Republic of the Marshall Islands
Energy Future

Electricity Roadmap

Technical Note 05:
RMI Suggested Service Levels

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Summary

Establishing service levels for an island power system helps define which enabling technologies should be used during its journey to 100% renewable generation.

This document discusses key service level requirements for electricity supply to the Marshall Islands and proposes their values. All service level requirements are presented in Section 3 of this document.

1 Background / Introduction

This memo considers and proposes network service level targets for:

1. Majuro grid
2. Outer Island grids
3. Single household independent supplies

The service levels considered are for supply voltage, supply frequency, generation security, distribution security and supply reliability.

Whilst cost metrics (e.g. customers per utility full-time employee) and cost per kWh are not considered, the trade-off between service level and cost is considered in that seeking too high a level of service would come at a cost that the consumers would be unlikely willing to pay. This includes service levels such as frequency keeping where specifying too high a tolerance would require greater system inertia with increased installed plant costs.

The main motivation for specifying service levels is the move towards displacing tradition diesel generation to meet greenhouse CO_2 targets. For electricity generation, this will be achieved with new centralised renewable energy plant (e.g. solar farms, wind farms) and with distributed renewable generation (mainly roof-top solar). The integration of this diesel displacement plant into the grids requires target electricity service levels to appropriately inform the integration designs.

1.1 Assumptions

The key assumptions made are as follows:

1. The system will remain based on the US standard of 60Hz with customer appliances conforming to US standard voltages (e.g. 120V, 208V, 240V, 277V, 480V) as per standard ANSI C84.1 and with appliances conforming to NEMA standards.
2. The supply systems will be solidly earthed (as high fault levels are not generally an issue in small island networks).
3. That the supply networks must remain robust to faults within the distributed part of the network (where protection co-ordination applies) and to expected events (e.g. starting of known loads or the restoration of a feeder after maintenance).
4. Customers will not accept deterioration from the current service levels.
5. While service levels may be improved, this should not come at significant additional cost.
6. Network maintenance will not include live-line work as a means to improve service availability. This is based on the assumption that small island utilities have insufficient resources to manage the safety aspects of such work practices.
7. Recognition of the lack of ready access to plant spares and the manufacturer's service personnel. This means plant outages or overhauls may extend significantly in time.
8. A reduced ability of the utility to retain skilled trade staff and technicians together with often insufficient maintenance budgets. This leads to poor maintenance, generators being run past maintenance run-hour targets and a higher instance of plant faults and plant deratings.
9. That the incidence of more and longer generator outages requires a higher generator plant reserve (i.e. generator security level).

10. That the networks must always operate safely in terms of detecting and disconnecting faults within an appropriate time.
11. That the network will continue to develop with both centralised (utility scale) renewable energy generation and customer (behind the meter) distributed renewable generation.

2 Service Levels Criteria

2.1 Generation Security

Generation Security criteria implies that there always has to be enough diesel generator capacity to meet the load.

For Majuro and Ebeye grid:

N-2[1] security on firm (diesel) capacity.

This allows for 1 diesel generator to be out for maintenance and another to fail while still covering the customer load and without relying on renewable energy or battery supply (that may not be available, for example, after a number of continuously cloudy days).

For Medium Island power systems grid:

N-2 security including renewable (non-firm) capacity.

This is in recognition of the lower maintenance afforded to generation plant in these remote networks and their consequent lower reliability and longer outage times but also in the lower economic impact from a more sustained outage in relation to a larger or principal network.

For grid independent customers (when provided to the customer as an alternative to a grid connection):

N security.

This is in recognition of the limited impact of the plant outage given it only affects a single customer and that the capital cost of a higher level of security would be uneconomic.

2.2 Distribution Network Security

Grid Security criteria implies that there should be redundant paths in the distribution network to ensure continuous supply to customers, even during faults.

For Majuro and Ebeye grid:

N-1 security on inter-connect transformers (transformers that connect the generator bus to the MV distribution bus – if applicable). N security on network lines and other network assets.

[1] "N" being the number of a particular component of an electricity system. "N-1" security being that the electricity system still operates with full functionality if 1 of the N components fails or is out of service. "N-2" security being if 2 of the components fail or are out of service. "N" security being a single component failure will compromise service delivery.

For Medium Island power systems:

N security on all network assets

Off-grid consumers:

Not applicable

For control and protection of grid assets at power station/substation:

Single protection relays. (N)

DC system redundancy:

Single DC system is adequate (N), with two batteries each 50% of the rated capacity of the DC system, and redundant battery chargers. (N-1)

2.3 Voltage

Voltage levels need to stay within a defined range, to ensure safe and proper operation of household appliances.

Service level voltage is considered under three aspects:

- service voltage allowance for continuous supply (mainly influenced by the consumer's appliance's tolerance plus allowance for volt-drop within the consumers own wiring);
- short time over and under voltage (leading to a voltage-time 'envelope' allowance); and
- limitation of rapid voltage variation termed 'flicker' that may lead to annoyance, most often experienced through flickering lights.

Consumer voltage and appliance requirements are taken as conforming to ANSI C84.1, as described in Table 1 below, and the ITIC 1996 voltage-time curve provided in Figure 1 following[2]

Table 1 - Continuous voltage allowance ranges

Nominal	*Service*	*Utilization*	*Nameplate*	*NEMA*
Standard	-5%, +5%	-13%, +6%	Motor	-10%, +10%
120	114 – 126	104.4 – 127.2	115	103.5 – 126.5
208	197.6 – 218.4	181 – 220.5	200	180 – 220
240	228 – 252	208.9 – 254.4	230	207 – 253
277	263.2 – 290.9	241 – 293.6		
480	456 – 504	417.6 – 508.8	460	414 - 506
	Bandwidth 10%	Bandwidth 19%		Bandwidth 20%

[2] ANSI C84.1 describes two voltage ranges; range A and a wider range B. Whilst equipment is expected to function over the wider range B, this is for non-permanent arrangements with the intention the electricity service is returned to the narrower range A. The table set out here refers to the range A limits.

The 'Service' voltage is the utility delivery to the point of connection; the 'Utilisation' voltage allows for voltage drop within the consumers wiring. Appliance 'Nameplate' voltage is usually less than the 'Nominal' voltage to centre the appliance voltage variation at a lower level in recognition of the voltage drop through the service wiring.

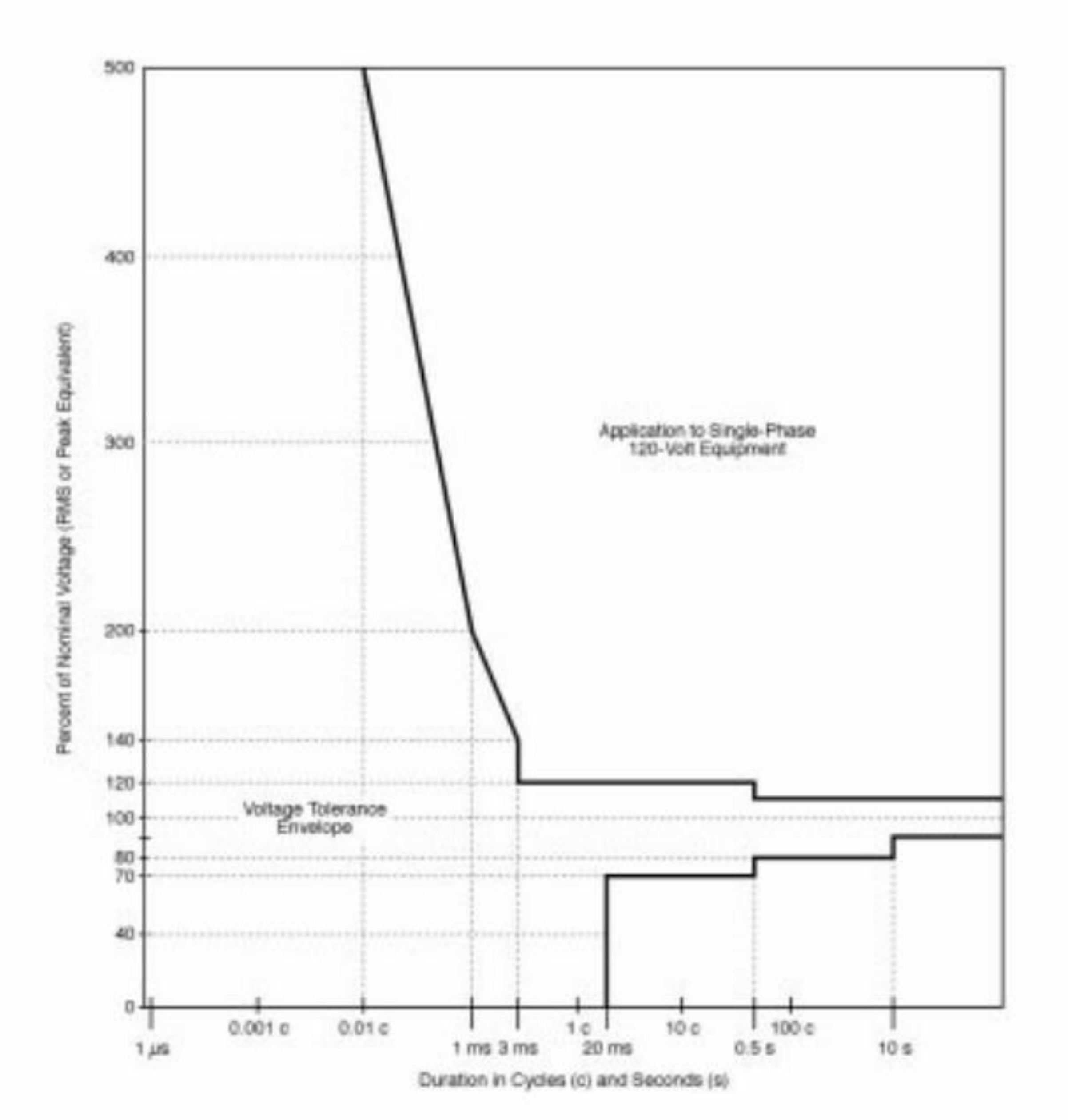

Figure 1 - ITIC 1996 curve for LV equipment time-voltage tolerance

The NEMA specification for motors and generators (NEMA MG-1) provides for:

- Voltage +/- 10% of nameplate voltage
- Frequency +/- 5% of nameplate frequency
- Supply voltage unbalance <= 1%

Alternatives in North America exist; Canadian standard CAN3-C235-83 requires utility supply to the customer service entrance on a continuous basis (>= 3 secs) as presented in Table 2:

Table 2 - Voltage allowance from Canadian Standard CAN3-C235-83

Nominal Voltage (RMS V)	Allowable Deviation for Nominal (%)	Normal Minimum Voltage (RMS V)	Normal Maximum Voltage (RMS V)	Reference
120 V / 240 V	+4.17%, -8.33%	110 V / 220 V	125 V / 250 V	At Service Entrance per CSA CAN3-C235-83 Table 3.0
120 V / 208 Y	+4.17%, -6.67%	112 V / 194 Y	125 V / 216 Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0
347 V / 600 Y	+3.75%, -8.33%	318 V / 550 Y	360 V / 625 Y	At Service Entrance per CSA CAN3-C235-83 Table 3.0

In this standard, a greater portion of the utilisation voltage is attributed to the utility. In small island networks, customer loads are typically low and seeing high voltage regulation within the customers wiring would not be expected. Additionally, as the island networks develop with increased distributed generation, the capacity for that generation to impact across customer connections, and therefore within the utility’s domain, will increase. Allowing a “middle ground” approach of specifying a utility voltage to the point of supply of +5% to -8% may be more practical that keeping within ANSI C84.1 as it allows greater range within the utility supply to accommodate the voltage variation from distributed generation and the consequent reduced ability of the utility to set the distribution transformer taps appropriately.

The above discussion refers to service voltage to consumers supplied on a continuous basis. Further allowance for low voltage single phase equipment is described in the ITIC 1996 voltage-time curve (as used in IEEE 1100:1999) as illustrated in Figure 1 above where the y-axis is percent of nominal voltage and the x-axis is time (in both cycles at 60Hz and in seconds). The main point of interest for this discussion is the allowance to 80% voltage for up to 10 seconds as this forms the basis for momentary volt drop allowance on motor start-up.

Utility voltage supply to the consumers point of connection could therefore be standard voltage within the range +5% to -8% on a continuous basis with an allowance to -15% at the point of connection for up to 10 seconds. This rule should apply for grids and customers across all island types within the RMI. From the above. The proposed voltage standard for continuous voltage delivery (to point of customer connection) for all types of power systems in Republic of Marshall Islands (RMI) are given in Table 3.

Table 3 - Proposed voltage allowance for the RMI power systems

Nominal Voltage (RMS V)	Allowable Voltage Deviation (%)	Normal Minimum Voltage (RMS V)	Normal Maximum Voltage (RMS V)
120	+5%, -8%	110.4	126
208	+5%, -8%	191.36	218.4
240	+5%, -8%	220.8	252
277	+5%, -8%	254.84	290.85
480	+5%, -8%	441.6	504

2.4 Voltage Flicker

Short-term voltage variations which arise due to connection/disconnection of large loads and/or unmodified solar and wind generation is called Voltage Flicker, and usually manifested as flickering of lights.

Additionally, voltage flicker limits need to be specified and in this regard IEEE 519:1992 refers to the earlier General Electric work on customer perception as per the chart in Figure 2 below.

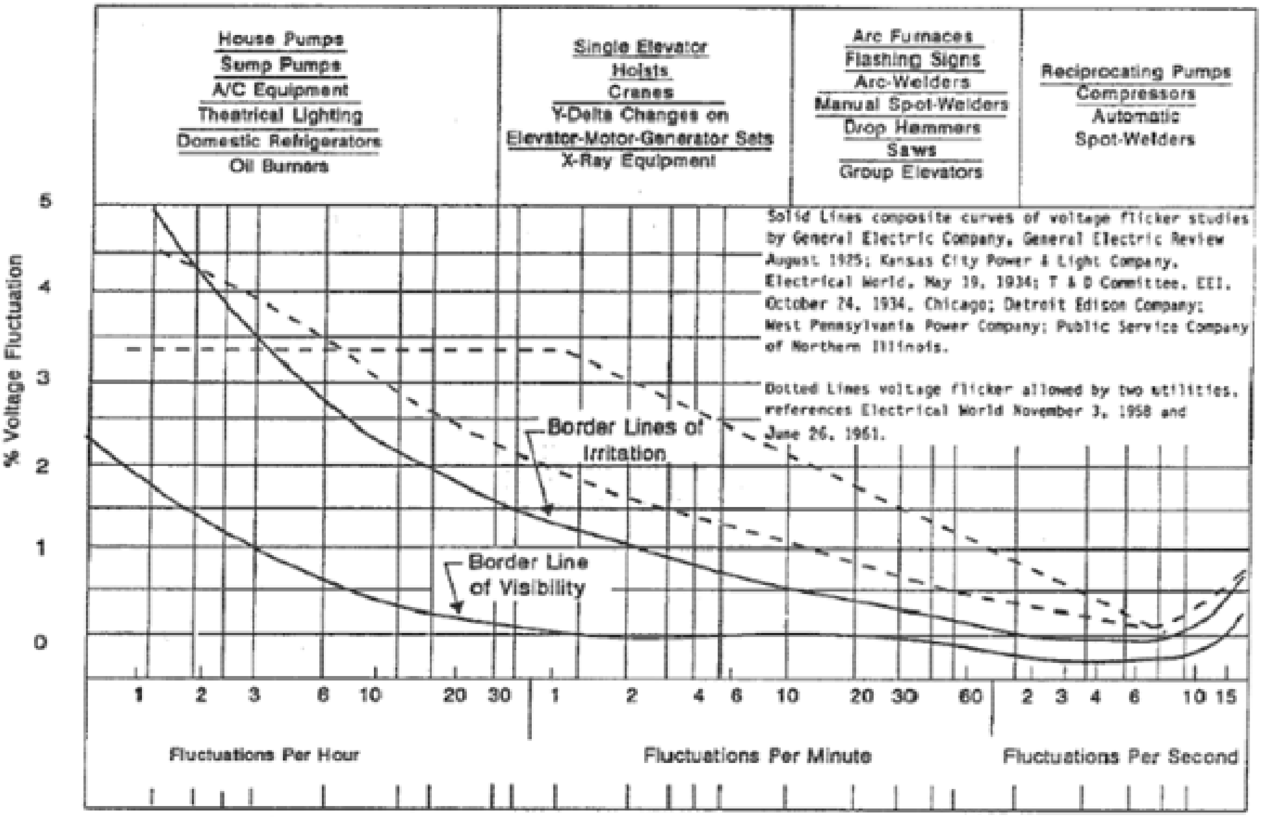

Figure 2 – Allowable Voltage Flicker as per IEEE document 519-1992, Figure 10.3

The voltage fluctuations (flicker) limits are proposed as having to be under the border line of irritation in the above chart. Our own work suggests this can be complied with even for large solar installations due to both the observed rate of solar variation and the ability of solar inverters to manage output reactive power to limit voltage variation (so called 'volt-var' control, which is required for DER plant complying with IEEE 1547:2018 for category B equipment)[3].

2.5 Fault Ride Through (FRT) capability

When a fault happens in a distribution grid, both centralised and distributed generation must be resilient enough to endure sudden changes to voltage and frequency and continue generating throughout this short-term period. If FRT is not set properly, one fault may cause

[3] MEC would need power quality loggers to measure this likely provided via a Technical Assistance package from a development partner.

some generators to disconnect themselves from the grid, cascading the entire power system to a blackout.

Distributed generation and renewable energy generation (viz Distributed Energy Resource; DER) should be specified compliant with the requirements of IEEE 1547:2018. This standard specifies the performance abilities of this equipment. Notable points include:

- A requirement to undertake setpoint changes in 30 seconds or less (noting this could have implications in managing diesel generator minimum loading).
- The DER may not cause a voltage variation when connecting or disconnecting exceeding 3% for medium voltage and 5% for low voltage.
- Two voltage and reactive power control categories are defined; category A and category B. By and large, category A is suitable for behind the meter DER and category B for directly connected DER.
- Section 6 deals with operation under abnormal voltage and frequency conditions on the connected power system. Three categories of performance are described with category 3 being the most tolerant to momentary voltage variance and intended for use in local systems with high DER penetration. Categories I and II only require no-volt ride through up to 150 ms, which may be suitable for the protection of bulk transmission systems (in developed countries) but is not suitable for ride-through in distribution systems with primary protection times generally ranging between 100 and 700 ms.[4] The voltage ride-through requirements for category III are illustrated in Figure 3 below (Figure H.9 of IEEE 1547:2018).

[4] Distribution earth fault protection often includes a definite time delay of up to 0.5 seconds to allow temporary earth faults to self-clear (i.e. momentary tree contacts). Allowing an additional 100ms to this for the circuit breaker open time gives 600ms. Line-to-line and three-phase faults on the feeders usually have primary clearing through inverse-time overcurrent relays. We applied typical feeder protection settings on the Majuro network and considered what typical fault currents, clearing times and pulled-down bus voltages might be expected. We concluded that faults exceeding 1000 amps should clear in under 600ms (=700ms with CB open time added) and that higher impedance faults with lower fault current and longer clearing times would be unlikely to pull the bus voltages on adjacent feeders below 0.5 per unit (giving a longer available ride-through time for category III DER equipment). We therefore set our target primary protection time at < 0.8 seconds giving a 20% margin to the category III equipment zero-voltage ride-through allowance.

Clearly, more detailed network studies would be required to assess particular design proposals and that as renewable energy penetration increases and fault levels decrease, smarter protection schemes may be required including voltage restraint over-current and negative sequence over-current protection elements that allow for faster fault clearing times.

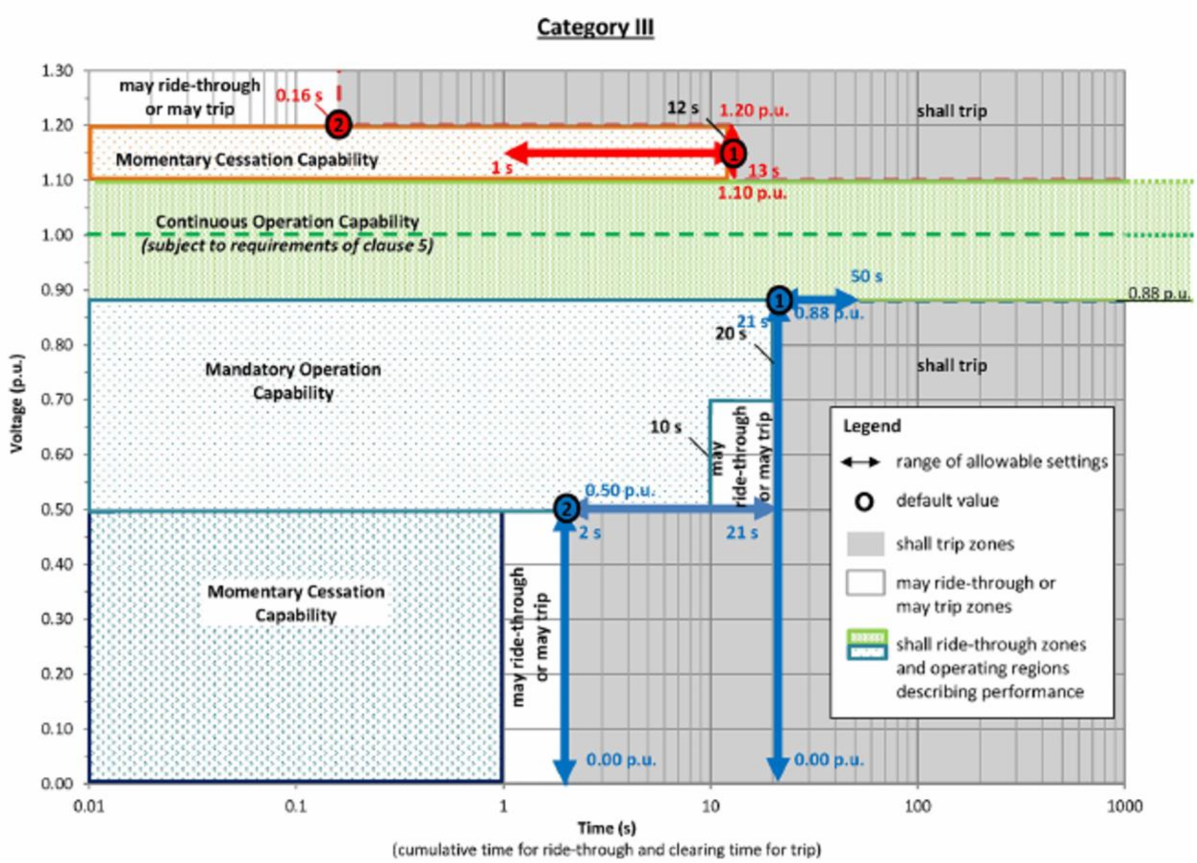

Figure 3 – DER response to abnormal voltages and voltage ride-through requirements for DER of abnormal operating performance Category III

Commercial inverter models able to meet this category III requirement may be limited at present but are expected to increase in time as IEEE1547:2018 becomes more widely adopted. As an example, of all SMA Sunny Tripower inverters (which are widely used across the Pacific region), only the Sunny Tripower Core1 model (floor-mount 50 kW) is noted as having the required firmware upgrade to offer this performance[5].

In order to stay both within this boundary and within the ITIC and ANSI requirements, and with a target primary protection time of less than 0.8 sec (as discussed in the previous footnote), a target voltage envelope for the electricity supply to the customer point of connection is proposed in Table 4.

[5] SMA Tripower Core1 inverter data sheet, http://files.sma.de/dl/29422/STP50-US-40-GridServices-TI-en-10.pdf

Table 4 – Proposed Fault Ride Through Voltage Envelope

Voltage (%)	Time (seconds)
0 < V < 50	0.8
50 < V < 85	0.8 < t ≤ 1
85 < V < 92	1 < t ≤ 10
92 < V < 105	t > 10
105 < V < 110	0.5 < t ≤ 10
110 < V < 120	t ≤ 0.5

This FRT characteristic is also illustrated in Figure 4 below.

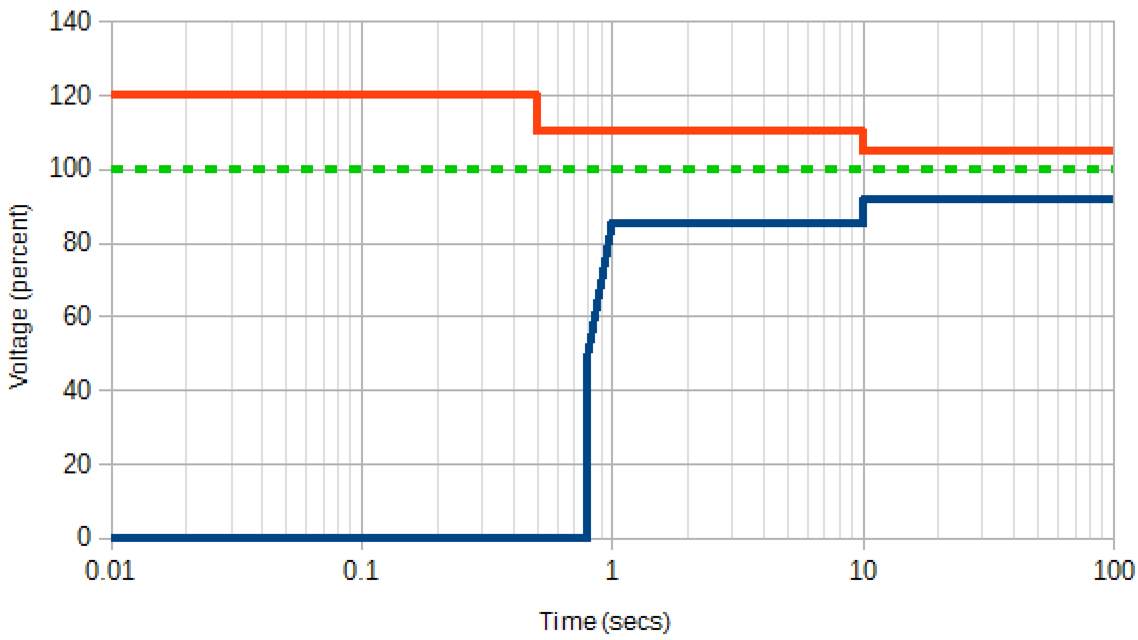

Figure 4 – Voltage Fault Ride Through Service Envelope

2.6 Frequency

Frequency of a power system is one of its basic operating parameters and it is necessary to keep it around its nominal value of 60 Hz, as otherwise it may cause damage to customer's devices, particularly motors that rely on the system frequency to set their speed.

The NEMA appliance requirement (for motors) is +/- 5% of nameplate frequency (60 Hz), which comes to 57 to 63 Hz. For DER ride-through, IEEE 1547 provides the same requirement for frequency disturbance to category I, II and II equipment. This is illustrated in Figure 5.

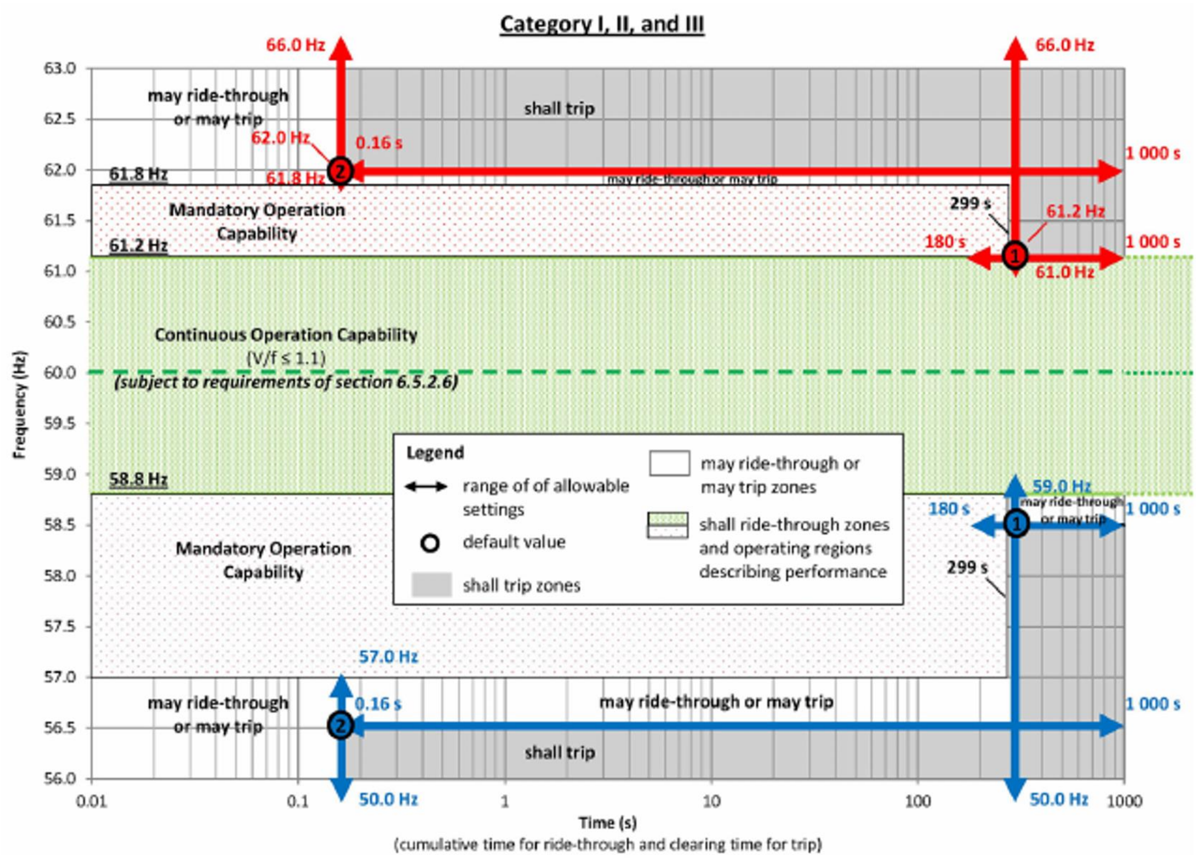

Figure 5 – DER default response to abnormal frequencies and frequency ride-through

Target operation of the power system should remain within this mandatory operating boundary hence our proposed service levels for frequency are:

- nominal: 60 Hz
- allowed variation +/- 1 Hz (59 to 61)
- momentary variance boundary: 57 Hz to 61.8 Hz with target recovery under 10 seconds.

Our suggestion for RMI frequency standard is based on IEEE standard and is summarised in Figure 6.

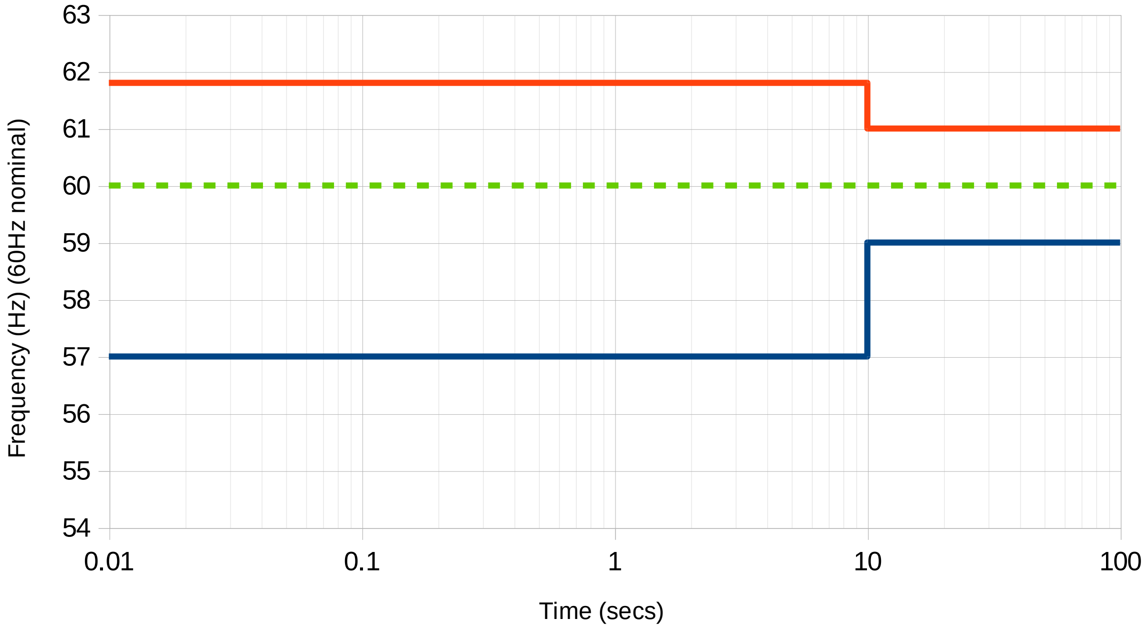

Figure 6 – Frequency Service Envelope

Note that for over-frequency > 62 Hz, the minimum required clearing time is 160 ms. This has implication when net load is lost, and the system is climbing into over-frequency, as it represents a minimum time to shut off inverter generation into the grid.

The standard also requires rate of change of frequency ride-through for category III equipment at 3 Hz/s (averaged over 0.1 sec) and voltage phase angle change (positive sequence voltage) of less or equal to 20 degrees per cycle. Keeping within these requirements defines the rotating inertia and power transfer requirements of the system. We propose setting the system maximum rate of change of frequency and maximum per-cycle voltage angle change at 80 % of these DER category 3 capability requirements.

Note that allowing up to **2.4 Hz/sec** (80 % of 3 Hz/sec) frequency change would, from nominal, exceed our momentary frequency upper boundary in 0.75 seconds. In this regard, the frequency boundary limits may be the stronger limitation. Allowing a high rate of change of frequency does, however, allow options for fast inverter control on power transfer rather than just relying on spinning inertia to limit the rate of frequency change.

To summarise, additional recommended frequency service level requirements are summarised in Table 5.

Table 5 – Proposed Additional Frequency-related Service Level requirements

Requirement	Recommended value
Rate of Change of Frequency (ROCOF)	< 2.4 Hz / s
Voltage phase angle change measured on positive sequence voltage	20 degrees/cycle

2.7 Reliability of Supply

Reliability of supply is measured on the number of power outages and their duration during one calendar year. The less they are, the higher the reliability of supply is.

Reliability is measured in system outage duration indexes in accordance with IEEE 1366:2003. As prescribed by the standard, key reliability of supply measures are:

- SAIDI = system average interruption duration index (the average customers outage minutes per year);
- SAIFI = system average interruption frequency index (the average customer's number of interruptions per year [of outages exceeding 1 minute]); and
- CAIDI = customer average interruption duration index (the average time of an outage exceeding 1 minute)

Key reliability supply measures are related as SAIDI = SAIFI x CAIDI.

A previous report[6] on the Marshall Islands proposed the following parameters for reliability measures:

Table 4 – Reliability measures

	SAIDI (minutes)	SAIFI (number)	CAIDI (minutes)
Grid Standard	250	2	125
Mini-grid Standard	450	3	150
Off-grid Standard	900	6	150

As a comparison, the Pacific Power Association (PPA) publish statistics on their member utilities and this includes SAIDI and SAIFI figures and includes MEC (Majuro). The latest figures published (in 2018 were for year 2016 but included performances for years 2014 and 2015; all as follows:

[6] Feasibility Study - Renewable/Hybrid Microgrid Portfolio, SolarCity, IRENA, Republic of Marshall Islands, 2016.

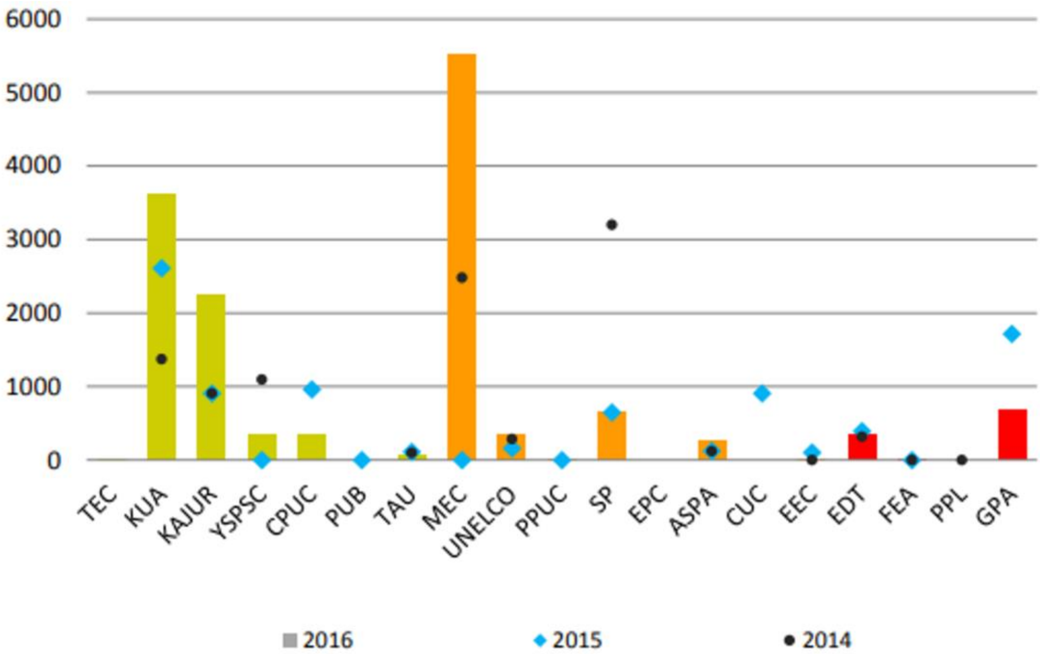

Figure 7 – SAIDI Interruptions (Minutes per Customer) in 2014 – 2016 (zero values shown for MEC in 2015 were due to no data rather than zero SAIDI)

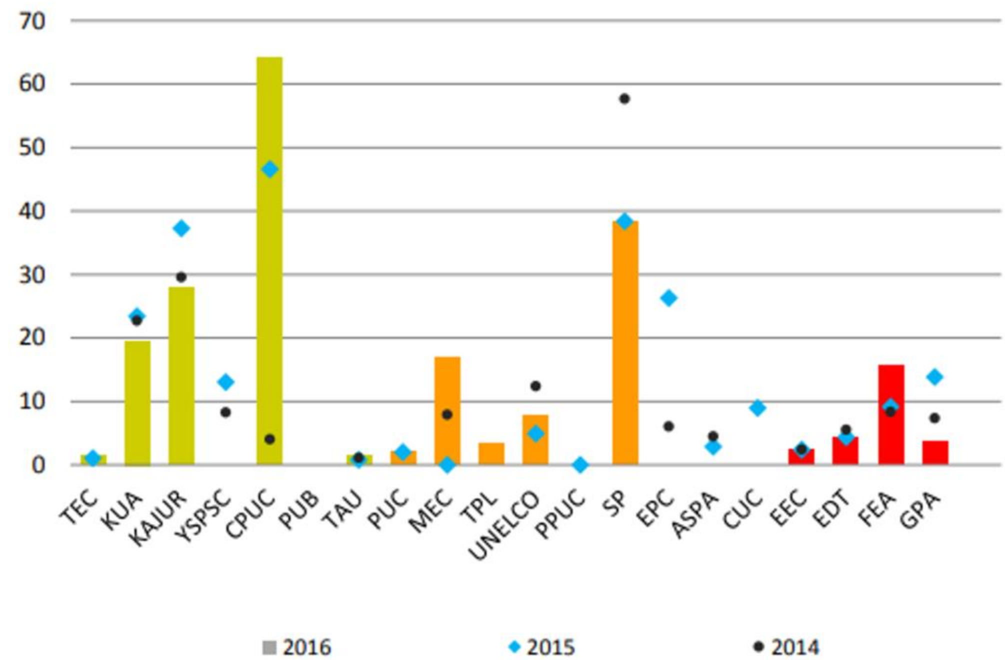

Figure 8 – SAIFI Interruption Frequency (Interruptions per Customer) in 2014 – 2016 (zero values shown for MEC in 2015 were due to no data rather than zero SAIFI)

Based on the SolarCity report, and PPA published statistics, the **proposed SAIDI target** for large island power systems (Mauro and Ebeye) **is 250 minutes**. This is the only metric we propose for RMI power systems. Some outage modelling might be recommended to ensure its appropriateness.

2.8 Protection coordination

In an event of distribution grid faults, protection systems should isolate the fault by disconnecting the affected area only and continue to maintain supply to the rest of the grid. This can only be done if protection systems are properly coordinated. This coordination requires there being sufficient fault current (to blow fuses etc.)

For the Large Islands Grid, we would expect that the feeder level faults are cleared sufficiently quickly that service on the remaining feeders continues. This means ensuring sufficient fault power is connected at all times to operate the primary feeder protection under the target protection time of < 800 ms. Note that this protection time is for our zero-volt ride-through target for connected DER equipment. Longer protection times are possible where the fault is of such high impedance (i.e. at the end of the feeder) that it is unlikely to pull any bus in the adjacent feeders below 0.5 per unit.

Whilst having the capability to continue service upon a single generator fault is desirable, it is not considered practical as a single generator could be holding 50% of the load (or more) at any one time and limiting the frequency transient in this circumstance would be problematic.

For medium (outer island) grids, holding sufficient fault power to manage protection co-ordination on feeder faults requires either over-sizing inverter plant or installing synchronous condensers or always running conventional (diesel or hydro) generation. This is not always practical or economically sound.

We propose that a reasonable target for medium island power systems would be to ensure the majority of customer faults are cleared without losing service to other customers. That is, there is always sufficient fault power on the network to clear the customer service fuse in about 95% of the cases; that is all but the larger customer or commercial customer service fuses. The 95 percent rule would allow 19 of 20 service fuse sizes or MCBs to fall within this criterion and so achieve reasonable reliability.

3 Summary of Service Level Recommendations

#	Requirement description	Requirement	Value	Description
1	**Generation Security**	Number of operational generators needed to cover entire island load	For larger islands: **N-2** For medium Islands: **N-2** For small islands: **N**	For larger and medium size island power systems, there must be enough generation capacity to cover entire power system load in case of failure of two of its largest units.
2	**Distribution Network Security**	Number of operational transformers needed to cover entire island load	For larger islands: at the power station level: **N-1** at the distribution grid level: **N** For medium islands: for all applications: **N** For small islands: **not applicable**	At the power station level, there must be a redundant step-up transformer capable of serving entire power system load. Supply of customers can be done by a single distribution step-down transformer.
3	**Distribution grid protection schemes**	Protection of grid assets at power station/substation – number of required protection relays	For large, medium and small islands: **Single protection relay**	Only one protection relay is needed for protection of distribution assets (feeders, transformers), so redundant (protection B) is not required.
4	**Station batteries (DC) redundancy**	Number of independent, redundant DC batteries for emergency supply of protection and control systems	For larger and medium islands: **Single DC system, two batteries each 50% of the rated capacity of the DC system each, and redundant battery chargers** For small islands: **not applicable**	Batteries supply all essential control and protection devices in a power station and having sufficient and reliable battery power affects power system reliability.
5	**Voltage at a customer connection point**	Voltage limits at a customer connection point	For all island types: **+5% to -8% for all secondary voltages**	Measured voltage at customer's premises

6	**Voltage Flicker**	'Flickering' of lights needs to be reduced to acceptable limits (as per IEEE guideline)	Below the annoyance line as described in Figure 2 above.	Small and short-time variations of voltage affect lighting and produce 'flickering' effect, which should be reduced to acceptable limits.
7	**Fault Ride Through (FRT)**	Voltage limits for transient faults	For large islands: **0 V < V < 50 V 0.8 sec** **50 V < V < 85 V 0.8 < t ≤ 1 sec** **85 V < V < 92 V 1 < t ≤ 10 sec** **92 V < V < 105 V t > 10 sec** **105 V < V < 110 V 0.5 < t ≤ 10 sec** **110 V < V < 120 V t ≤ 0.5 sec** For medium and small islands: **not applicable**	All generators connected to an island grid must stay connected during transient faults for the defined durations.
8	**System Frequency**	Frequency limits	For large islands: **Nominal: 60 Hz** **Variation: ±1 Hz (59 Hz to 61 Hz)** **Short-term variance: 57 Hz to 61.8 Hz, with target recovery under 10 seconds.** For medium[7] and small islands: **Nominal: 60 Hz** **Variation: ±1 Hz (59 Hz to 61 Hz)**	Measured system frequency
9	**Rate of Change of Frequency (ROCOF)**		For large islands: **2.4 Hz/s** For medium and small islands: **not applicable**	

[7] May need further investigation, the danger being the system dropping out with a sudden large load (motor start) coming on the system. Without a frequency and rate of change of frequency standard, this may be challenging to design for

10	**Voltage phase angle change**	Voltage phase angle change measured on positive sequence voltage	For large islands: **20 degrees/cycle** For medium and small islands: **not applicable**	
11	**Reliability of Supply**	System average interruption duration index (SAIDI)	**250 minutes**[8]	Total amount of blackout time during one year (in minutes)
12	**Protection coordination for larger islands**	Operate the primary feeder protection under the target protection time	**Under 800 ms for faults pulling adjacent feeder bus voltages below 0.5 pu.**	
13	**Protection coordination for medium and small islands**	Sufficient fault power on the network to clear the customer service fuse	**95 % of the time**	

[8] Possibly to only apply to Majuro and Ebeye