Technical Report

Assessment of Increased Risks Imposed by a Relaxation of Loss-Of-Mains Protection Settings Applied to Generation Connected to the Electricity Network in Northern Ireland (WP1 and WP2)

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1 Introduction

This document reports on the outcomes of the project “Assessment of Increased Risks Imposed by a Relaxation of Loss-Of-Mains Protection Settings Applied to Generation Connected to the Electricity Network in Northern Ireland”.

The report covers the following two work packages:

1. WP1 – Analysis of the DG connection registers to establish dominant generating technologies and generation mixes in the identified islanding scenarios.
2. WP2 – Investigation of the LOM protection stability under critical system events (defined by NIE Networks).

The following sections describe in detail the available data, the analysis undertaken to date, key observations and recommendations for the subsequent work packages WP3 and WP4.

The overall flowchart illustrating the dependencies of various work packages and tasks in the project are illustrated in Figure 1. Work packages described in this report specifically are marked in green.

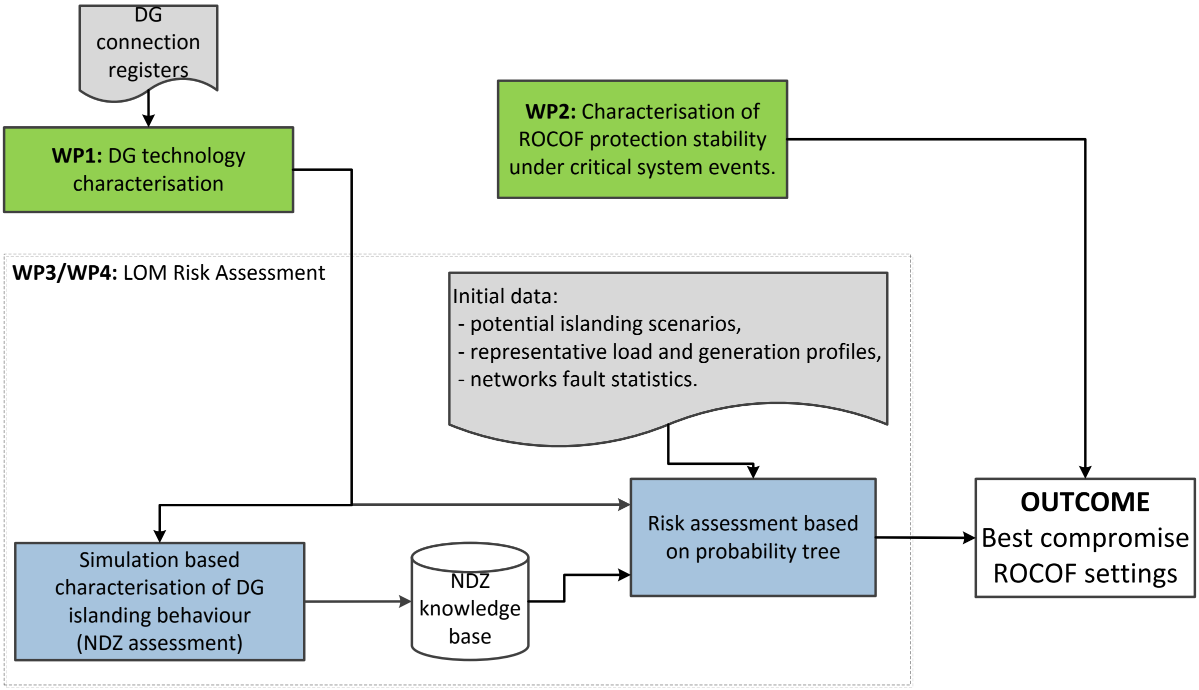


Figure 1. Project work packages and tasks

2 WP1 – Analysis of the DG connection registers

2.1 Key objectives and available data

In this work package, detailed analysis of the existing NIE Networks DG registers[1,2] has been performed. The aim was to identify the predominant groups (generation mixes) which could potentially become islanded, and the distribution of the generation capacity within such groups according to four distinct islanding scenarios defined as:

- **Scenario 1**: Isolation of a BSP;
- **Scenario 2**: Loss of an individual 33 kV feeder;
- **Scenario 3**: Loss of supply to a primary substation;
- **Scenario 4**: Loss of an individual HV (11 kV) feeder.

A detailed register of all existing distributed generators[1] at a specific point in time was made available by NIE Networks. According to the register, there were 10,690 individual connections across the entire network with a total installed capacity of 896.2 MW.

Additionally, a register of the already-contracted (but still not connected) generation[2] was provided, together with solar and on-shore wind capacity forecasts to aid the assessment of future ROCOF protection risks.

The results presented in the next section are obtained for two sets of data, i.e. for the existing DG population (referred to as Register 1), and for the combined DG set including both connected and contracted (but not yet connected) generation (referred to as Register 2).

The outcomes of this work package will feed directly into WP3 and WP4 where DG distribution histograms will be used to obtain the overall risk figures related to the considered optional adjustments to the ROCOF protection settings. The suggested setting values are included in Table 8 in the summary section 4.

2.2 Generation grouping in islanding scenarios 1-4

Initially, a summary of DG capacity, the number of connections, and the number of potential islanding points have been derived from Registers 1 and 2. The contracted generation (as a difference between Register 2 and 1) is also included. The summary is presented in Table 1 and Table 2 for Large Scale Generators (LSG) and Small Scale Generators (SSG) respectively. Additionally, an observed percentage increase of each quantity (between Register 1 and Register 2) has been calculated. In particular, an increase in the number of potential islanding points gives an indication of the growth of the overall risk of undetected islanding operation. It can be observed that the number of islanding points grows at a much slower rate compared to the growth of capacity and/or number of generators. This is particularly true for SSG. Due to the existing high penetration level of small generators, many new generators are being connected in the vicinity of the exiting generators, and therefore, do not form additional potential islanding points.

[1] File *all_generation_data.xlsx* made available by NIE Networks – last accessed 12 October 2015
[2] File *Generator Register_committed to connect 03_02_16.xlsx* – last accessed 5 January 2016

Table 1. DG register summary for large generators >5MW (Phase 1)

Generation set	Installed capacity [MW]	Number of generators	Number of islanding points (combined scenarios 1 and 2)
Register 1 (connected)	623.2	38	30
Register 2 (connected + contracted)	999.6	64	41
Contracted only	376.4	26	N/A
Relative increase between Register 1 and Register 2 [%]	60.4	68.4	36.7

Table 2. DG register for small generators <5MW (Phase 2)

Generation set	Installed capacity [MW]	Number of generators	Number of islanding points (combined scenarios 3 and 4)
Register 1 (connected)	273.0	10652	1291
Register 2 (connected + contracted)	366.3	11064	1317
Contracted only	93.2	412	N/A
Percentage increase between Register 1 and Register 2 [%]	34.2	3.9	2.0

Subsequently, all generation types included in the available registers were mapped into four generating technologies as outlined in Table 3. These four technologies can potentially form 15 different generation mixes including: 4 single technology islands, 6 groups of 2, 4 groups of 3, and 1 group including all 4 technologies. The registers were then analysed individually to determine the population of each type of island. The results of this analysis are presented in Figure 2 (islanding scenario 1), Figure 4 (islanding scenario 2), Figure 6 (islanding scenario 3) and Figure 8 (islanding scenario 4).

Additionally, a distribution of the installed capacity for all existing types of islands has been obtained and is presented as a histogram in Figure 3 (islanding scenario 1), Figure 5 (islanding scenario 2), Figure 7 (islanding scenario 3) and Figure 9 (islanding scenario 4).

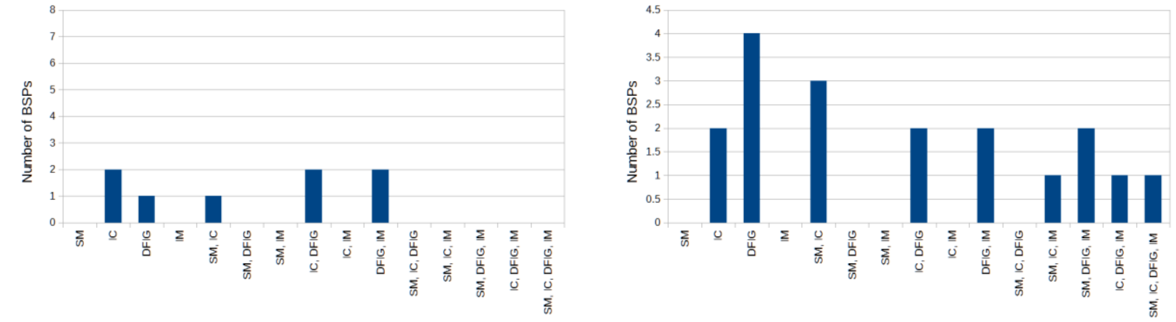
Table 3. Generation technology mapping

Generation technologies reported in the register	Assumed generator type
Anaerobic Biogas CHP Diesel Hydro	Synchronous Machine (denoted in figures and tables as SM)
PV Tidal Wind (Fully rated converter)	Inverter Connected (denoted in figures and tables as IC)
Wind (DFIG)	DFIG
Biomass & Energy Crops (not CHP) Wind (Induction machine)	Induction Machine (denoted in figures and tables as IM)

These histograms will be subsequently used in an LOM protection risk assessment exercise that will be carried out in WP3 (Scenarios 1 and 2) and WP4 (Scenarios 3 and 4). A similar approach has been taken in previous risk assessment work for the GB system [1][2].

Group	No of BSPs	Percentage
SM	0	0.0
IC	2	25.0
DFIG	1	12.5
IM	0	0.0
SM, IC	1	12.5
SM, DFIG	0	0.0
SM, IM	0	0.0
IC, DFIG	2	25.0
IC, IM	0	0.0
DFIG, IM	2	25.0
SM, IC, DFIG	0	0.0
SM, IC, IM	0	0.0
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**8**	**100.0**

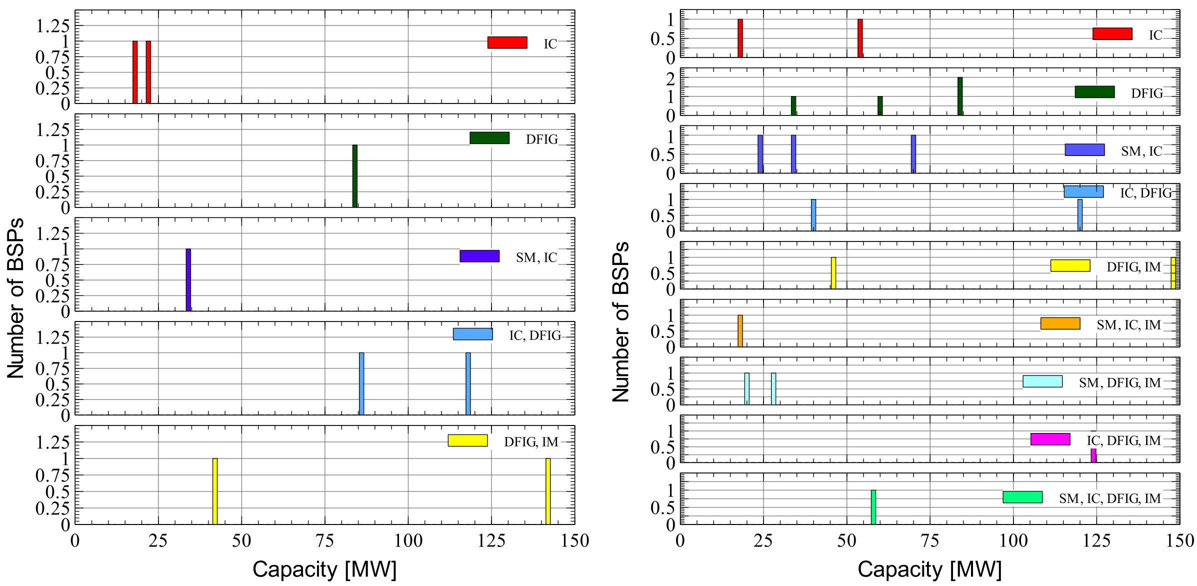
Group	No of BSPs	Percentage
SM	0	0.0
IC	2	11.1
DFIG	4	22.2
IM	0	0.0
SM, IC	3	16.7
SM, DFIG	0	0.0
SM, IM	0	0.0
IC, DFIG	2	11.1
IC, IM	0	0.0
DFIG, IM	2	11.1
SM, IC, DFIG	0	0.0
SM, IC, IM	1	5.6
SM, DFIG, IM	2	11.1
IC, DFIG, IM	1	5.6
SM, IC, DFIG, IM	1	5.6
Total:	**18**	**100.0**



a) Register 1 – connected DG

b) Register 2 – connected + contracted DG

Figure 2. Islanding groups in Scenario 1



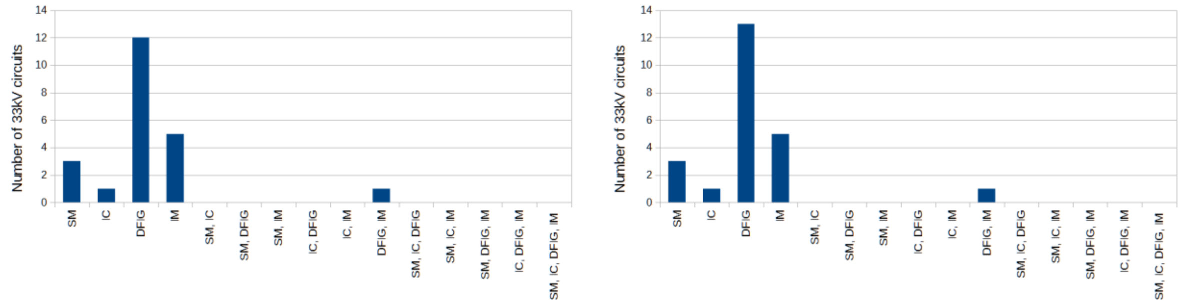
a) Register 1 – connected DG

b) Register 2 – connected + contracted DG

Figure 3. Histogram representing size distribution of dominant generation mixes in Scenario 1

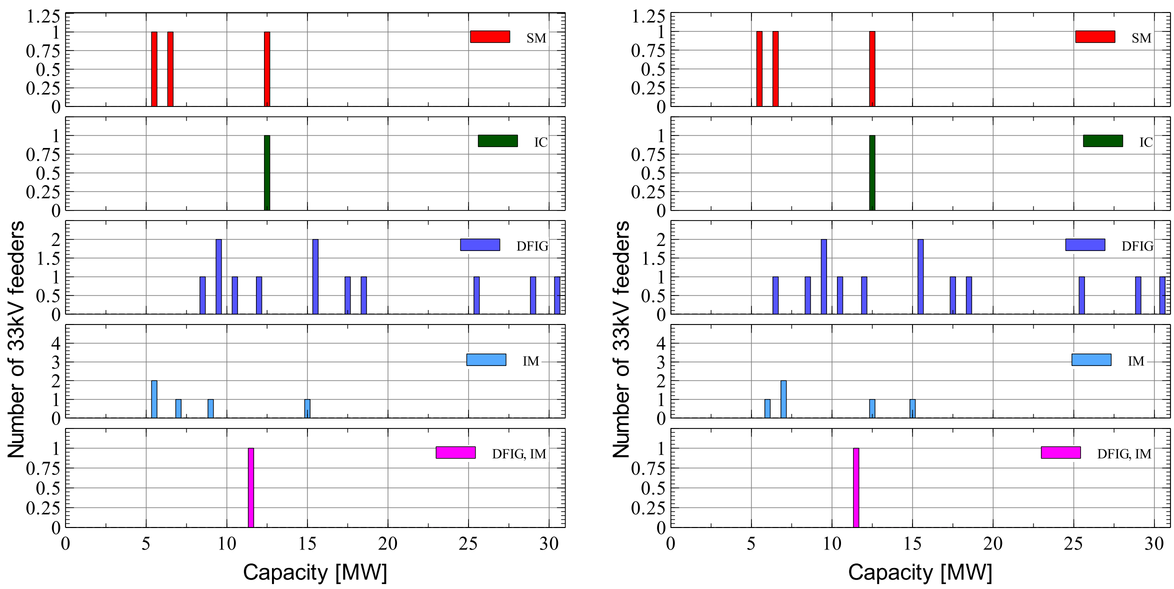
Group	33 kV feeders or primaries	Percentage
SM	3	13.6
IC	1	4.5
DFIG	12	54.5
IM	5	22.7
SM, IC	0	0.0
SM, DFIG	0	0.0
SM, IM	0	0.0
IC, DFIG	0	0.0
IC, IM	0	0.0
DFIG, IM	1	4.5
SM, IC, DFIG	0	0.0
SM, IC, IM	0	0.0
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**22**	**100.0**

Group	33 kV feeders or primaries	Percentage
SM	3	13.0
IC	1	4.3
DFIG	13	56.5
IM	5	21.7
SM, IC	0	0.0
SM, DFIG	0	0.0
SM, IM	0	0.0
IC, DFIG	0	0.0
IC, IM	0	0.0
DFIG, IM	1	4.3
SM, IC, DFIG	0	0.0
SM, IC, IM	0	0.0
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**23**	**100.0**



a) Register 1 – connected DG b) Register 2 – connected + contracted DG

Figure 4. Islanding groups in Scenario 2

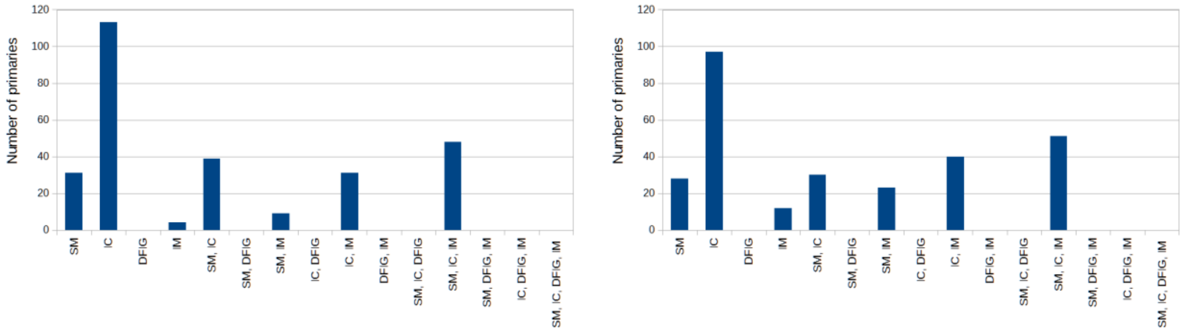


a) Register 1 – connected DG b) Register 2 – connected + contracted DG

Figure 5. Histogram representing size distribution of dominant generation mixes in Scenario 2

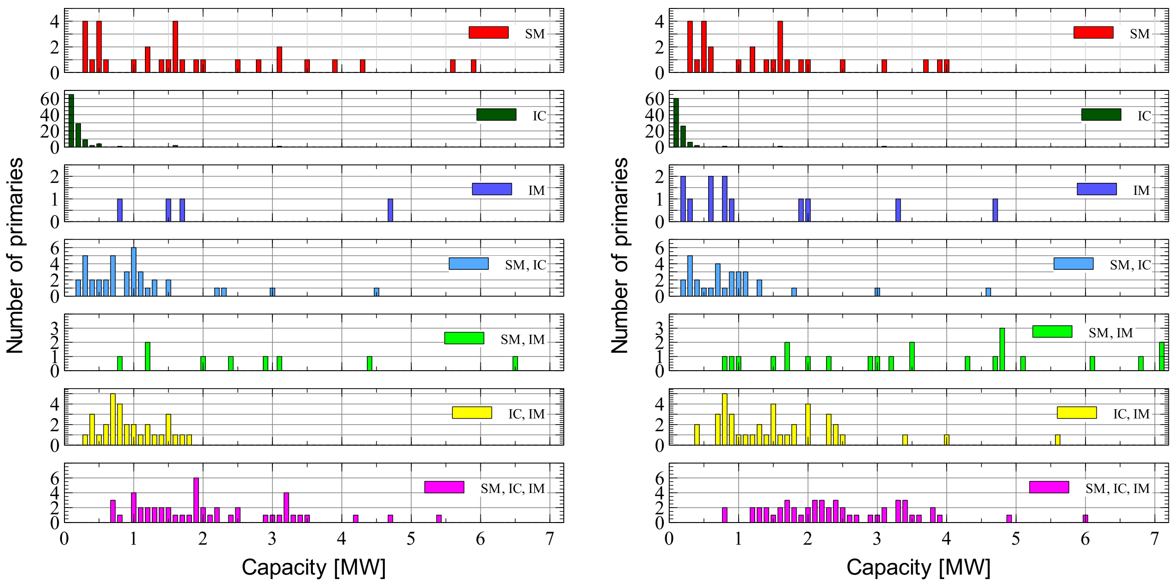
Group	Primaries	Percentage
SM	31	11.3
IC	113	41.1
DFIG	0	0.0
IM	4	1.5
SM, IC	39	14.2
SM, DFIG	0	0.0
SM, IM	9	3.3
IC, DFIG	0	0.0
IC, IM	31	11.3
DFIG, IM	0	0.0
SM, IC, DFIG	0	0.0
SM, IC, IM	48	17.5
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**275**	**100.0**

Group	Primaries	Percentage
SM	28	10.0
IC	97	34.5
DFIG	0	0.0
IM	12	4.3
SM, IC	30	10.7
SM, DFIG	0	0.0
SM, IM	23	8.2
IC, DFIG	0	0.0
IC, IM	40	14.2
DFIG, IM	0	0.0
SM, IC, DFIG	0	0.0
SM, IC, IM	51	18.1
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**281**	**100.0**



a) Register 1 – connected DG b) Register 2 – connected + contracted DG

Figure 6. Islanding groups in Scenario 3

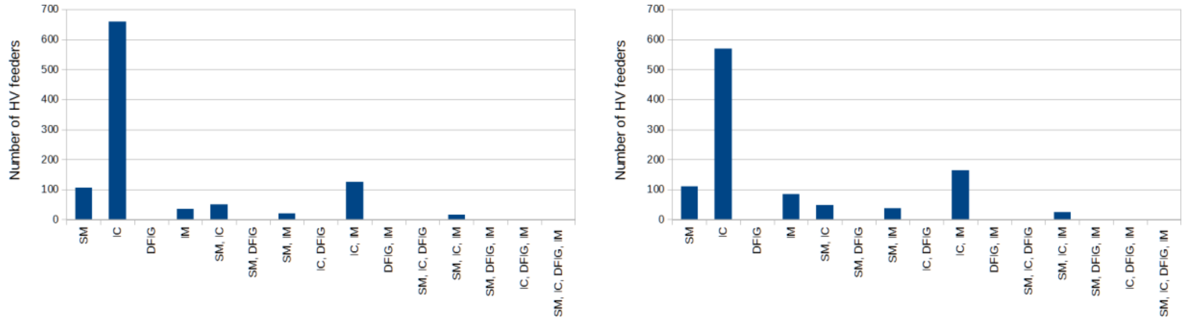


a) Register 1 – connected DG b) Register 2 – connected + contracted DG

Figure 7. Histogram representing size distribution of dominant generation mixes in Scenario 3

Group	HV Feeders	Percentage
SM	107	10.5
IC	659	64.9
DFIG	0	0.0
IM	36	3.5
SM, IC	51	5.0
SM, DFIG	0	0.0
SM, IM	21	2.1
IC, DFIG	0	0.0
IC, IM	125	12.3
DFIG, IM	0	0.0
SM, IC, DFIG	0	0.0
SM, IC, IM	17	1.7
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**1016**	**100.0**

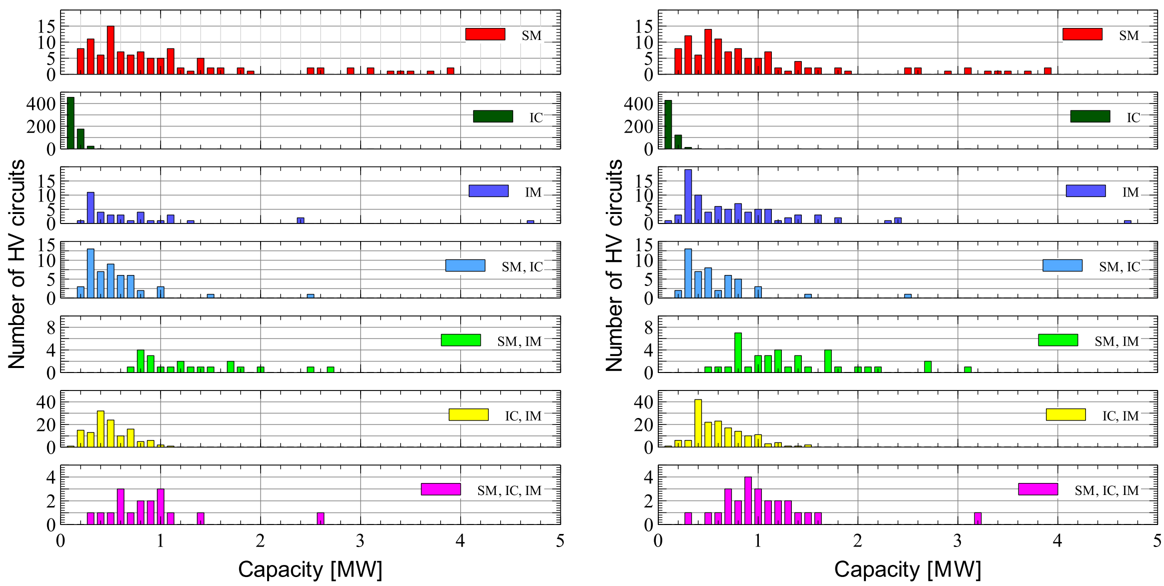
Group	HV Feeders	Percentage
SM	110	10.6
IC	569	54.9
DFIG	0	0.0
IM	84	8.1
SM, IC	48	4.6
SM, DFIG	0	0.0
SM, IM	37	3.6
IC, DFIG	0	0.0
IC, IM	163	15.7
DFIG, IM	0	0.0
SM, IC, DFIG	0	0.0
SM, IC, IM	25	2.4
SM, DFIG, IM	0	0.0
IC, DFIG, IM	0	0.0
SM, IC, DFIG, IM	0	0.0
Total:	**1036**	**100.0**



a) Register 1 – connected DG

b) Register 2 – connected + contracted DG

Figure 8. Islanding groups in Scenario 4



a) Register 1 – connected DG

b) Register 2 – connected + contracted DG

Figure 9. Histogram representing size distribution of dominant generation mixes in Scenario 4

3 WP2 – Investigation of the LOM protection stability

In this work package, an investigation has been undertaken to establish possible ROCOF, Voltage Vector Shift (VS), frequency and voltage relay settings which would ensure stability of the LOM protection. In particular, the worst case scenario system-wide frequency profiles have been used to test stability of the ROCOF, VS and frequency protection, while voltage ride through characteristics have been used to verify under-voltage protection settings.

A number of records (corresponding to various critical system incidents) obtained from dynamic simulations were provided by NIE Networks. A short summary of the available records is included in Table 4.

Table 4. Summary of simulated records of major system events

Event No	Short description
Event 1	Frequency Drop without Fault
Event 2	Frequency Drop with Fault
Event 3	Frequency Drop with Fault 100ms, 50% retained voltage
Event 4	Frequency Drop with Fault 100ms, 5% retained voltage
Event 5	Frequency Rise without Fault
Event 6	Frequency Rise with Fault
Event 7	Frequency Rise with Fault 100ms, 50% retained voltage
Event 8	Frequency Rise with Fault 100ms, 5% retained voltage
Event 9	Loss of Largest Infeed High RoCoF Scenario
Event 10	Loss of Largest Outfeed Typical Scenario
Event 11	Loss of Largest Infeed Typical Scenario
Event 12	NI High Frequency with Fault 100ms, 50% retained voltage
Event 13	NI High Frequency with Fault 100ms, 5% retained voltage
Event 14	NI Low Frequency with Fault 100ms, 50% retained voltage
Event 15	NI Low Frequency with Fault 100ms, 5% retained voltage

These critical profiles were provided by NIE Networks in digital form (CSV or COMTRADE format) as three phase voltage waveforms sampled at 10 kHz, suitable as an input to a dynamic relay model or hardware injection into a physical device.

Moreover, a few faults records (captured during actual network incidents) were provided which gave an additional realistic insight into the LOM protection performance in the vicinity of a fault. A summary of the utilised records is presented in Table 5.

Table 5. Summary of fault records of actual incidents

Event No	Short description	Voltage level	Date
Record 1	Line fault (3-phase), downstream partial loss of load	110 kV	05/07/2015
Record 2	Voltage dip (3-phase)	220 kV	08/10/2014
Record 3	Voltage dip (3-phase)	110 kV	29/01/2015
Record 4	Line disconnected - no fault detected	220 kV	14/03/2015
Record 5	Unclassified	220 kV	29/01/2016

3.1 Stability of ROCOF protection

Due to the high number of tests to be performed, the majority of the results were obtained using a validated ROCOF relay model available at Strathclyde [3]. However, the stability assessment was also supplemented by hardware injection-based validation using a smaller number of selected case studies.

3.1.1 Simulated system events

In the first step, each simulated record (Events 1 to 15) was repeatedly processed by the relay model at different time delay settings. At each time delay the ROCOF setting of the relay was gradually increased from a small value to a point where the relay no longer operated. Accordingly, this experimental method was used to establish the minimum stability settings. The results are presented graphically in Figure 10. For illustrative purposes, an example relay model response to Event 15 is presented in Figure 11.

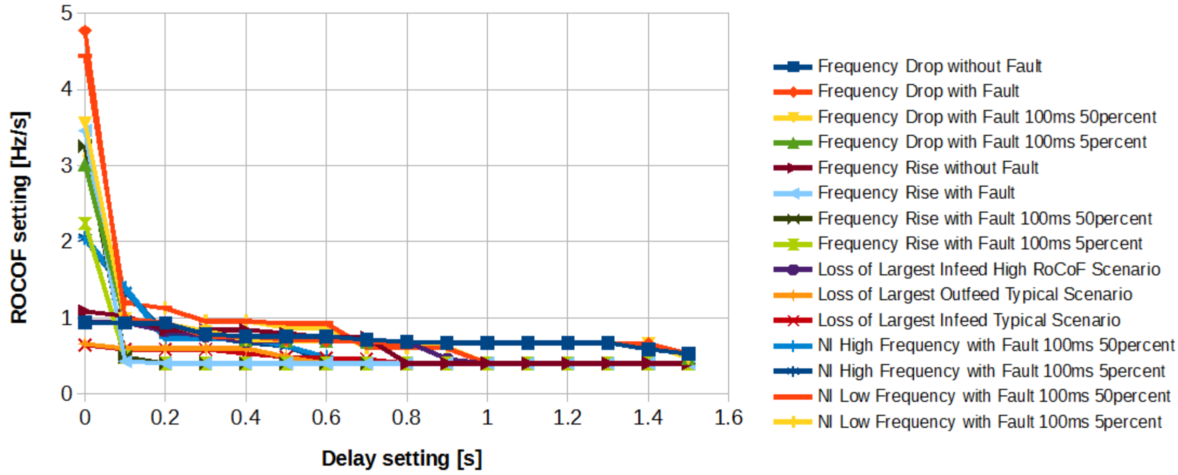
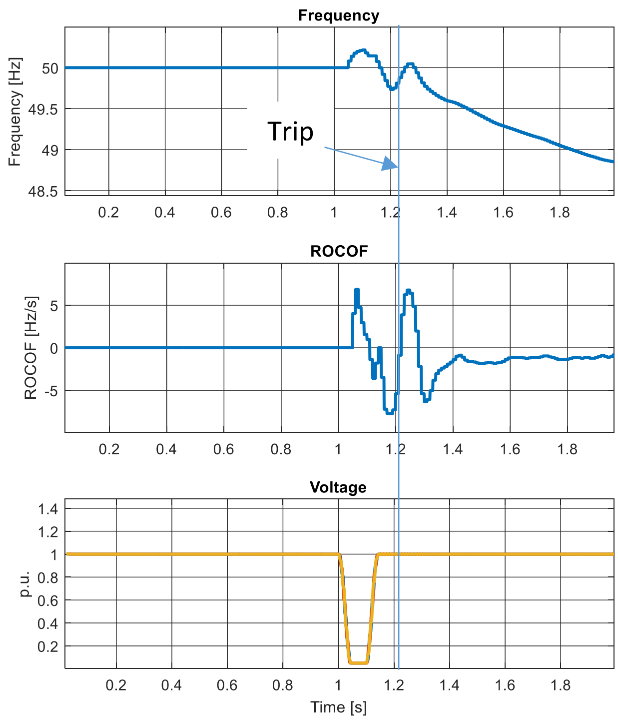


Figure 10. Minimum ROCOF settings to ensure stability (simulated events)



	Status	Trip time [s]
Under-Voltage	0	99
Over-Voltage	0	99
Under-Frequency	0	99
Over-Frequency	0	99
ROCOF	1	0.2115
Vector Shift	0	99
Relay Output	1	0.2115

Figure 11. ROCOF relay model response to Event 15 (setting 2 Hz/s, no time delay)

To verify these results, three events with the highest stability setting values were selected for laboratory hardware testing using the same methodology but with an actual relay device (Micom P341). The outcome of this validation has been recorded in Table 6 together with the setting difference between the model and the relay (expressed in Hz/s). The highest recorded mismatch in the ROCOF settings, established using the simulated versus the actual relay device, was 0.27 Hz/s (as shown in red in the table). The average mismatch was only 0.14 Hz/s. It is also worth noting that a high level of inconsistency was observed during injection testing with a zero time delay setting. The actual relay device, on some occasions, would remain stable at a 1 Hz/s setting while at other times it would trip at values above 2 Hz/s, for the same tests. For this reason, the hardware testing results without using time delay are not included in this report. It was found that this inconsistent behaviour ceases when a short time delay is applied, e.g. 200ms. Although the exact nature of this behaviour is not known, it is most likely to be associated with the presence of the fault causing a voltage dip at the beginning of the islanding event.

Table 6. Hardware verification of the ROCOF model results

Time Delay [ms]	Event 3 Min setting [Hz/s]		Error [Hz/s]	Event 13 Min setting [Hz/s]		Error [Hz/s]	Event 15 Min setting [Hz/s]		Error [Hz/s]
	Relay model	MiCOM Relay		Relay model	MiCOM Relay		Relay model	MiCOM relay	
100	0.98	1.05	**0.07**	1.39	1.53	**0.14**	1.2	1.45	**0.25**
200	0.94	0.96	**0.02**	0.73	1.0	**0.27**	1.13	1.36	**0.23**
300	0.76	0.95	**0.19**	0.73	0.99	**0.26**	0.96	1.2	**0.24**
500	0.71	0.76	**0.05**	0.62	0.8	**0.18**	0.93	1.09	**0.16**
800	0.68	0.73	**0.05**	0.4	0.6	**0.2**	0.61	0.67	**0.06**
1000	0.67	0.71	**0.04**	0.4	0.41	**0.01**	0.4	0.5	**0.1**

In order to establish the best possible options for ROCOF relay settings, the highest values (across all 15 events) were recorded as a single characteristic and recorded in Figure 12 as “Relay model”. In the same figure, the highest values from the physical hardware testing are also represented (marked as “Hardware relay”) together with the existing recommended setting of 0.4 Hz/s, and four proposed alternative setting recommendations which would ensure stability under all given critical event scenarios. These four alternative settings are suggested for the subsequent risk assessment, where the lowest risk option will be recommended as the optimal setting (refer also to Table 8 in the summary section of this report).

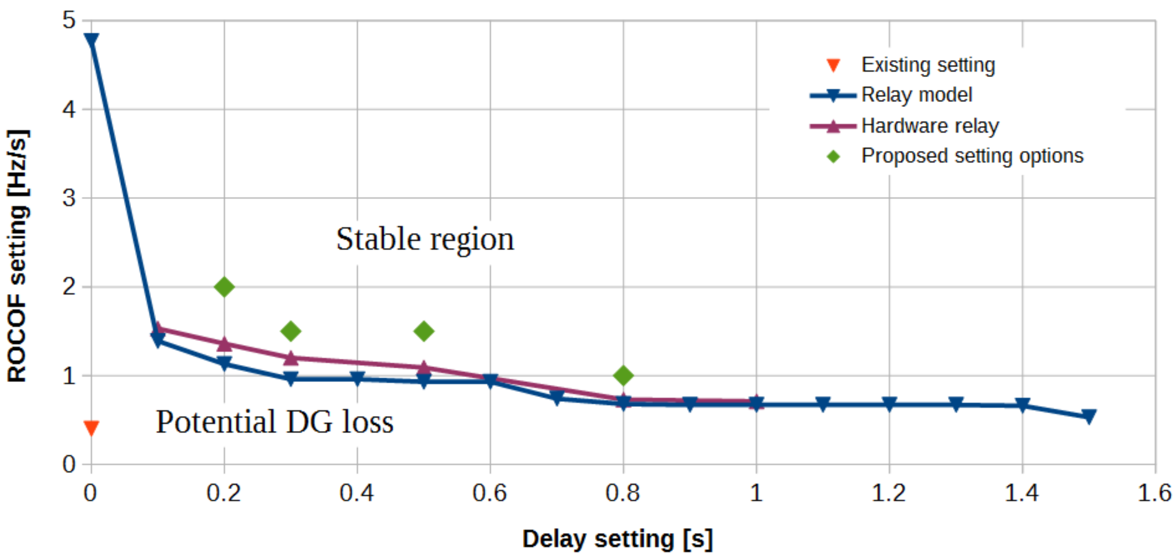


Figure 12. Proposed ROCOF setting options mapped against established stability settings (simulated events)

3.1.2 Actual fault records

To provide additional level of confidence regarding the ROCOF stability limits and proposed setting options established in section 3.1.1, five available transmission system fault records (refer to Table 5) were assessed in a similar way, using ROCOF relay model, and further verified by hardware injection. Hardware injection in this case was applied to record 3, which from the model based simulations, indicated the highest ROCOF setting values. The model based results are presented in Figure 13, whereas the comparison of the highest model based ROCOF values (across all fault records) with hardware injection results based on record 3, are included in Figure 14. It can be seen that there is a good correspondence between the relay model and hardware injection, as well as, that there is a comfortable margin of stability between the proposed setting options and minimum required ROCOF settings established from the available actual fault records.

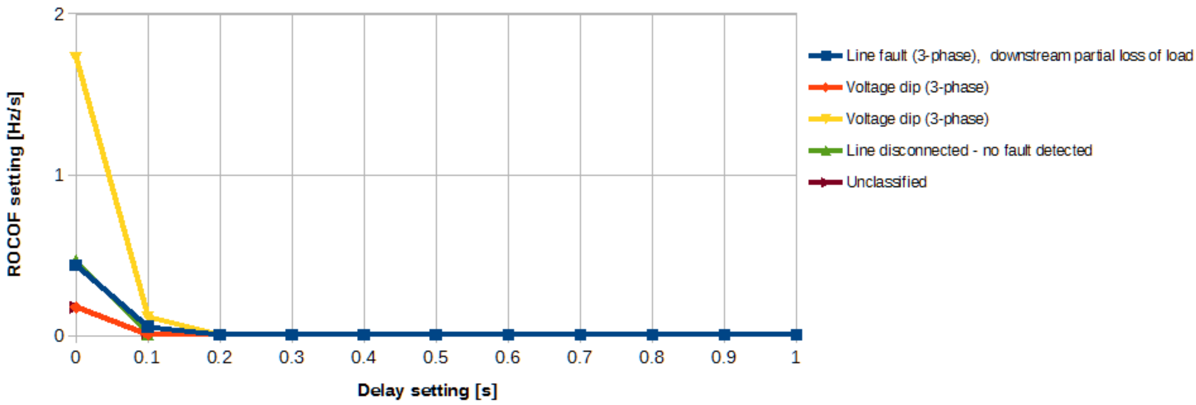


Figure 13. Minimum ROCOF settings to ensure stability obtained from relay model (actual fault records)

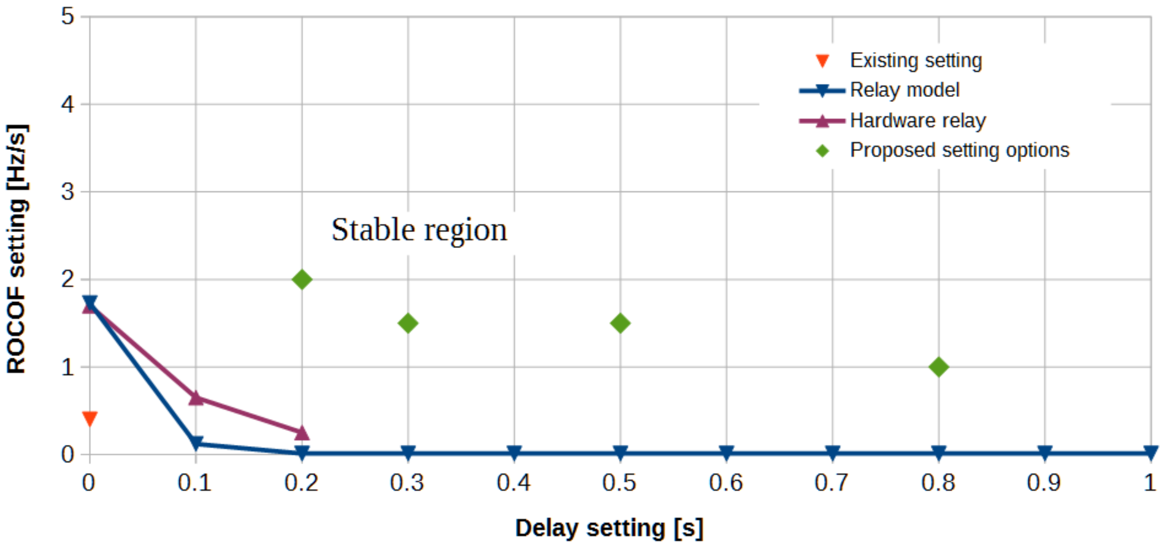


Figure 14. Proposed ROCOF setting options mapped against stability settings obtained from actual system faults

3.2 Stability of Vector Shift protection

3.2.1 Simulated system events

The same 15 critical events used in the studies discussed earlier in this report (see Table 4) were processed by the Vector Shift protection model and injected into the same Micom P341 relay as used previously with the VS module enabled. The minimum angle setting values to ensure relay stability are presented in Figure 15. These low values are impossible to verify using the Micom relay, as the lowest available setting is 2°. Nevertheless, all records have been injected in to the relay using the lowest setting (2°) which resulted in tripping in response to one of the records only (refer to Table 7). The relay reported a voltage vector shift of 2.6° and did not trip when the setting was changed to 3°. It can be concluded that this is evidence of a relatively high level of VS protection stability. When considering critical system wide events there seems to be no reason for recommending any values greater than 6°.

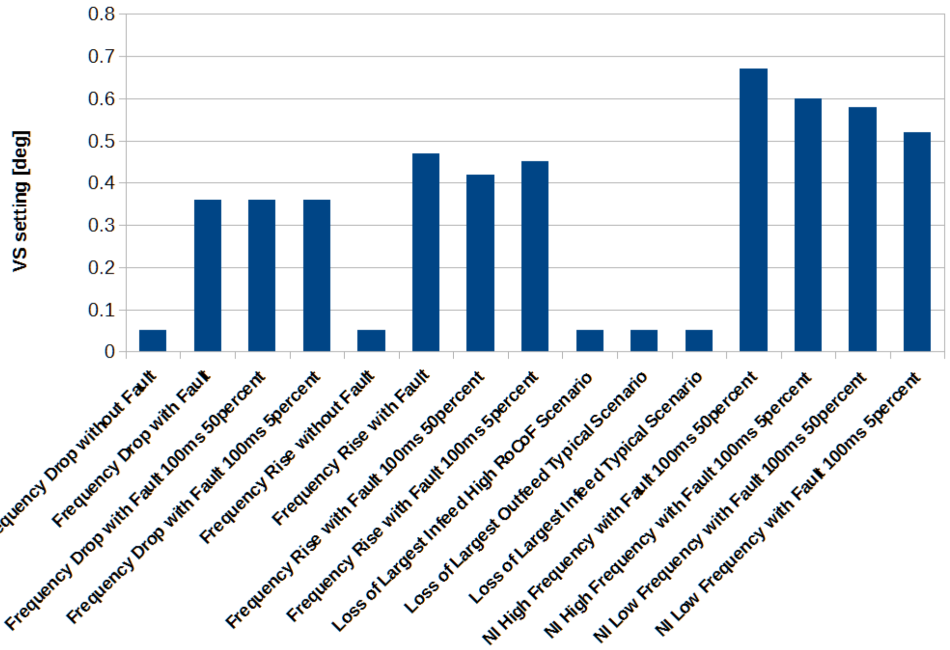


Figure 15. Vector Shift minimum settings to ensure LOM protection stability under simulated system events (VS Relay Model)

Table 7. Hardware test results for voltage vector shift relay (Micom P341)

Event 1	Event 2	Event 3	Event 4	Event 5	Event 6	Event 7	Event 8	Event 9	Event 10	Event 11	Event 12	Event 13	Event 14	Event 15
No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	No Trip	Trip 2.6 °	No Trip	No Trip	No Trip

3.2.2 Actual fault records

To further investigate the high stability levels of VS protection, the available fault records (as summarised in Table 5), were used. Due to past experience of spurious tripping of a number of VS relays during storm conditions in Ireland, it was important to verify whether such spurious tripping could have been initiated by transmission system faults. The minimum VS stability settings based on the five available records are presented in Figure 16, both obtained from the relay model and from hardware injection. These results clearly demonstrate that the VS tripping at the current recommended setting of 6° is very much possible during transmission system faults. On some occasions relay operation can be expected with settings up to 12°. However, it is understood that VS relay spurious tripping under transmission system faults does not have the same system-wide effect as frequency swings can have on ROCOF protection, and therefore, are less threatening to transmission system stability. Nevertheless, it is considered important to explore the risk of possible increase in VS setting to improve security. Thus, two setting options of 6° and 12° will be considered in further work (WP3 and WP4).

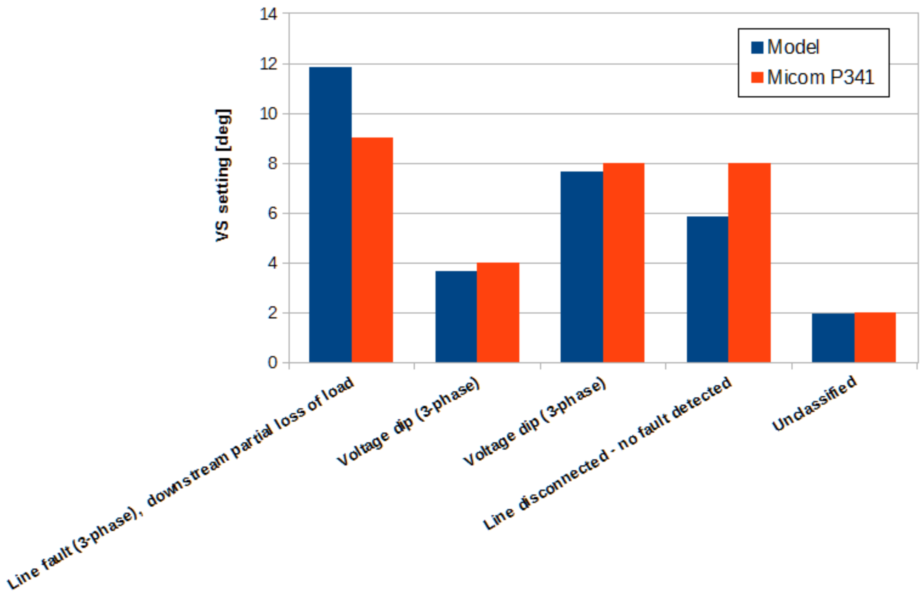


Figure 16. Vector Shift minimum settings to ensure LOM protection stability under actual fault records

3.3 Stability of over-frequency protection

The proposed adjustment to the over-frequency setting of DG interface protection has been investigated by executing the voltage relay model simulations with the 15 available critical system events (refer to Table 4). The results are presented in Figure 17 for both the existing setting of 50.5 Hz and the proposed modification to the setting of 52 Hz with 1 s delay. It can be clearly seen that the proposed change can successfully stabilise over-frequency G59 protection under all considered critical events.

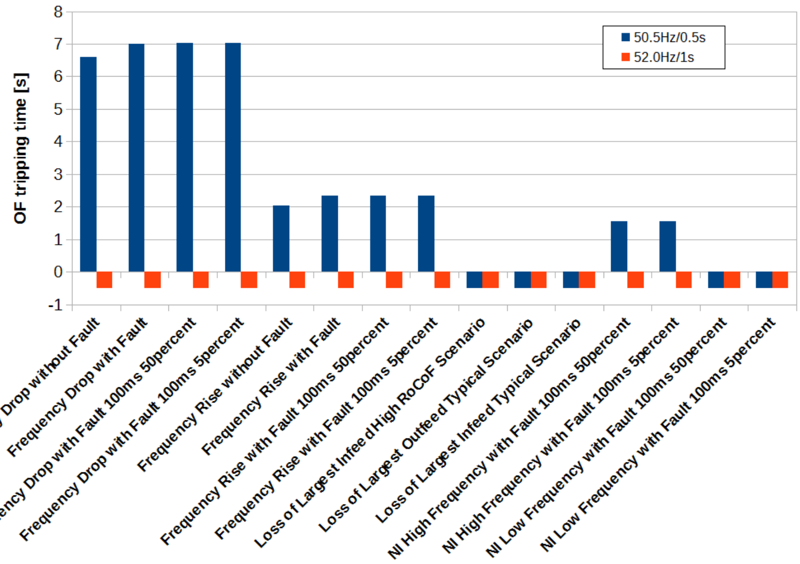


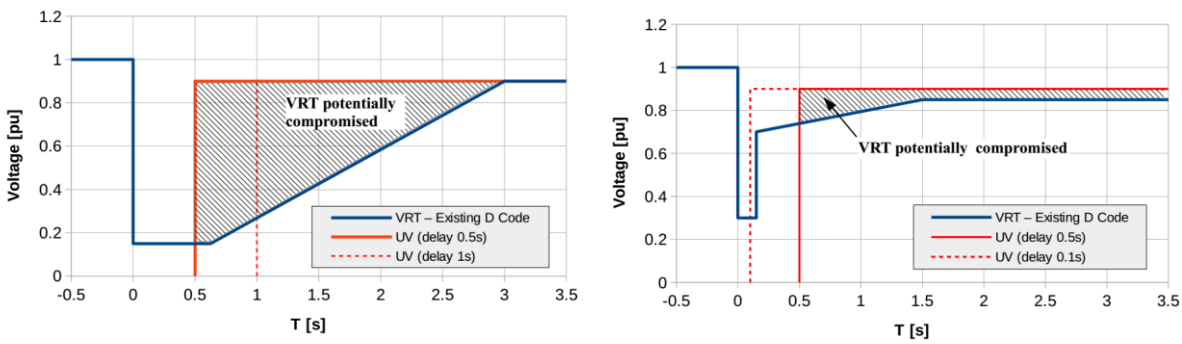
Figure 17. Operation of the over-frequency protection under 15 simulated events

3.4 Revision of under-voltage protection settings

The NIE Networks Distribution Code [4] specifies voltage ride through (VRT) requirements for generation connected to the distribution system. This is illustrated in Figure 18a and Figure 18b for large scale (>5MW) and small scale (<5MW) generation respectively. Additionally, the existing UV settings are superimposed on the VRT characteristics. The solid red line is the current G59 recommended setting while the dashed line also shows alternative settings used in practice (according to the DG settings register provided by NIE Networks). The shaded areas in Figure 18 indicate the conditions which would most likely result in the disconnection of the DG (by UV protection), and thus, compromise the VRT requirement. In order to ensure that the VRT is not compromised an adjustment of the UV protection settings is needed.

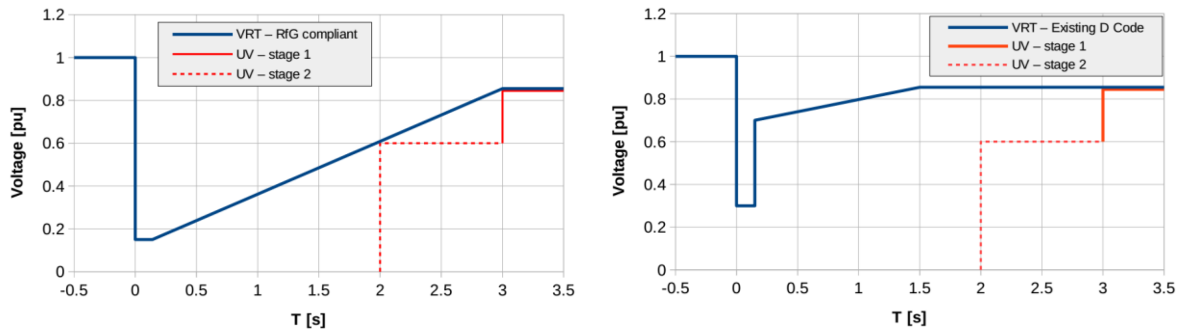
Additionally, in order to conform with the recently-released European requirements for connection of distributed generation (RfG - [5]) the existing VRT characteristic for large scale generation (>5MW) also needs to be revised. The most likely VRT modification agreed in consultation with NIE Networks and SONI is presented in Figure 19a.

Taking into account the anticipated constraints imposed by the VRT requirements in the future, it is recommended to introduce a two-stage UV protection with stage 1 settings at 0.85 pu and 3 s time delay, and stage 2 settings at 0.6 pu and 2 s time delay. As shown in Figure 19 such settings would not compromise any of the VRT characteristics.



a) Large Scale Generation >5MW b) Small Scale Generation <5MW

Figure 18. Existing voltage ride-through requirements and under-voltage settings



a) Large Scale Generation >5MW b) Small Scale Generation <5MW

Figure 19. Anticipated future ride-through requirements and proposed under-voltage settings

4 Summary

4.1 WP1

The detailed analysis of the DG register has been performed using two data sets: (a) existing connected DG only, and (b) existing + contracted generation. This will feed directly into WP3 and WP4 where overall risk assessment figures will be calculated.

4.2 WP2

The stability of ROCOF, VS, OF and UV protection has been investigated which led to the establishment of 8 setting options (outlined in Table 8). These options (or similar alternatives established in discussion with NIE Networks) will be the basis for subsequent comparative risk assessment investigations that will be conducted in WP3 and WP4.

Table 8: Proposed LOM Protection Options

LOM Option	*LOM protection type*	*Settings*
1	ROCOF	0.4 Hz/z (no time delay)
2	ROCOF	2 Hz/s (200ms time delay)
3	ROCOF	1.5 Hz/s (300ms time delay)
4	ROCOF	1.5 Hz/s (500ms time delay)
5	ROCOF	1 Hz/s (800ms time delay)
6	Vector Shift	6°
7	Vector Shift	12°
8	V and f protection only	G59 with the following adjustments: 1. OF at 52 Hz with 1 s delay, 2. Two-stage UV settings stage 1 – 0.85 pu with 3 s time delay stage 2 – 0.6 pu with 2 s time delay

In WP3 and WP4, for each of the proposed options, the non-detection zone (NDZ) will be assessed in terms of minimum real and reactive power difference between the DG output and the “trapped” local load at the time of islanding, and the options that will result in the best performance, in terms of dependable and secure operation of ROCOF (or other G59 protection) will be identified.

5 References

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[3] Bugdal, R., Dysko, A., Burt, G.M., and McDonald, J.R., “Performance analysis of the ROCOF and vector shift methods using a dynamic protection modelling approach,” presented at the 15th International Conference on Power System Protection, Bled, Slovenia, 2006, pp. 139–144.

[4] ‘Distribution Code’. Northern Ireland Electricity Limited, Feb-2015.

[5] Commission Regulation (EU) 2016/631, ‘Establishing a network code on requirements for grid connection of generators’, 14-Apr-2016. [Online]. Available: http://eur-lex.europa.eu/legal-content/EN/TXT/?uri=OJ:JOL_2016_112_R_0001. [Accessed: 04-Jul-2016].