverters' anti-islanding "push", and the net result is that *in these cases the synchronous generator actually helps the islanding detection*, leading to shorter ROTs. In other work, this phenomenon has been observed with AI Group 1 inverters as well.
3. Some of the inverters fared much better than others in these tests.
    a. Two of the inverters, 1-1 ("pure" SFS) and 2B-2, have no ROTs over 2 so until 84% synchronous generation. There is one exception: inverter 2B-2 did exhibit a single indefinite ROT for 16.8% synchronous generation, but this is believed

to be a “lucky shot” in which the simulation grid happened to catch an exceptionally close P-Q balance in the island. Note that *all* inverter-resident islanding detection methods have this “lucky shot” case if the P and Q are *extremely* closely matched and if this close matching were preserved for the entire ROT via constant load and generation, so inverter 2B-2 should not be excessively penalized relative to the other samples on the basis of this one isolated point alone.

b. The two Group 1 inverters, 1-1 and 1-2, show significantly different performance. The 1-1 example (“pure SFS”) is the least affected by the synchronous generation of all the methods tested, but 1-2 (“CLIM”) loses effectiveness more quickly.

c. Between the two Group 2B inverters, there is a significant difference in performance. 2B-2, the inverter using “classical” SFS but with a dead zone, exhibits performance that is almost (but not quite) as good as the pure-SFS example 1-1. Example 2B-1, the inverter that has the discretized gains and the fixed low gain near 60 Hz, has more detection difficulty because in many cases the change in frequency is smaller than the discretization levels in the anti-islanding implementation, and the positive feedback effect is not triggered, resulting in no additional “push” from the inverter. As a result, this inverter sees detection failures even at very low synchronous generation fractions, although the fraction of failures as a percentage of the total number of cases is still quite low. The Group 3 inverter fails for roughly 2% of the cases tested for all synchronous generation fractions tested, but this effect is largely because of the averaging out of the impedance detection pulse over the multiple inverters and was also seen with the all-inverter cases (i.e., that particular effect is not caused by the synchronous generation). The Group 6 inverter has somewhat more difficulty with the synchronous generators than it did when facing other inverters, because the synchronous generators oppose the inverters’ attempts to change the current phase angles.

Table 5. Number of loading scenarios in which PV plant run-on times exceeded 2 s, inverter vs. sync gen cases, no RT

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0	1	7	0	21	0
	16.8%	0	1	4	1	12	0
	28.0%	0	3	5	0	12	1
	39.2%	0	5	10	0	15	13
	50.4%	0	9	12	0	18	15
	61.6%	0	13	16	1	17	19
	72.8%	4	16	19	6	19	20
	84.0%	11	23	26	13	23	24

Table 6. Table 5 information, expressed as the percent of total cases in which > 2 s run-ons were observed, no RT

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0.0%	0.1%	0.8%	0.0%	2.5%	0.0%
	16.8%	0.0%	0.1%	0.5%	0.1%	1.4%	0.0%
	28.0%	0.0%	0.4%	0.6%	0.0%	1.4%	0.1%
	39.2%	0.0%	0.6%	1.2%	0.0%	1.8%	1.5%
	50.4%	0.0%	1.1%	1.4%	0.0%	2.1%	1.8%
	61.6%	0.0%	1.5%	1.9%	0.1%	2.0%	2.2%
	72.8%	0.5%	1.9%	2.2%	0.7%	2.2%	2.4%
	84.0%	1.3%	2.7%	3.1%	1.5%	2.7%	2.8%

Table 7. Maximum PV plant ROTs (in seconds) seen for all cases in inverter-vs-sync gen cases, no RTs

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0.34	2.15	10	0.54	10	0.45
	16.8%	0.52	2.01	10	10	10	0.52
	28.0%	0.46	2.81	10	0.66	10	2.16
	39.2%	0.51	3.73	10	0.89	10	10
	50.4%	0.72	5.97	10	1.65	10	10
	61.6%	1.02	10	10	3.02	10	10
	72.8%	5.56	10	10	6.2	10	10
	84.0%	10	10	10	10	10	10

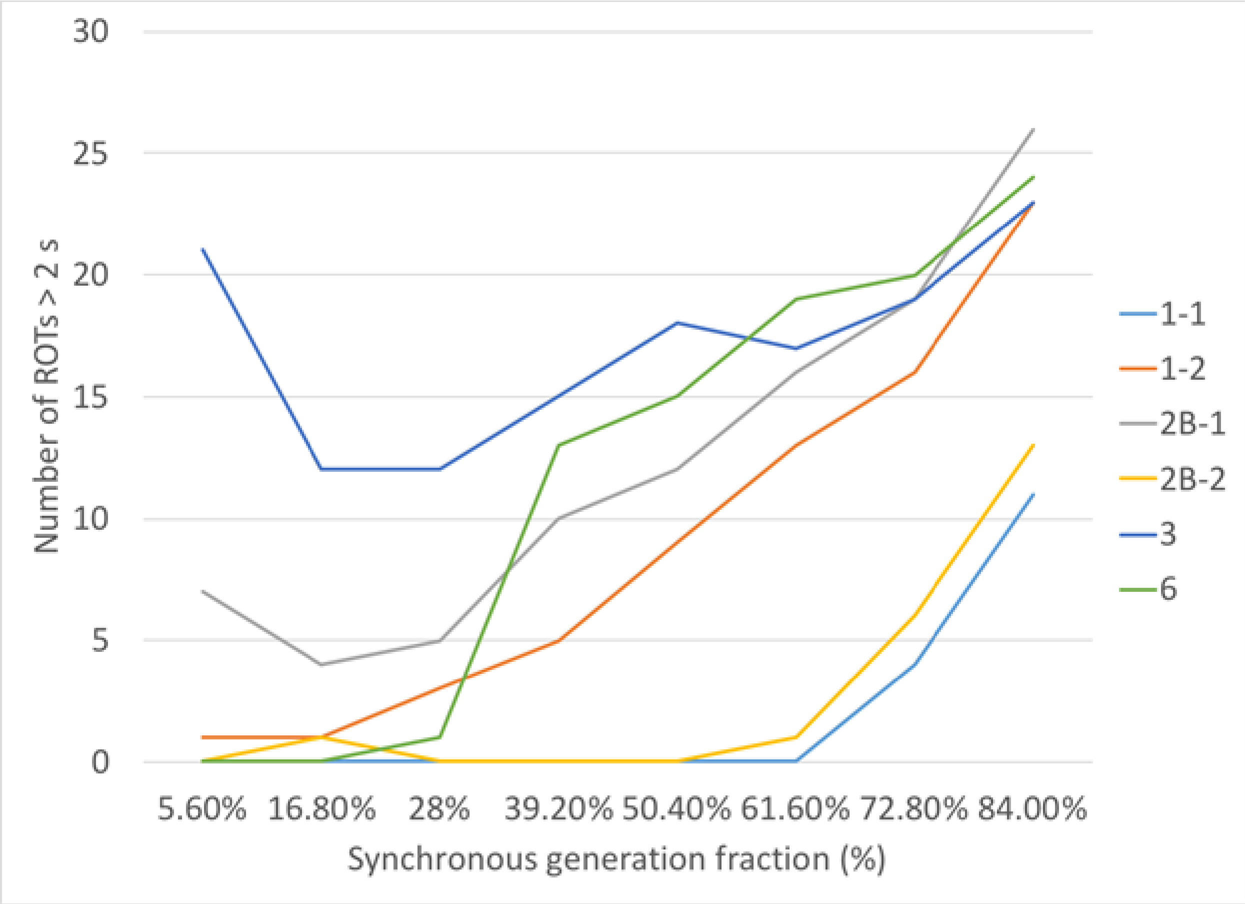

Figure 8. Number of loading scenarios in which ROTs exceeded 2 s for each inverter example tested, as a function of the fraction of synchronous generation within the island, without RTs.

3.2. Results with Ride-Throughs

3.2.1. Mixtures of dissimilar inverters, with ride throughs

The tables in this section show results obtained with mixtures of dissimilar inverters. The inverters used here are the same ones used in the mixtures-of-inverters cases without ride-throughs (RTs) reported above. In these tests with RTs active, Group 4 was not evaluated. The tables are as follows:

- Table 8 shows the number of loading cases for each combination and proportionality that led to an ROT exceeding 2 s.
- Table 9 shows the same data as Table 8, except expressed as a fraction of the 850 loading scenarios in which ROTs exceeded 2 s.
- Table 10 shows the maximum ROT seen for each combination, over all 850 loading scenarios tested for each DER combination.

Comparing Table 9 with Table 3, it can be seen that for all but two of the combinations the addition of RTs to the inverters degraded the islanding detection capabilities of the inverters, and for some combinations of Groups the degradation was significant, with both the numbers of excessive ROTs and the maximum lengths of ROTs increasing. Thus, *in general* one may conclude that RTs will increase the difficulty in detection of unintentional islands, all other factors being equal.

There were two combinations of methods that remained fully effective for all proportions tested even with RTs active, for the all-inverter cases: combinations of Groups 1 ("pure" SFS) and 2A (SFS with saturation limits), and combinations of Groups 2A (SFS with saturation limits) and 6 (negative-sequence positive feedback by shifting the angles between adjacent phase currents).

Table 8. Number of loading scenarios in which ROTs exceeded 2 s, inverter-vs-inverter case, with RTs

Vs	Amount of Class 1					Vs	Amount of Class 3				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
2A	0	0	0	0	0	1	32	43	3	4	48
2B	46	2	0	0	0	2A	1	0	3	2	26
3	48	2	0	0	0	2B	113	118	119	119	113
5	47	1	0	0	0	5	117	120	122	117	115
6	43	0	0	0	0	6	112	126	129	119	116
Vs	Amount of Class 2A					Vs	Amount of Class 5				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
1	0	0	0	0	0	1	35	42	3	3	47
2B	28	0	0	0	0	2A	0	1	3	2	23
3	26	0	0	0	0	2B	112	116	118	117	112
5	23	0	0	0	0	3	118	119	122	117	114
6	0	0	0	0	0	6	124	122	134	117	115
Vs	Amount of Class 2B					Vs	Amount of Class 6				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
1	37	56	8	2	46	1	0	0	0	0	43
2A	2	2	4	0	28	2A	0	0	0	0	0
3	115	118	119	114	107	2B	105	120	125	0	0
5	114	117	118	114	108	3	116	118	116	0	0
6	96	114	138	120	105	5	112	116	120	0	0

Table 9. Table 8 information, expressed as the percent of total cases in which a 2 s ROT was observed, inverter-vs-inverter with RTs

Vs	Amount of Class 1 DG				
	0.1	0.3	0.5	0.8	0.9
2A	0.0	0.0	0.0	0.0	0.0
2B	5.4	0.2	0.0	0.0	0.0
3.0	5.6	0.2	0.0	0.0	0.0
5.0	5.5	0.1	0.0	0.0	0.0
6.0	5.1	0.0	0.0	0.0	0.0

Vs	Amount of Class 3 DG				
	0.1	0.3	0.5	0.8	0.9
1.0	3.8	5.1	0.4	0.5	5.6
2A	0.1	0.0	0.4	0.2	3.1
2B	13.3	13.9	14.0	14.0	13.3
5.0	13.8	14.1	14.4	13.8	13.5
6.0	13.2	14.8	15.2	14.0	13.6

Vs	Amount of Class 2A DG				
	0.1	0.3	0.5	0.8	0.9
1.0	0.0	0.0	0.0	0.0	0.0
2B	3.3	0.0	0.0	0.0	0.0
3.0	3.1	0.0	0.0	0.0	0.0
5.0	2.7	0.0	0.0	0.0	0.0
6.0	0.0	0.0	0.0	0.0	0.0

Vs	Amount of Class 5 DG				
	0.1	0.3	0.5	0.8	0.9
1.0	4.1	4.9	0.4	0.4	5.5
2A	0.0	0.1	0.4	0.2	2.7
2B	13.2	13.6	13.9	13.8	13.2
3.0	13.9	14.0	14.4	13.8	13.4
6.0	14.6	14.4	15.8	13.8	13.5

Vs	Amount of Class 2B DG				
	0.1	0.3	0.5	0.8	0.9
1.0	4.4	6.6	0.9	0.2	5.4
2A	0.2	0.2	0.5	0.0	3.3
3.0	13.5	13.9	14.0	13.4	12.6
5.0	13.4	13.8	13.9	13.4	12.7
6.0	11.3	13.4	16.2	14.1	12.4

Vs	Amount of Class 6 DG				
	0.1	0.3	0.5	0.8	0.9
1.0	0.0	0.0	0.0	0.0	5.1
2A	0.0	0.0	0.0	0.0	0.0
2B	12.4	14.1	14.7	0.0	0.0
3.0	13.6	13.9	13.6	0.0	0.0
5.0	13.2	13.6	14.1	0.0	0.0

Table 10. Maximum ROTs (in seconds) seen for all cases in Table 8 and Table 9, with RTs

Vs	Amount of Class 1					Vs	Amount of Class 3				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
2A	0.5	0.3	0.3	0.4	0.4	1	2.3	10	10	10	10
2B	10	4.1	0.7	0.6	0.4	2A	2.2	0.5	10	10	10
3	10	2.3	0.7	0.5	0.4	2B	10	10	10	10	10
5	10	2.3	0.9	0.5	0.4	5	10	10	10	10	10
6	2.3	0.9	0.7	0.7	0.4	6	2.4	10	10	10	10
Vs	Amount of Class 2A					Vs	Amount of Class 5				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
1	0.6	0.5	0.5	0.5	0.5	1	2.4	10	10	10	10
2B	10	0.8	0.6	0.6	0.5	2A	0.5	10	10	10	10
3	10	1.5	0.5	0.5	0.5	2B	10	10	10	10	10
5	10	1.1	0.6	0.5	0.5	3	10	10	10	10	10
6	1.7	1	0.6	0.5	0.5	6	2.4	10	10	10	10
Vs	Amount of Class 2B					Vs	Amount of Class 6				
	10%	25%	50%	75%	90%		10%	25%	50%	75%	90%
1	2.3	10	10	3.9	10	1	0.6	0.7	0.7	0.6	0.5
2A	2.2	10	10	0.8	10	2A	0.7	0.5	0.6	0.6	0.5
3	10	10	10	10	10	2B	10	10	10	0.6	0.5
5	10	10	10	10	10	3	10	10	10	0.6	0.6
6	2.3	10	10	10	10	5	10	10	10	0.6	0.6

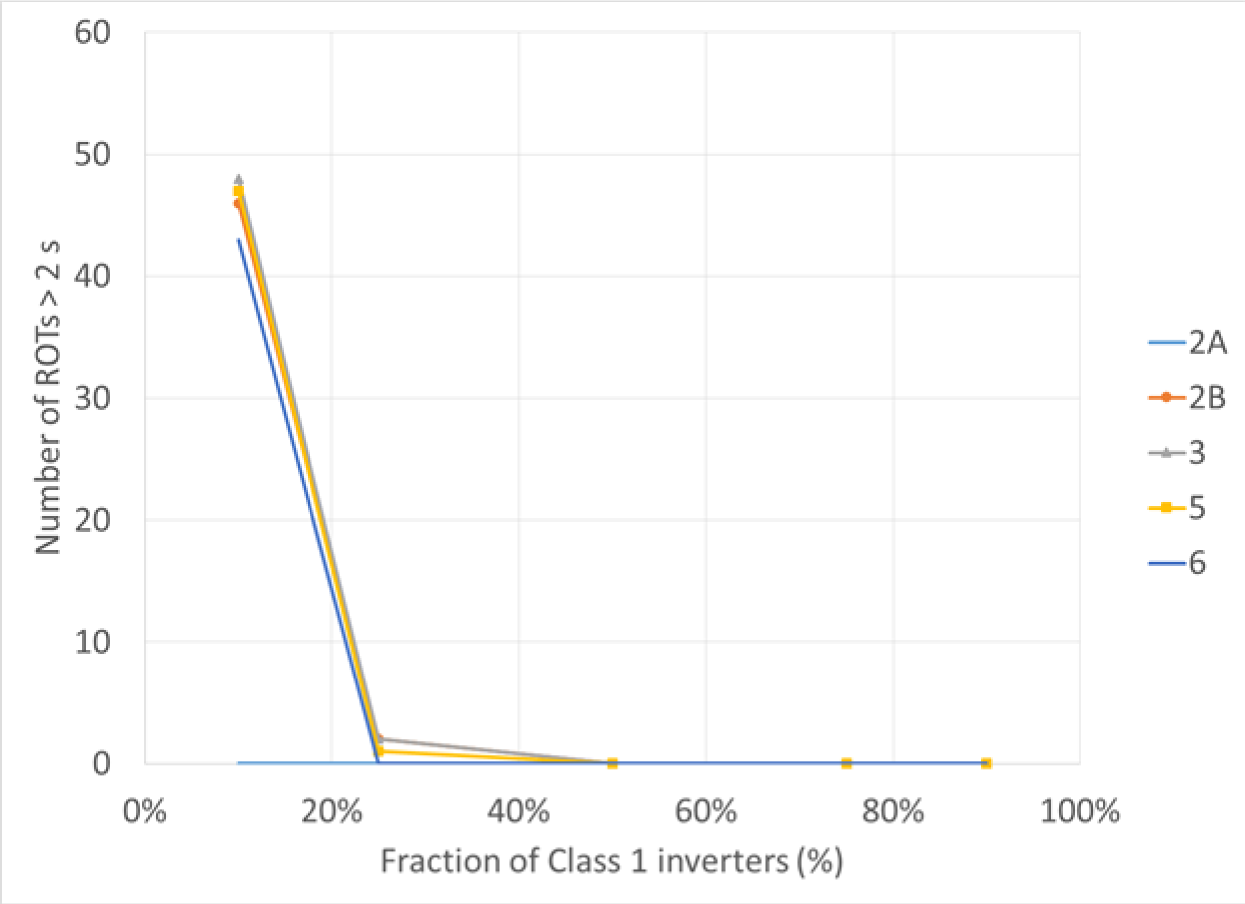

Figure 9. Plot of the number of ROTs greater than 2 s as the number of AI Group 1 inverters is varied, with RTs. The chart legend shows which type of inverter Group 1 is mixed with.

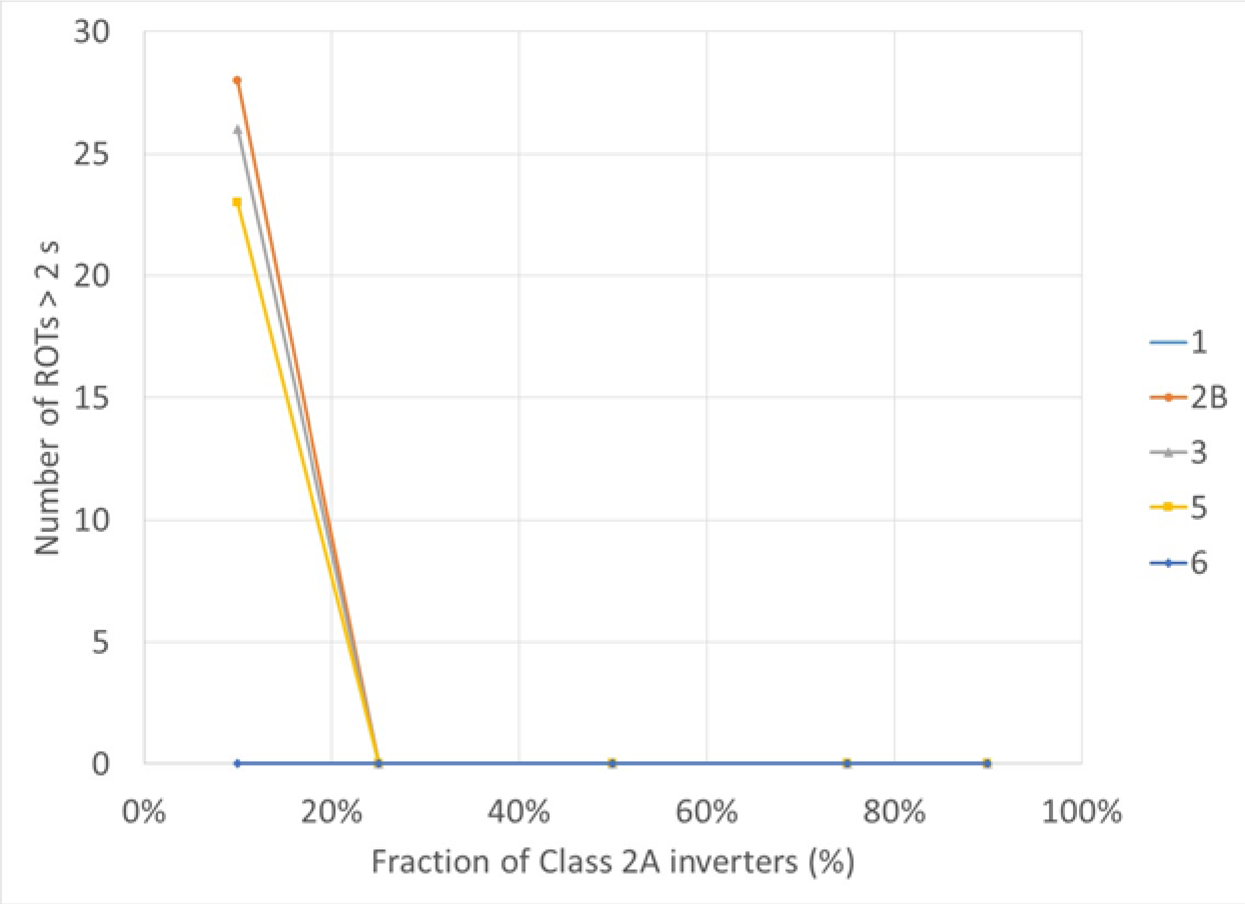

Figure 10. Plot of the number of ROTs greater than 2 s as the number of AI Group 2A inverters is varied, with RTs. The chart legend shows which type of inverter Group 2A is mixed with.

Figure 11. Plot of the number of ROTs greater than 2 s as the number of AI Group 2B inverters is varied, with RTs. The chart legend shows which type of inverter Group 2B is mixed with.

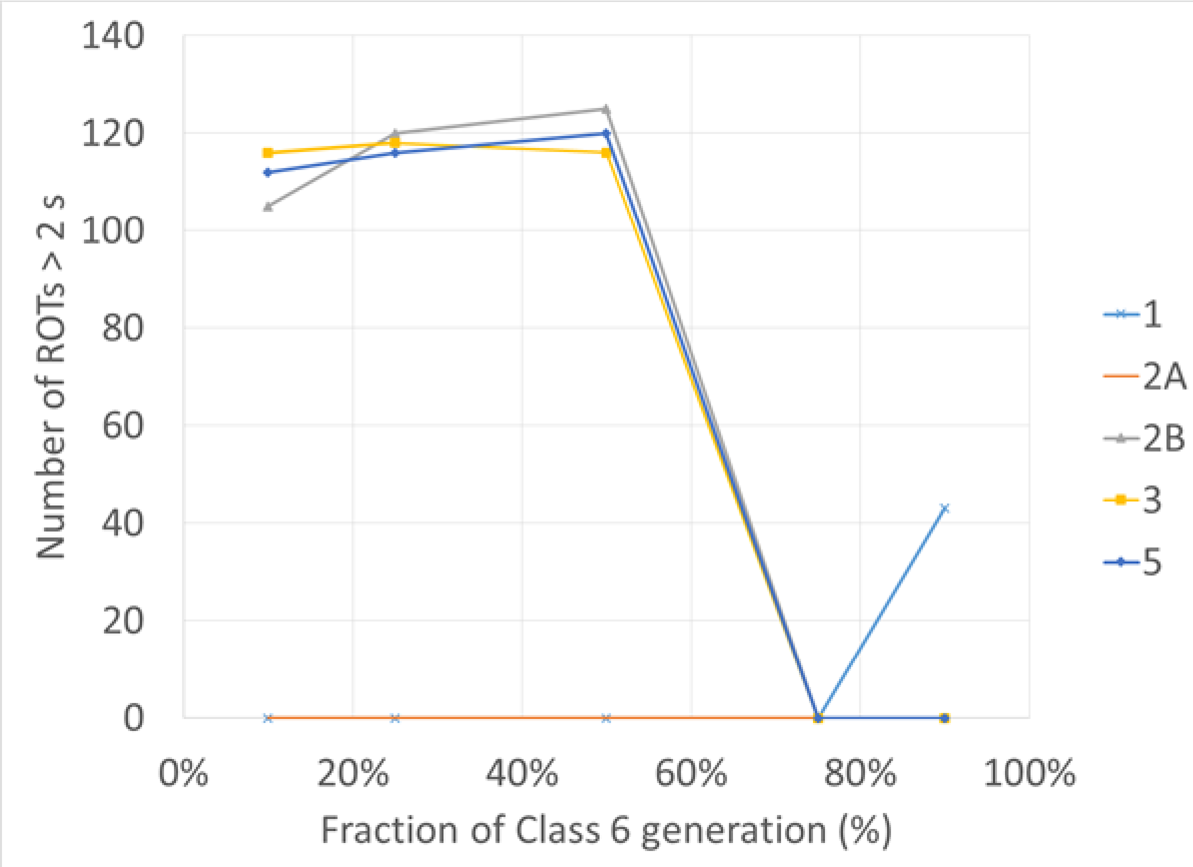

Figure 12. Plot of the number of ROTs greater than 2 s as the number of AI Group 6 inverters is varied, with RTs. The chart legend shows which type of inverter Group 6 is mixed with.

3.2.2. *Mixtures of inverters and synchronous generators, with RTs*

The tables in this section show results for simulations with mixtures of inverters and synchronous generators, with RTs active (relays set to IEEE 1547-2018 settings). The inverter types used here are the same as those used in the previous set of inverter vs. synchronous generator simulations. The contents of the tables are as follows:

- Table 11 shows the total number of cases (out of 850) in which each Group of inverters exhibited ROTs longer than 2 s as a function of the fraction of DER that was synchronous.
- Table 12 shows the same information but expressed as a fraction of the total number of cases in which the 2-s limit was breached.
- Table 13 shows the maximum ROT detected over all 850 loading cases tested for that PV/synchronous generator combination.

Comparing cases with and without RTs, and in particular comparing Table 12 with Table 6, shows that the introduction of the RTs degraded the ability of these particular inverters to detect formation of an unintentional island when a synchronous generator is also present in the island, and also that the overall risk, in terms of the fraction of cases in which an island may not be detected in 2 s, rose with the introduction of RTs. Inverter 1-1 fared best, with no ROTs over 2 s up to a synchronous generation fraction of about 40%. Part of the reason for this is the effect described above in which the synchronous generators actually *help* detect the island when the synchronous generation fraction is small and the frequency changes very rapidly. Group 2B-1 also showed no ROTs over 2 s, except for one outlier for the 16.8% sync gen tests[2]. The Group 6 inverters remained effective up to a synchronous generation fraction of 16.8%, but above that level the fraction of cases in which the Group 6 inverters run on for more than 2 s rises quickly and the maximum ROT goes to 10 s because the inverters cannot change the angle between phase currents as readily when there is a synchronous generator present.

Table 11. Number of loading scenarios in which ROTs exceeded 2 s, inverter-vs-sync gen cases, with RT

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0	16	0	89	104	0
	16.8%	0	33	1	101	114	0
	28.0%	0	64	0	118	125	8
	39.2%	0	99	0	148	144	115
	50.4%	2	117	1	173	162	189
	61.6%	10	143	9	203	183	210
	72.8%	62	173	72	228	203	224
	84.0%	128	221	158	264	235	261

[2] This extended ROT is believed to occur because by luck of the draw the simulation grid included one point that produced an *extremely* precise match in real and reactive power within the island, and that is why it is considered an outlier that is not generally representative of the performance of Group 2B.

Table 12. Table 11 information, expressed as the percent of total cases in which ROTs > 2 s were observed, with RT

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0.0%	1.9%	0.0%	10.5%	12.2%	0.0%
	16.8%	0.0%	3.9%	0.1%	11.9%	13.4%	0.0%
	28.0%	0.0%	7.5%	0.0%	13.9%	14.7%	0.9%
	39.2%	0.0%	11.6%	0.0%	17.4%	16.9%	13.5%
	50.4%	0.2%	13.8%	0.1%	20.4%	19.1%	22.2%
	61.6%	1.2%	16.8%	1.1%	23.9%	21.5%	24.7%
	72.8%	7.3%	20.4%	8.5%	26.8%	23.9%	26.4%
	84.0%	15.1%	26.0%	18.6%	31.1%	27.6%	30.7%

Table 13. Maximum PV plant ROTs seen for all cases in Table 11 and Table 12, with RTs

	PV AI class	1-1	1-2	2B-1	2B-2	3	6
Sync gen fraction	5.6%	0.4	3.09	0.68	10	10	0.48
	16.8%	0.42	5.14	10	10	10	0.56
	28.0%	0.49	4.72	1.04	10	10	10
	39.2%	0.61	6.47	1.25	10	10	10
	50.4%	2.5	10	2.61	10	10	10
	61.6%	7.47	10	4.73	10	10	10
	72.8%	10	10	7.96	10	10	10
	84.0%	10	10	10	10	10	10

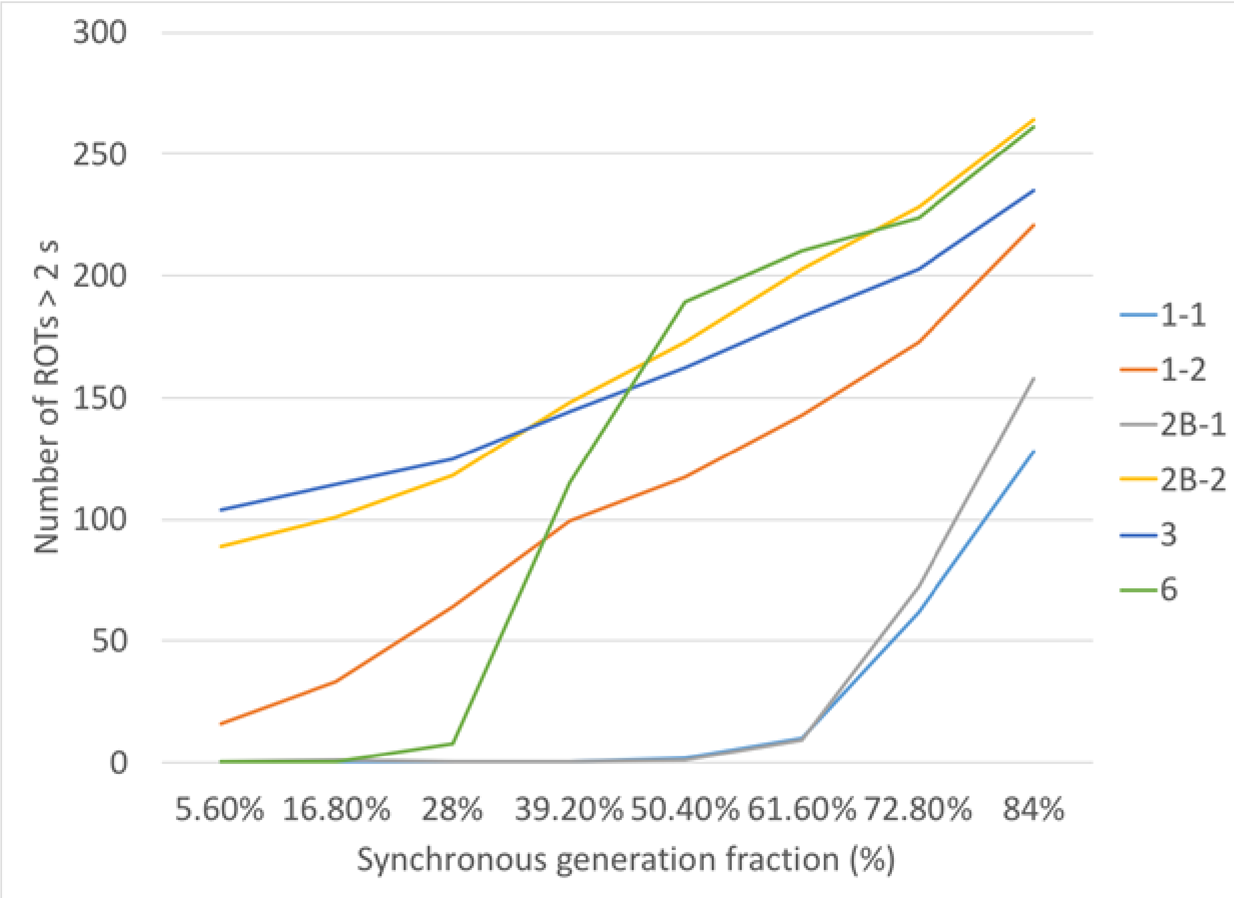

Figure 13. Number of loading scenarios in which ROTs exceeded 2 s for each inverter example tested, as a function of the fraction of synchronous generation within the island, with RTs.

4. CONCLUSIONS

The simulation results and analysis presented here support the following conclusions:

1. Inverters using anti-islanding from Groups 1 and 2A tended to perform much better than examples from other groups. These two groups maintained effectiveness for all combinations of inverters, combinations of inverters and synchronous generators, and when RTs were added, until the fraction of Group 1 or 2A inverters in the island became very low.
2. In general, the addition of ride-throughs does degrade the performance of islanding detection methods. NDZ sizes and maximum ROTs tended to increase when RTs were added.
3. When islanding detection methods are combined in an island, *generally*, the combination of methods is less effective in detecting an island than either method alone, although the data are somewhat noisy and contain several points that do not fully follow this trend. The exception to this general rule was when one of the methods in the island was Group 1 or 2A, in which that Group tended to dominate the island so that the performance of any other Group improved when Group 1 or 2A was present.
4. In general, the presence of synchronous machines does make islanding detection more difficult. This is not surprising, but what *was* interesting was that for certain examples (1-1 and 2B-1), the islands were still detected in less than 2 s when synchronous generation fractions were quite high. For example, for Group 1-1, islands were still reliably detected in under 2 s when over 62% of the generation in the island was synchronous.

In an ongoing effort to address the impacts of and inform the industry about high-penetration and “smart-inverter” factors affecting the ability of DERs to detect unintentional islands, Sandia is partnering with the Electric Power Research Institute (EPRI) and a number of utilities on additional future research.

5. LIMITATIONS OF THIS STUDY

As has been noted previously, this study includes the effects of RTs, but not the effects of regulation functions such as volt-var or frequency-watt droops. The impacts of those functions on islanding detection effectiveness are reported in a separate SAND report.

As noted above, this work did not consider any representatives of AI Groups 2C or 4.

All loading conditions tested in this work were weighted equally, but in reality not all of the loading conditions tested; for example those lying at relatively high or low power factors are equally likely in the field. In general the loads least likely to occur in the field also *tend* to lead to shorter ROTs, meaning that the fraction of points at which ROTs exceeded 2 s can give an artificially low impression of the true risk posed by the excessive ROTs. It would be beneficial to develop a weighting system for the various loading conditions, and then use this in some form of risk-of-islanding index.

Higher-resolution data are nearly always desirable, and this study is no exception. In particular:

- It would be beneficial to perform the batches with a higher-resolution grid of loading conditions.
- It would be instructive to perform this same study with a larger number of inverter examples.
- It would be desirable to have smaller increments in the various generation fractions studied.

Of course, any of these changes would require a concomitantly longer simulation time.

Real-world inverter examples were selected for this work for a variety of reasons, but it would be of value to perform the same sweeps using generic inverters that represent the AI Groups reasonably.

In the RT cases with synchronous generation, the synchronous generators were assumed to have the same RT settings as the inverters. In reality, that will probably not be the case; inverters may comply with IEEE 1547-2018 "Category III", but synchronous generation will in general probably still be "Category I". Thus, it might be beneficial to redo the PV + synchronous generator case with RT simulations with the relays set as just described, i.e. Category III inverters with Category I synchronous generators.

One conclusion reached by this study is that two Groups, Groups 1 and 2A, outperformed the others. This would suggest that in a global sense islanding risk could be reduced if all inverters used methods from those two groups, and thus perhaps those should be adopted as some kind of an industry standard. However, that suggestion could be premature because this study did not explore the potential power quality or system stability impacts of having high penetrations of inverter-based DERs all using islanding detection methods from those two groups, particularly on weak grids.

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