Electricity North West Limited

DETECTION, SUSTAINMENT AND CLOSE-DOWN OF ISLANDS

Final Report

70038087
AUGUST 2018

CONFIDENTIAL

Electricity North **West Limited**

DETECTION, SUSTAINMENT AND CLOSE-DOWN OF ISLANDS

Final Report

TYPE OF DOCUMENT (VERSION) CONFIDENTIAL

PROJECT NO. 70033861
OUR REF. NO. 70038087

DATE: AUGUST 2018

WSP
Amber Court
William Armstrong Drive
Newcastle upon Tyne
NE4 7YQ
Phone: +44 191 226 2000
Fax: +44 191 226 2104
WSP.com

QUALITY CONTROL

Issue/revision	First issue
Remarks	
Date	06/09/2018
Prepared by	L.VEITCH S.OE M. SESHASAYEE
Signature	
Checked by	K.HARMER
Signature	
Authorised by	S.NUTT
Signature	
Project number	70038087
Report number	70038087-**002**
File reference	

CONTENTS

TABLES

FIGURES

APPENDICES

INTRODUCTION

This report constitutes the main deliverable to satisfy the requirements of the Network Innovation Allowance (NIA) Project entitled “Detection and prevention of formation of islands via SCADA”.

The scope of works as required to deliver by WSP is to determine:

- How islands can be detected within the distribution network,
- The requirements for safely closing down an island, and
- The requirements for sustaining an island.

An interim report was published in May 2018; covering the issues involved when operating an island and the methodology for the studies.

Initial results were presented to ENW at a progress meeting in June 2018; which provided an opportunity for ENW to guide WSP and agree the scenarios to be considered in this report.

This report includes results of these studies which consider an island forming at Heysham GSP which highlighted the issues from the interim report. To provide meaningful learning, several initial generation scenarios have been considered upon which parametric studies such as level of demand and large generation intertrip time have been performed.

Based upon these results, WSP has articulated the criteria for sustaining and closing an island when re-establishing connection to the rest of the GB grid which is applicable to an island at any voltage level within the GB network.

1 GENERATOR PROTECTION (G59, G99)

One of the key drivers in using PowerFactory software for the studies was the ability to model and simulate protection relays.

WSP developed a mains protection relay model containing modules for loss of mains and multiple stages of under/over voltage and frequency. The parameters for these models were assigned for each plant from the parameters defined in ER G59/3; which are shown below in Figure 1.

The model developed for this study uses RoCoF as the main loss of mains protection. As it is a derivative quantity it is incredibly sensitive to small changes in numerical state; therefore, a moving average filter was applied to the RoCoF input; which is in line with the way many numerical relays operate.

Voltage Vector Shift protection was not modelled as the use of this has been discouraged as it is more likely to lead spurious tripping [GC0079].

Figure 1 – G59 Generator Protection Settings

	Small Power Station				Medium Power Station	
	LV Protection$		HV Protection$			
Prot Function	Setting	Time	Setting	Time	Setting	Time
U/V st 1	Vφ-n† - 13% = 200.1V	2.5s*	Vφ-φ‡ -13%	2.5s*	Vφ-φ‡- 20%	2.5s*
U/V st 2	Vφ-n† - 20% = 184.0V	0.5s	Vφ-φ‡ - 20%	0.5s		
O/V st 1	Vφ-n† + 14% =262.2V	1.0s	Vφ-φ‡ + 10%	1.0s	Vφ-φ‡ + 10%	1.0s
O/V st 2	Vφ-n†+ 19% = 273.7V	0.5s	Vφ-φ‡ + 13%	0.5s		
U/F st 1	47.5Hz	20s	47.5Hz	20s	47.5Hz	20s
U/F st 2	47Hz	0.5s	47Hz	0.5s	47Hz	0.5s
O/F st 1	51.5Hz	90s	51.5Hz	90s	52Hz	0.5s
O/F st 2	52 Hz	0.5s	52Hz	0.5s		
LoM (Vector Shift)	K1 x 6 degrees		K1 x 6 degrees#		Intertripping expected	
LoM(RoCoF) <5MW§	K2 x 0.125 Hz/s		K2 x 0.125 Hz/s#		-	

RoCoF§ settings for Power Stations ≥5MW				
Date of Commissioning		Small Power Stations		Medium Power Stations
		Asynchronous	Synchronous	
Generating Plant Commissioned before 01/08/14	Settings permitted until 01/08/16	Not to be less than K2 x 0.125 Hz/s# and not to be greater than 1Hz/s¶#, time delay 0.5s	Not to be less than K2 x 0.125 Hz/s# and not to be greater than 0.5Hz/s¶# Ω, time delay 0.5s	Intertripping Expected
	Settings permitted on or after 01/08/16	1Hz/s¶#, time delay 0.5s	0.5Hz/s¶# Ω, time delay 0.5s	Intertripping expected
Generating Plant commissioned between 01/08/14 and 31/07/16 inclusive		1Hz/s¶#, time delay 0.5s	0.5Hz/s¶# Ω, time delay 0.5s	Intertripping expected
Generating Plant commissioned on or after 01/08/16		1Hz/s¶#, time delay 0.5s	1Hz/s¶#, time delay 0.5s	Intertripping expected

During this project, the Energy Networks Association issued Engineering Recommendation G99. This document changes the requirements for distributed generators connecting on or after 17 May 2019. Though it remains to be seen if these settings will be enforced by DNOs to existing plant in the forthcoming months; in the same way as compliance was enforced due to changes in ERG59.

The revised G99 settings are listed below. The changes mainly consist of a rationalising of two stage Under voltage and Over Frequency settings into respective single stage protection functions; and crucially, a standardisation of RoCoF settings to 1Hz/s with a 0.5 second time delay.

The revised settings are shown below in Figure 2.

Figure 2 - G99 Generator Protection Settings

Protection Function	**Type A, Type B and Type C Power Generating Modules**				**Type D Power Generating Modules and Power Generating Facilities with a Registered Capacity > 50 MW**	
	LV Protection(1)		**HV** Protection(1)			
	Trip Setting	Time Delay Setting	Trip Setting	Time Delay Setting	Trip Setting	Time Delay Setting
U/V	$V\varphi\text{-}n^{\dagger}$ -20%	2.5 s*	$V\varphi\text{-}\varphi^{\ddagger}$ -20%	2.5 s*	$V\varphi\text{-}\varphi^{\ddagger}$- 20%	2.5 s*
O/V st 1	$V\varphi\text{-}n^{\dagger}$ + 14%	1.0 s	$V\varphi\text{-}\varphi^{\ddagger}$ + 10%	1.0 s	$V\varphi\text{-}\varphi^{\ddagger}$ + 10%	1.0 s
O/V st 2	$V\varphi\text{-}n^{\dagger}$+ 19%$^{\$}$	0.5 s	$V\varphi\text{-}\varphi^{\ddagger}$ + 13%	0.5 s		
U/F st 1	47.5 Hz	20 s	47.5 Hz	20 s	47.5 Hz	20 s
U/F st 2	47.0 Hz	0.5 s	47.0 Hz	0.5 s	47.0 Hz	0.5 s
O/F	52.0 Hz	0.5 s	52.0 Hz	0.5 s	52.0 Hz	0.5 s
LoM (RoCoF)$^{\#}$	1 Hzs^{-1} time delay 0.5 s		1 Hzs^{-1} time delay 0.5 s		Intertripping expected	
LoM (RoCoF) **Type Tested**$^{\#}$	0.2 Hzs^{-1}		0.2 Hzs^{-1}			

A summary of the classifications of generator size as defined by WSP for the study and interpretations of loss of mains protection settings applied to the network models are shown below in Table 1.

Table 1 - WSP Classification of Generator Sizes and RoCoF Protection Settings

Standard	Size of Generation	WSP Classification of Generator	Synchronous	Asynchronous
G59/3	≥50MW	Large	Intertrip	
	≥5MW, <50MW	Medium	0.5 Hz/s time delay 0.5s	1.0 Hz/s time delay 0.5s
	<5MW	Small	0.125 Hz/s	0.125 Hz/s
G99	≥50MW	Large	Intertrip	
	≥5MW, <50MW	Medium	1 Hz/s time delay 0.5s	
	<5MW	Small		

2 SIMULATION SETUP

NETWORK MODEL

As described in the interim report, the region of ENW's network selected for this study was Heysham GSP, the model for which was extracted from an IPSA file and converted to PowerFactory; to allow for accurate modelling of protection systems, for ease of scenario management and to accelerate studies. The converted model was validated using load flow and short circuit analyses.

Following the conversion, additional modelling of generation and protection was required to allow for dynamic simulation. In all cases listed below, a pragmatic approach was adopted in the decision making. In reality, each machine will have slightly different parameters depending upon construction and may respond differently to a change in frequency or voltage.

It is important to remember that the aim of this study is to produce results which are representative not of Heysham specifically but of the wider GB system; therefore, so long as the parameters and models selected are typical; the results will be valid.

A summary of generation and peak demand as provided by ENW in the IPSA model is shown in Table 2, below and detailed in Appendix A. Most of the plant comprising the 674.4 MW total generation within the Heysham group are individually in excess of 50MW and so subject to inter-trip in the event of loss of mains. The remaining generation is 131.4 MW; which is around 107% of the underlying peak demand plus losses.

Table 2 - Base Case Demand and Generation [MW]

MW	All Plant	Small + Medium (<50MW)
Generation	675.9	131.4
Synchronous	140.4	89.4
Wind	526.0	34.0
PV	9.5	9.5
Demand	111.5	
Losses	11.6	

Note that the losses indicated in the table above are variable losses only in a maximum generation state; furthermore, resistance values for circuits were accepted "as-is"; and are not in any way adjusted for temperature.

SETUP FOR DYNAMIC SIMULATIONS

Synchronous Machine Modelling

Synchronous machines were assigned the GAST governor and IEEET1 exciter dynamic models for frequency and voltage control. Both models were selected for simplicity; and were applied using their default parameters. The default governor model incorporates droop control; there are no isochronous machines.

The inertia constant (H) of each machine was set as 4.0 MWs/MVA which is typical of thermal units.

Wind Turbine Generator Modelling

Templates for wind turbine generators which conform to IEC 61400-27 are available within PowerFactory. These templates which contain all necessary components for modelling a wind turbine in steady state and under transient conditions. They were used to replace the standard induction machine model used in and imported from IPSA. The 2MW type 3A (DFIG) template was used for all plant; after which the number of parallel machines was set to reach the total plant rating.

Generator Protection Relays

Generation protection relays were assigned for each generation plant using the approach and parameters as described in Section 1. Large Machines of 50MW or more were set to inter-trip following the island formation through simulation events. The inter-trip delay time was the subject of a study in its own right; however, the default delay was set at 80ms.

Initial Conditions

Voltage control was enabled on asynchronous machines and Heysham SGT voltage set points were reduced from 1.03 to 1.01 pu to prevent tripping of medium size machines on O/V. This is described in more detail within Section 4.

Under Frequency Load Shedding

UFLS was applied in certain cases; though disabled by default. A custom PowerFactory model was developed to discretely scale all 'lumped' loads at specific frequency levels (based upon local node frequency) though in reality this would likely be achieved by tripping select HV feeders. A moving average filter (i.e. time delay) on the frequency signal (window of 1 second) was introduced to prevent load tripping due to transient frequency dips. The other parameters were set as shown in Table 3 below.

Table 3 – Under-frequency Load Shedding Settings

Stage	Frequency [Hz]	Scale [p.u]
0	>48.8	1.000
1	≤ 48.8	0.950
2	≤48.75	0.900
3	≤48.7	0.800
4	≤48.6	0.725
5	≤48.5	0.650
6	≤48.4	0.575
7	≤48.2	0.500
8	≤48.0	0.450
9	≤47.8	0.400

It should be mentioned that simulated system stability could be affected if there was a reliance upon UFLS and the time delay setting was too long, or if the frequency thresholds and affected demand blocks are 'too close' to one another within the model. In reality, UFLS schemes cannot scale load by any arbitrary percent, they are attached to specific customers (or feeders) which are designated low priority, and the amount of load typically shed would be dependent upon the customer usage patterns and time of day.

3 SCENARIOS

STUDY SCENARIOS

Three generation scenarios were developed to demonstrate the ability to sustain an island; these are described below, with the key figures shown in Table 4:

- High Export – a case which maximises the export at the 400kV transmission system interface by setting all generation to export at rated capacity.
- Low Renewables – a case with low wind and PV.
- Low Import – a case with zero real power import. All large machines (>50MW) are out of service. All wind generation is out of service but all PV was retained.

Table 4 - Study Scenarios

Name	Synchronous Generation	Wind	PV	Total Generation	Initial Net Export at 400kV; with 100% Load From Initial Condition Load Flow
High Export	140 MW (100%) 89.4 MW (excluding large)	526.0 MW / 34.0 MW excluding large	9.5 MW	675.5 MW / 132.5 MW excluding large	552.7 MW, -217.5 MVAr
Low Renewables	140 MW (100%) 89.4 MW (excluding large)	105.2 MW (20%) / 6.8 MW excluding large	4.75 MW (50%)	250 MW / 100.95 MW excluding large	137.6 MW -21.8 MVAr
Low Import	78.6 MW (88% medium + small) (Large Off)	34.0 MW (Large Off)	Zero	112.6 MW	Zero MW, 27.2 MVAr

In all scenarios, the disconnection of the 132kV network from the transmission system is initiated at t=100ms. An inter-trip scheme disconnects all plant of 50 MW or more after 80ms (i.e. t=180ms) by default.

4 BASE CASE STUDY

The base case was intended to be an 'ideal' case designed to demonstrate that an island was feasible within the Heysham 132kV network. The scenario used in this assessment was the High Export case.

One of the immediate issues which arose from initial studies is the restrictiveness of G59/3. The issue is that there is no requirement for a time delay on the loss of mains (RoCoF) setting for small generation (<5 MW). Simulation shows that when the islanding breaker is opened, the initial RoCoF was always greater than the 0.125 Hz/s threshold in every case; which immediately trips the small (<5MW) generators.

The large generation will be set to intertrip, at 80ms delay by default i.e. at t=180ms. At t=180ms, the only generation remaining is the medium sized generation (≥5MW, <50MW), having a total capacity of 104.8 MW – see Table 5. Comparing this with the peak demand of 111.5 MW (Table 2), it is clear that there is insufficient generation following the intertrip; and if remaining synchronous machines are already at maximum power output, frequency will drop leading to collapse of the island.

Table 5 – Generation by Size

Type of Generation	Synchronous	Asynchronous	Total
Large (≥50MW)	51.0	492.0	**543.0**
Medium (≥5MW, <50MW)	80.8	24.0	**104.8**
Small (<5MW)	8.6	19.5	**28.1**
Total	**140.4**	**535.5**	**675.9**

[Blank space intentional]

Scaling the load down to 92% of peak (102.61 MW) results in a power imbalance of just less than 1MW excess generation (adjusting for losses) after the small and large generation is tripped. In this condition an island could form however, the power imbalance prior to inter-tripping the large generation at t=180ms pushes RoCoF beyond G59 thresholds for the medium size machines; also leading to eventual collapse at t=870ms as shown in Figure 3 and Figure 4 below.

Figure 3 – Voltage [p.u] – High Export case with 92% loading

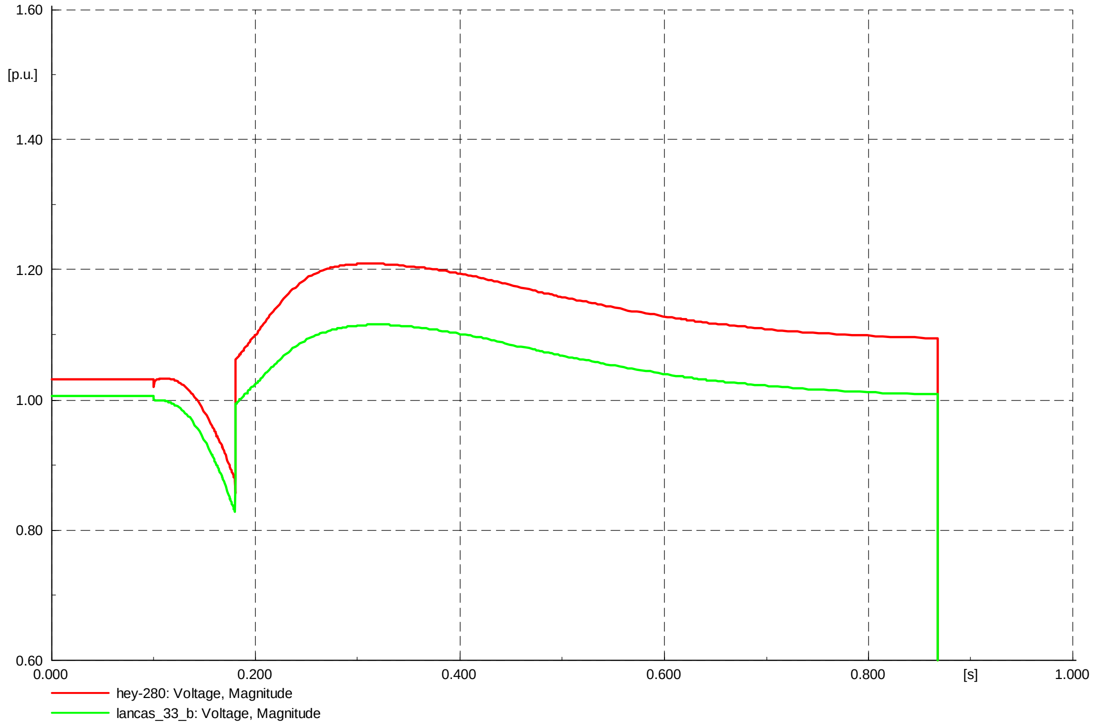
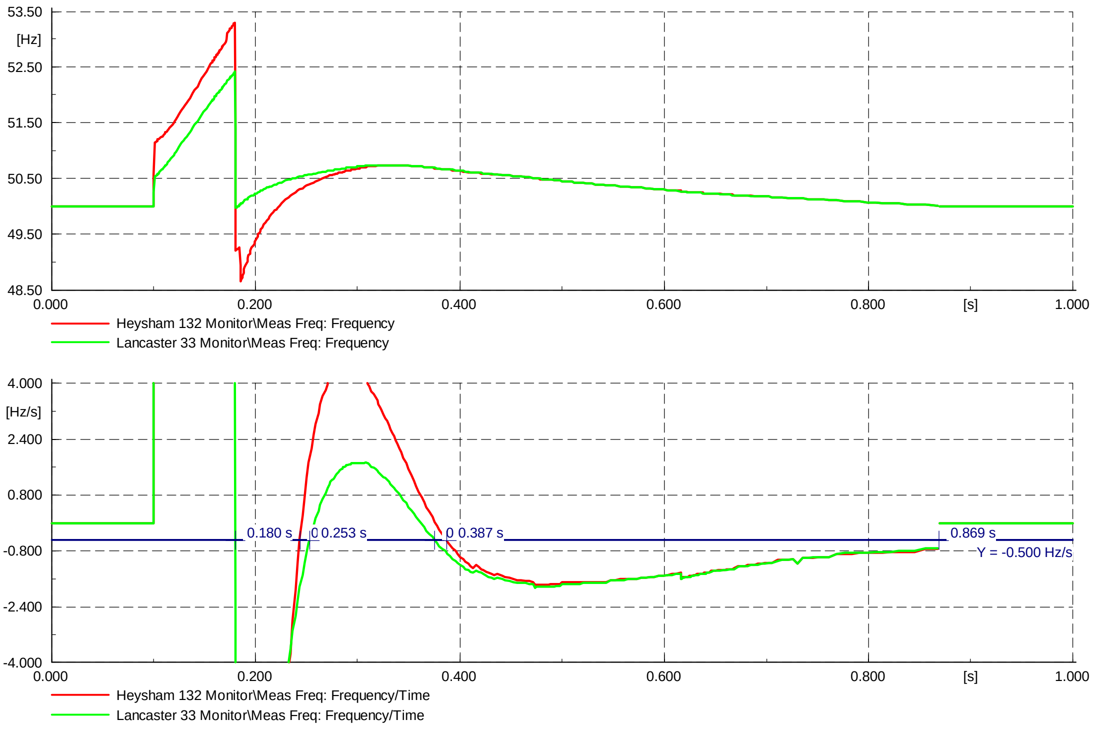
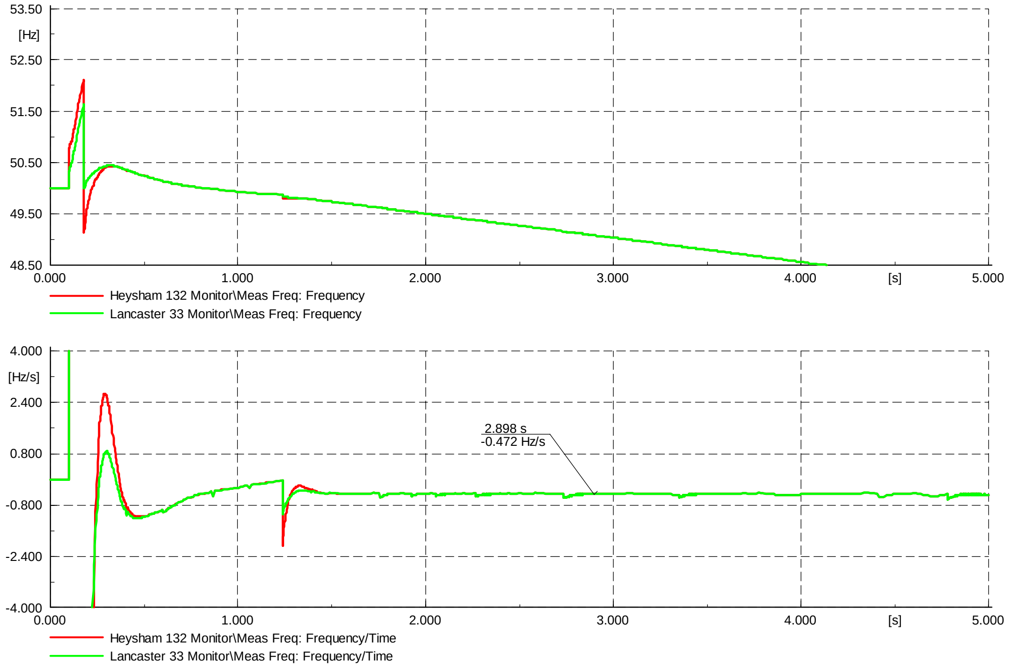


Figure 4 – Frequency [Hz] and RoCoF [Hz/s] – High Export case with 92% loading



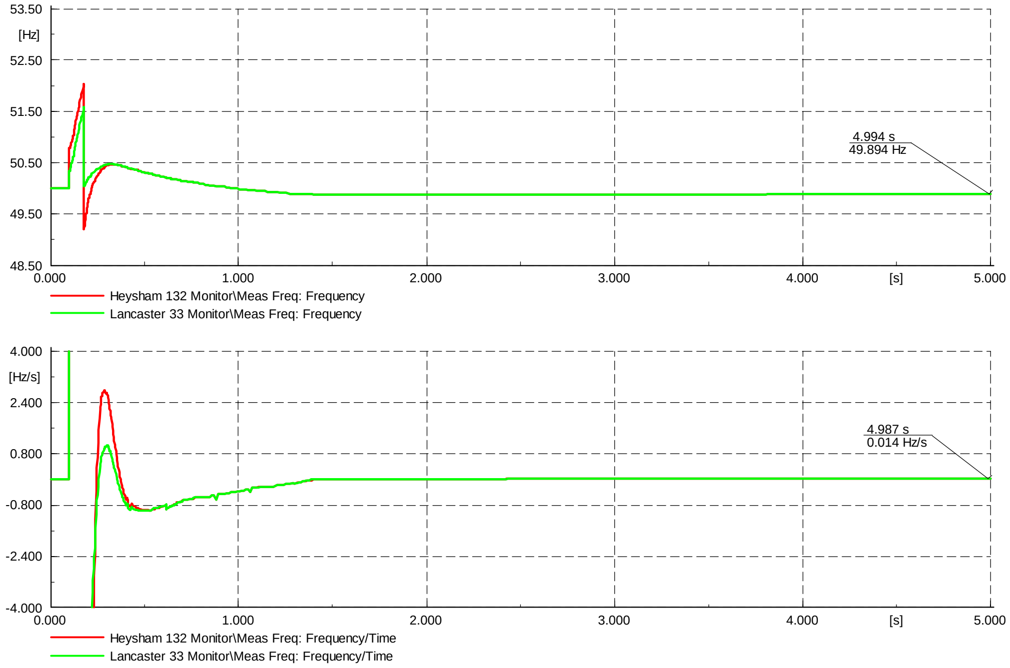
Further reducing demand to 80% or curtailing large wind machines to 60% of their output is sufficient to shorten the duration of frequency decline and prevent the medium machines from tripping on RoCoF within the first second. However, a subsequent transient overvoltage was found to cause one medium sized (8MW) plant to trip at t=1.25s; which leads to frequency decline at around -0.47 Hz/s and tripping of remaining machines on under frequency. This can be seen in Figure 5 below.

Figure 5 - Frequency [Hz] and RoCoF [Hz/s] – High Export case [G59] with 92% loading + curtailed large wind (60%)



To resolve this, the voltage setpoint of the SGTs at Heysham GSP was reduced from 1.03 to 1.01 pu and wind machines set to voltage control mode in the initial condition. In this case the frequency after 5s is 49.89 Hz as shown in Figure 6 .

Figure 6 - Frequency [Hz] and RoCoF [Hz/s] – High Export case [G59] with 92% loading + 60% large wind + voltage control



After applying the homogenous RoCoF settings stated in G99, the small plant (<5MW) will remain connected when the islanding breaker opens; and more medium size synchronous generation will remain connected within the first second. As such, the limitations on load is removed i.e. the network can maintain 100% peak demand, and there is no requirement to curtail any generation. In this case there is a slight steady state over frequency at 50.5 Hz, and 132kV system voltage is less than 1.045 p.u.

Figure 7 - Frequency [Hz] and RoCoF [Hz/s] – High Export case [G99] with 100% loading + 100% large wind + voltage control

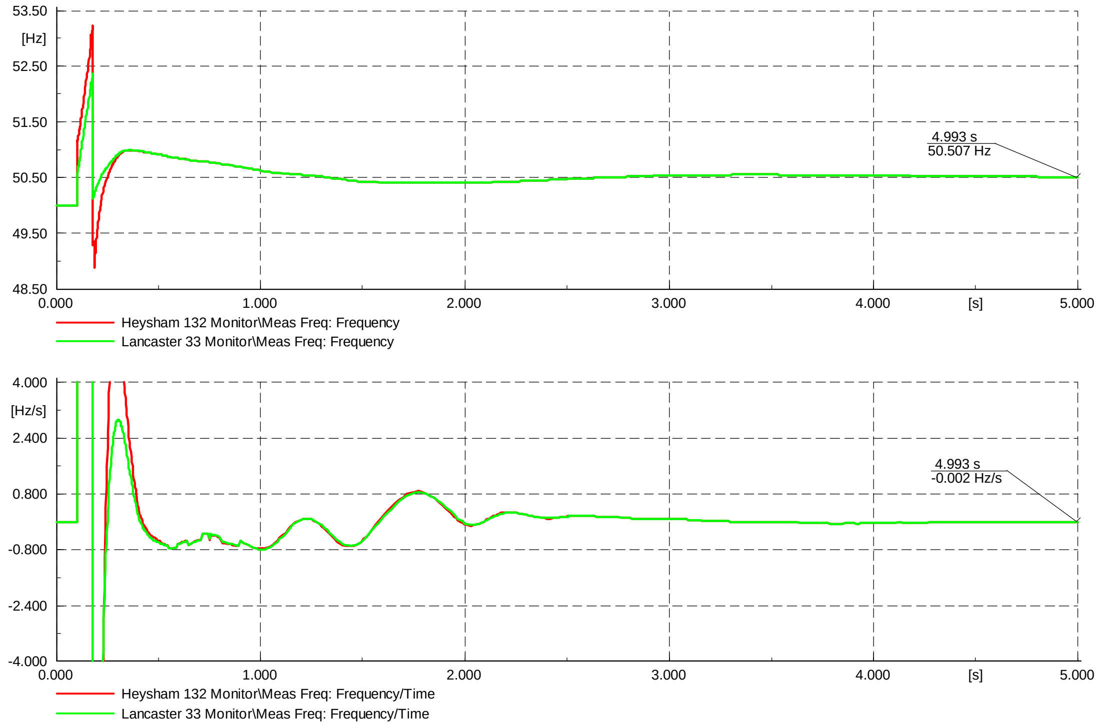
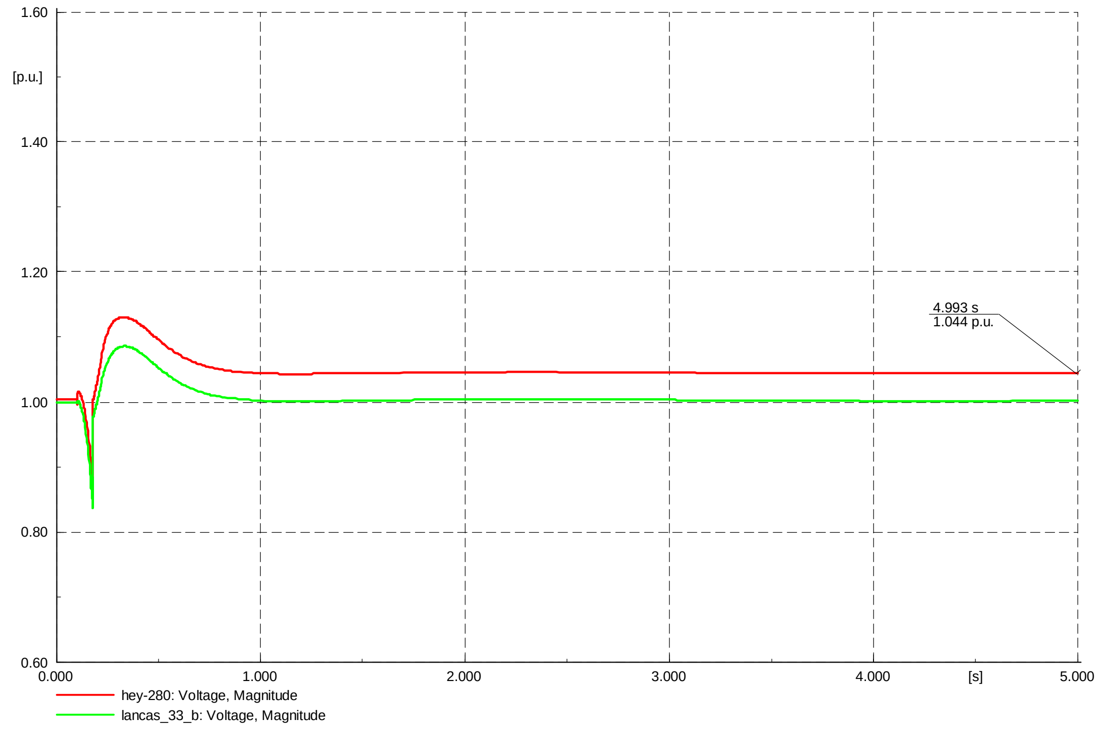


Figure 8 – Voltage [p.u] – High Export case [G99] with 100% loading + 100% large wind + voltage control



CONCLUSIONS OF THE BASE CASE STUDY

- When active power export is high, participation of embedded generation in voltage control is a requirement. All machines initially operate in leading power factor mode.
- Careful selection of transformer voltage set points is influential in maintaining network voltage levels due to lack of reactive power sink when generators trip.
- G59 relay protection settings are restrictive, the 0.125 Hz/s limit for G59 generators (with no specified duration) make them likely to trip at the slightest disturbance.
- G99 settings will allow more generation to be retained due to the increase in RoCoF limit and introduction of a time delay making it possible for an island to be sustained in more load and generation scenarios.

5 LOAD SCALE STUDY

The load scale studies were performed upon variations of the scenarios listed in Section 3. Sensitives included:

- Application of both G59 and G99 relay settings.
- The level of synchronous generation to investigate the effect of reducing system inertia
- Use of under-frequency load shedding (UFLS) schemes.

Throughout this study, the intertrip of generation delay time was fixed at 80ms.

Table 6 – Load Scale Study Cases

Case	Scenario	Protection Standard	Variation
1	High Export	G59	-
2			Without DG189 (21.25MW)
3			Without DG189 (21.25MW) & DG150(21.25MW)
4		G99	-
5			Without DG189 (21.25MW)
6			Without DG189 (21.25MW) & DG150(21.25MW)
7	Low Renewables	G59	-
8		G99	-
9			With UFLS
10	Low Import	G99	-
11			With UFLS

[Blank space intentional]

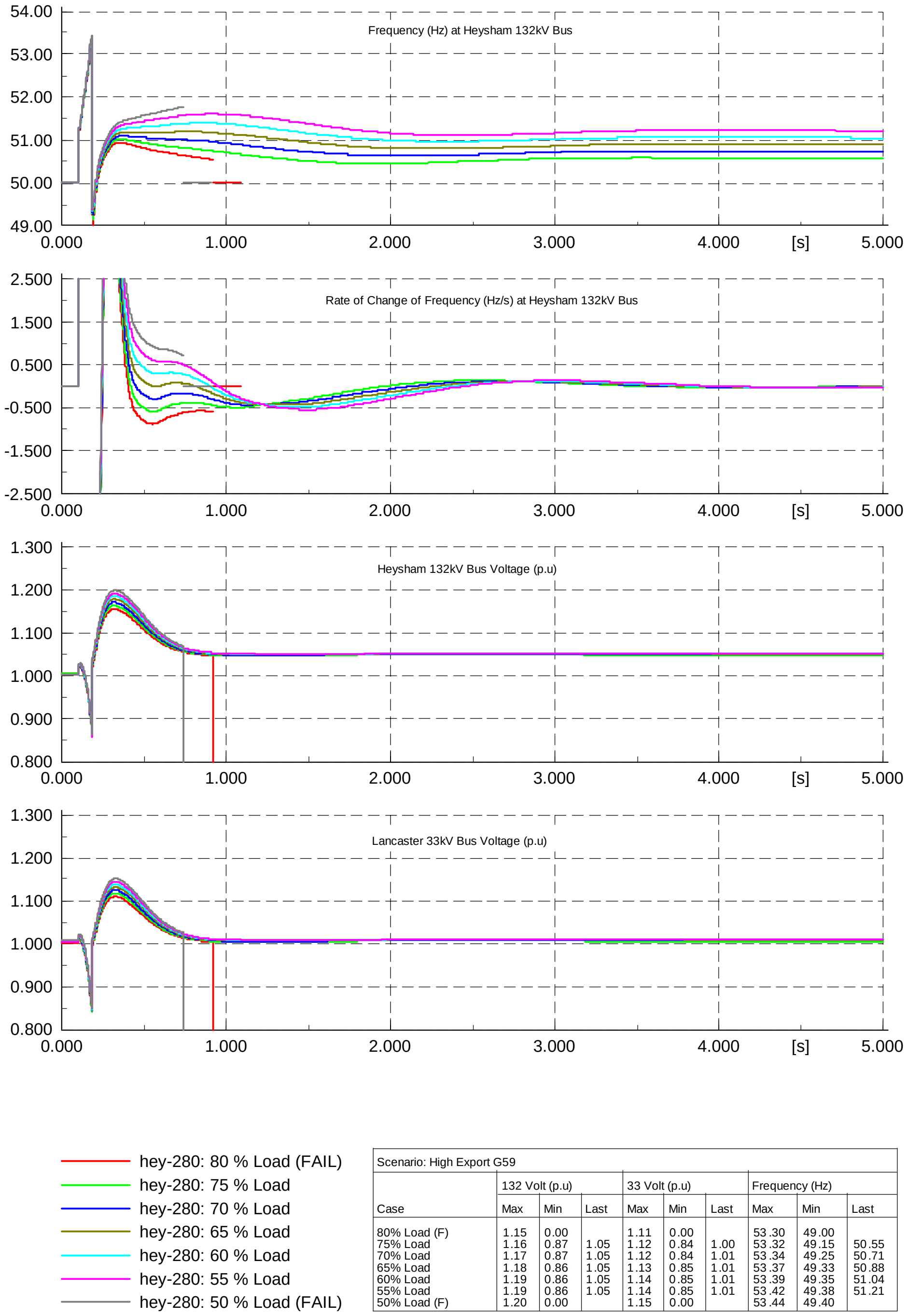
5.1 HIGH EXPORT (G59) CASE

Figure 9 shows that the range of load which can be sustained is 55-75%. In all cases, the small generators trip due to positive RoCoF when the islanding circuit breaker opens. However, when the amount of load is reduced to 50%, the 0.5 Hz/s limit for positive RoCoF is exceeded for over 0.5 seconds for the medium sized synchronous generators. This additional tripping occurs at 740ms and causes the island to become unstable.

When the load is increased to 80%, the medium sized synchronous generators trip because the limits for negative RoCoF are exceeded. Although the RoCoF at 75% load also exceeds this negative limit, the duration of excursion is only 130ms.

As shown in the summary table, in many cases the peak voltages are greater than the G59 O/V stage 2 magnitude limit, but duration is less than 300ms therefore no tripping due to overvoltage is seen.

Figure 9 – High Export (G59) Load Scaling Results



Scenario: High Export G59									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
80% Load (F)	1.15	0.00		1.11	0.00		53 .30	49.00	
75% Load	1.16	0.87	1.05	1.12	0.84	1.00	53 .32	49.15	50.55
70% Load	1.17	0.87	1.05	1.12	0.84	1.01	53.34	49.25	50.71
65% Load	1.18	0.86	1.05	1.13	0.85	1.01	53.37	49.33	50.88
60% Load	1.19	0.86	1.05	1.14	0.85	1.01	53.39	49.35	51.04
55% Load	1.19	0.86	1.05	1.14	0.85	1.01	53.42	49.38	51.21
50% Load (F)	1.20	0.00		1.15	0.00		53 .44	49.40	

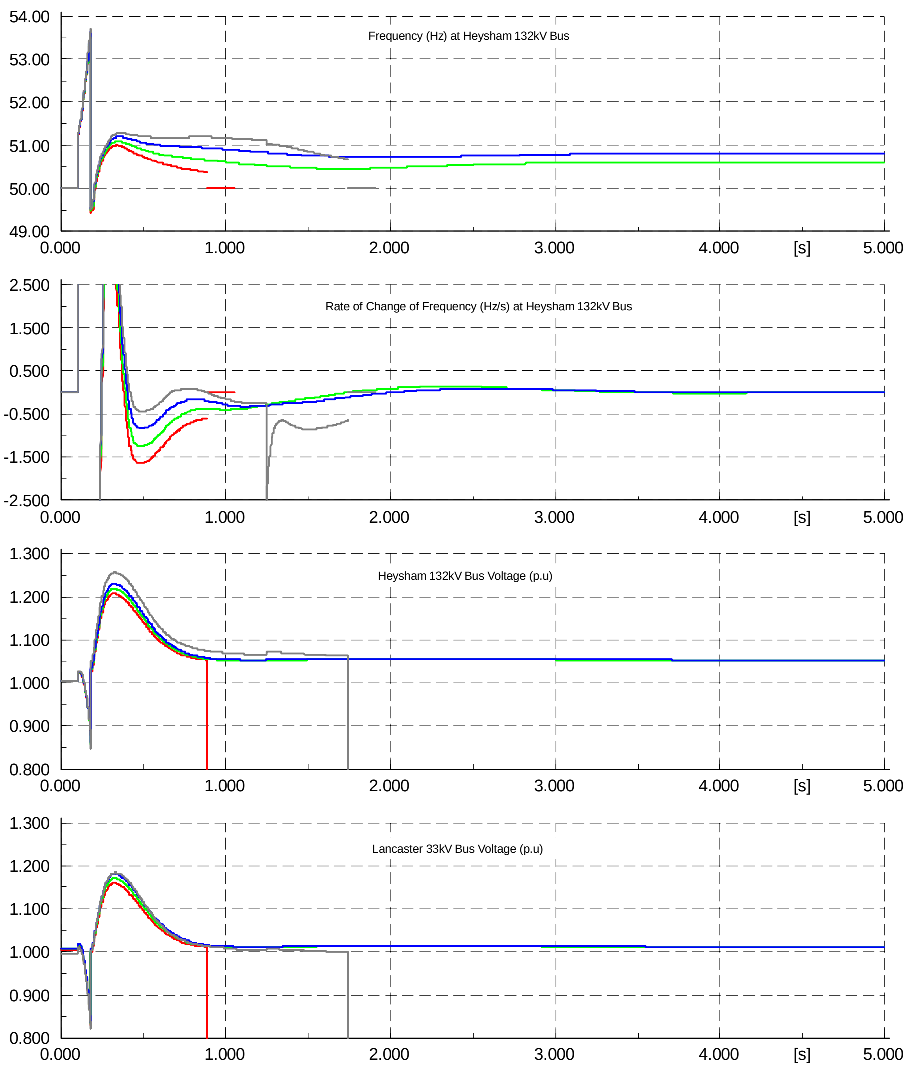
5.2 HIGH EXPORT (G59) WITHOUT DG189 (21.25MW)

When DG189 is taken out of service prior to simulation, the range of load which can be sustained is reduced to 55-60% as shown in Figure 10Table 7. As with the earlier G59 cases, the small generators trip on positive RoCoF when the island forms. When considering a load of 50%, one 8MW wind farm trips at 1.25 seconds on overvoltage. This trip causes the remaining medium sized synchronous generators to trip on negative RoCoF at 1.7 seconds. After this point there is no synchronous generation remaining and the island collapses by 1.8s.

When the amount of load on the system is increased to 65%, the limits for negative RoCoF are exceeded for 0.5 seconds causing the medium sized synchronous generators to trip. This causes the island to collapse at 880ms.

Peak voltage magnitudes are greater than those seen in the previous case but aside the only plant to trip on overvoltage was the 8MW wind farm at 50% load.

Figure 10 - High Export (G59) without DG189 Load Scaling Results



Scenario: High Export G59 NoDG189									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
65% Load (F)	1.21	0.00		1.16	0.00		53.58	49.43	
60% Load	1.22	0.86	1.05	1.17	0.83	1.01	53.61	49.47	50.58
55% Load	1.23	0.86	1.05	1.18	0.83	1.01	53.63	49.50	50.80
50% Load (F)	1.26	0.00		1.18	0.00		53.70	49.50	

5.3 HIGH EXPORT (G59) WITHOUT DG189 (21.25MW) & DG150(21.25MW)

A stable range of load does not exist for this scenario. The island collapses across the full range of load which have been studied.

In all load cases, small generators trip on positive RoCoF when the island forms. Once intertripping occurs only the medium sized generators remain, having total capacity of 62.3MW; therefore, an island would only be possible with a load of 55% or less of the peak demand.

When the load is scaled to 50%, there is an excess of 6.5MW of generation following the loss of the small machines and intertrip of the large machines. However, at 740ms, an 8MW wind farm trips on overvoltage and frequency begins to fall. The RoCoF exceeds the (negative) limit of 0.5Hz/s causing the remaining medium sized synchronous generator to trip and the island to collapse. This is characteristic of lower loading levels.

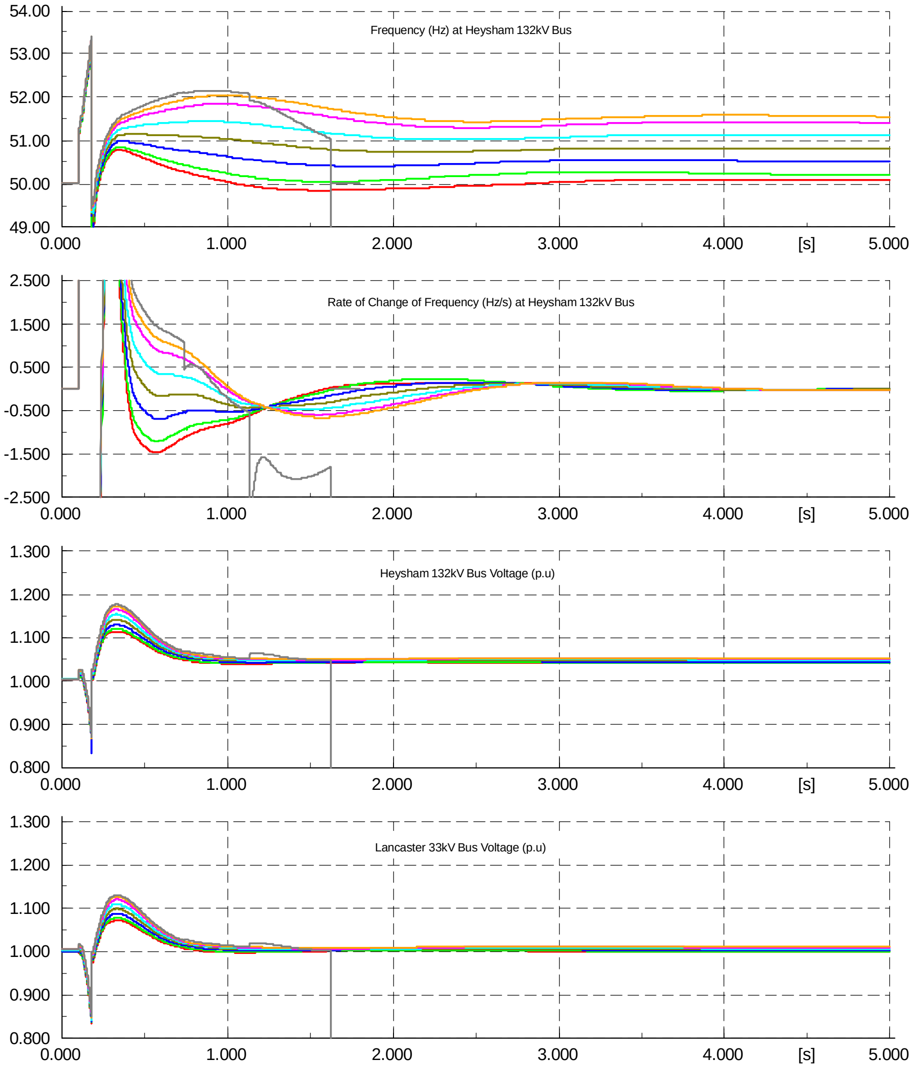
5.4 HIGH EXPORT (G99)

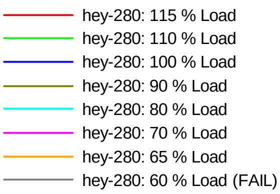
Figure 11 shows that an island can be formed with 65-115% load, when all generation is available and G99 settings are used. The maximum load which the island can theoretically sustain is 117% (when load + losses = total medium + small generation). Scenarios beyond this fail due to generator under-frequency protection.

At 60% load, the limits for positive RoCoF are exceeded for the three small generators connected to Lancaster, tripping at 740ms. At 1.12 seconds, the frequency exceeds the 52Hz limit for over-frequency and the two medium sized wind turbines trip. Following this, the limits for negative RoCoF are exceeded and the remaining small machines and medium sized synchronous machines trip and the island to collapse.

Although the peak voltages exceed the 13% overvoltage limit, no overvoltage tripping is observed.

Figure 11 - High Export (G99) Load Scaling Results





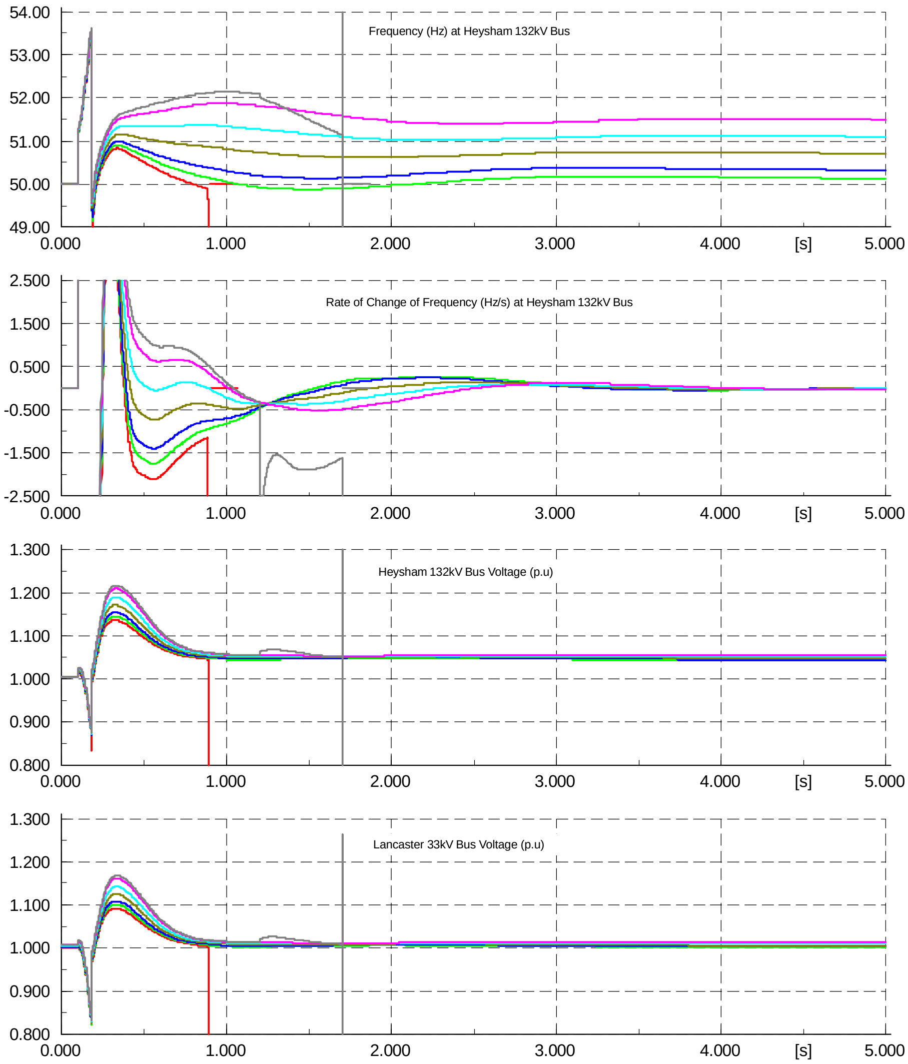
Scenario: High Export G99									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
115% Load	1.11	0.86	1.04	1.07	0.83	1.00	53 .15	48 .62	50 .06
110% Load	1.12	0.86	1.04	1.08	0.83	1.00	53 .17	48 .69	50 .21
105% Load	1.12	0.84	1.04	1.08	0.84	1.00	53 .19	48 .82	50 .36
100% Load	1.13	0.83	1.04	1.09	0.84	1.00	53 .22	48 .88	50 .50
95% Load	1.14	0.84	1.04	1.09	0.84	1.00	53 .24	49 .00	50 .65
90% Load	1.14	0.87	1.05	1.10	0.84	1.00	53 .26	49 .12	50 .80
85% Load	1.15	0.87	1.05	1.10	0.84	1.00	53 .29	49 .17	50 .95
80% Load	1.15	0.87	1.05	1.11	0.84	1.01	53 .31	49 .30	51 .10
75% Load	1.16	0.87	1.05	1.11	0.84	1.01	53 .33	49 .36	51 .24
70% Load	1.17	0.87	1.05	1.12	0.84	1.01	53 .36	49 .38	51 .39
65% Load	1.17	0.87	1.05	1.13	0.85	1.01	53 .38	49 .41	51 .54
60% Load (F)	1.18	0.00		1.13	0.00		53 .40	47 .51	

5.5 HIGH EXPORT (G99) WITHOUT DG189 (21.25MW)

The stable range for this case is 60-115% as shown in Figure 12. As with the previous case, no tripping is observed for cases within the stable range. When the load is scaled to 65%, Caton Moor and a small wind farm trip on over-frequency at 1.2s. At 1.7s the threshold for negative RoCoF is exceeded and all the medium sized synchronous generators trip along with the small machines; collapsing the island. At this point, no synchronous generation remains on the system and the island cannot be sustained.

Again, the peak voltages shown in the summary table exceed the 13% overvoltage magnitude limit but no overvoltage tripping occurs.

Figure 12 - High Export (G99) without DG189 Load Scaling Results



hey-280: 100 % Load (FAIL)
hey-280: 95 % Load
hey-280: 90 % Load
hey-280: 80 % Load
hey-280: 70 % Load
hey-280: 60 % Load
hey-280: 55 % Load (FAIL)

Scenario: High Export G99 NoDG189									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
100% Load (F)	1.14	0.00		1.09	0.00		53.40	49.01	
95% Load	1.14	0.87	1.04	1.10	0.82	1.00	53.42	49.16	50.13
90% Load	1.15	0.87	1.04	1.11	0.82	1.00	53.45	49.22	50.32
85% Load	1.16	0.87	1.05	1.12	0.82	1.00	53.47	49.34	50.51
80% Load	1.17	0.87	1.05	1.12	0.83	1.01	53.50	49.44	50.70
75% Load	1.18	0.87	1.05	1.13	0.83	1.01	53.53	49.48	50.90
70% Load	1.19	0.87	1.05	1.14	0.83	1.01	53.55	49.51	51.09
65% Load	1.20	0.87	1.05	1.15	0.83	1.01	53.58	49.54	51.28
60% Load	1.21	0.87	1.05	1.16	0.83	1.01	53.60	49.57	51.48
55% Load (F)	1.30	0.00		1.26	0.00		53.63	48.08	

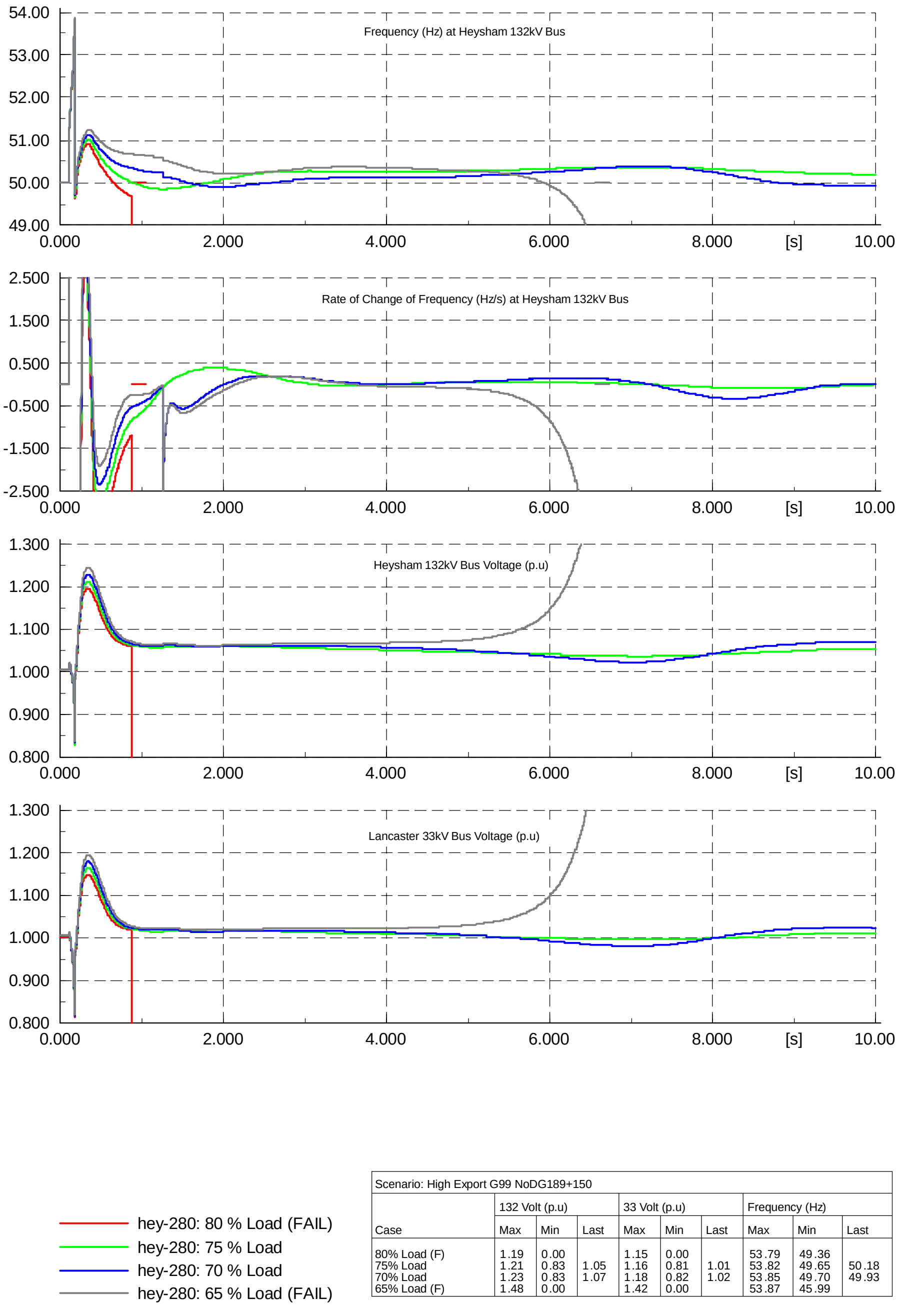
5.6 HIGH EXPORT (G99) WITHOUT DG189 (21.25MW) & DG150(21.25MW)

In contrast to the corresponding case which used G59 settings, an island can be sustained with G99 settings when two of the medium sized synchronous generators are placed out of service however the level of load this is possible for is severely limited, to 70-75% as shown in Figure 13. At 70% an 8MW wind farm trips on overvoltage, however, aside from this no other tripping is observed and the island persists.

When the load is increased to 80%, all small machines and medium sized synchronous generators trip on negative RoCoF at 870ms and the island collapses.

When the load is scaled to 65%, an 8MW wind farm trips on overvoltage at 1.25s. The first machine trip causes frequency to fall, and other plant to trip on (negative) RoCoF. In this case there is insufficient sink for reactive power, causing the voltage to rise as more machines trip. After approximately 6.5 seconds, all remaining small generators and medium sized synchronous generators will disconnect, collapsing the island.

Figure 13 - High Export (G59) without DG189 and DG150 Load Scaling Results



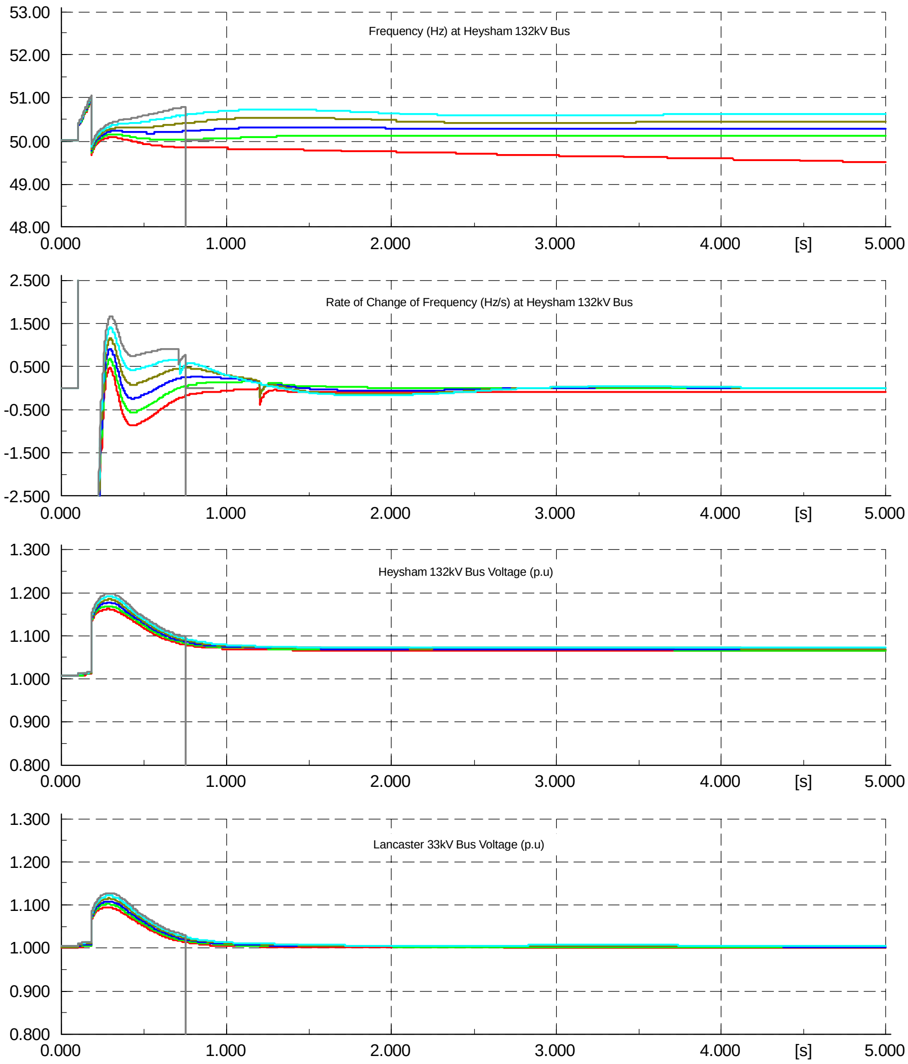
Scenario: High Export G99 NoDG189+150									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
80% Load (F)	1.19	0.00		1.15	0.00		53.79	49.36	
75% Load	1.21	0.83	1.05	1.16	0.81	1.01	53.82	49.65	50.18
70% Load	1.23	0.83	1.07	1.18	0.82	1.02	53.85	49.70	49.93
65% Load (F)	1.48	0.00		1.42	0.00		53.87	45.99	

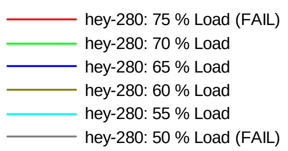
5.7 LOW RENEWABLES (G59)

The stable range for this scenario is between 55-75% as indicated in Figure 14. At 55%, aside from the tripping of the small generators due to positive RoCoF, a medium sized wind farm trips on overvoltage but the system. When the load is decreased to 50%, the same wind farm trips on overvoltage again, however this causes the limits for negative RoCoF to be exceeded. The medium sized synchronous generators trip and the island collapses at 750ms.

At 75% load, the island loses stability due a slow frequency decline of -0.1 Hz/s, eventually tripping on under frequency protection.

Figure 14 - Low Renewables (G59) Load Scaling Results





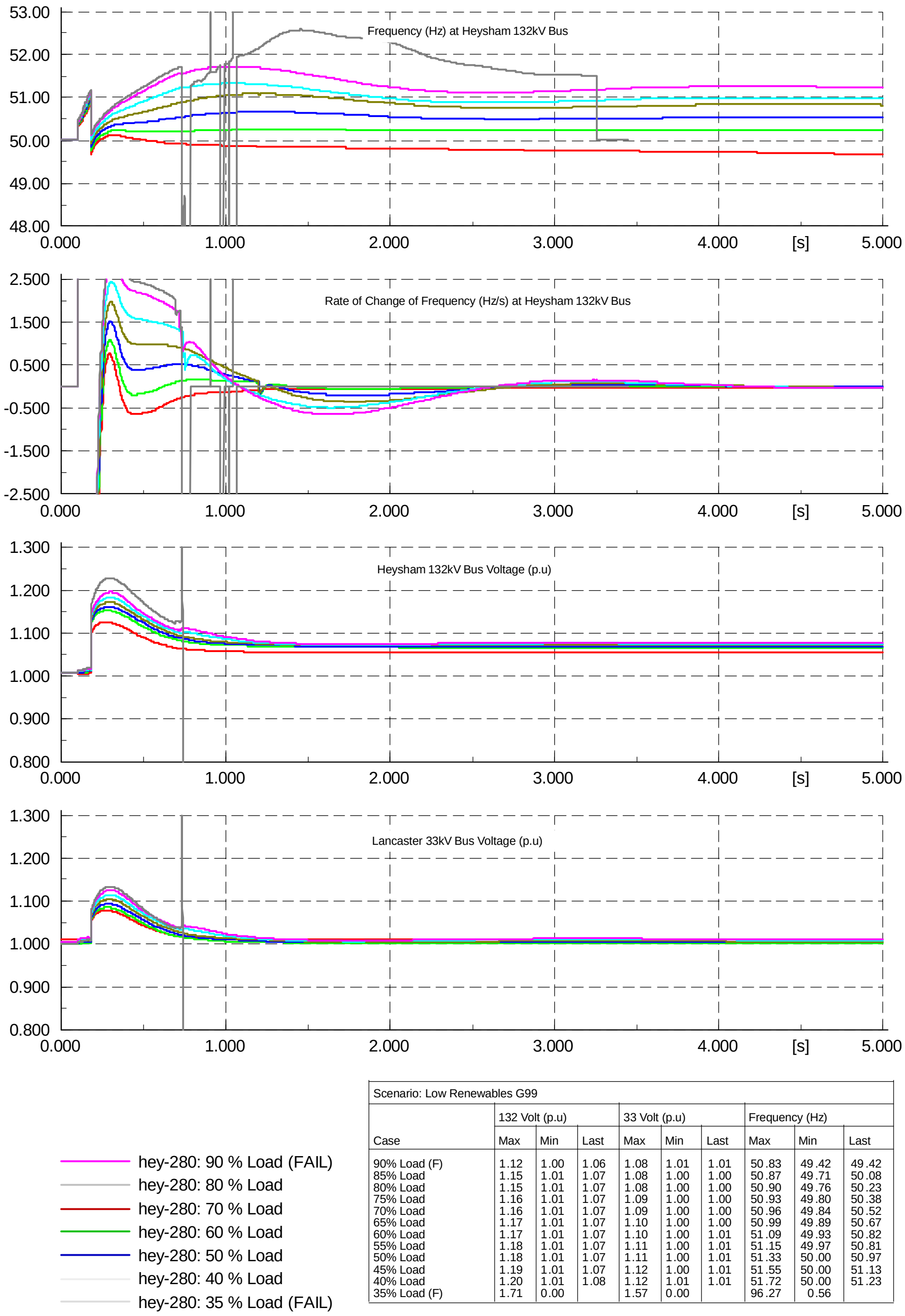
Scenario: Low Renewables G59									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
75% Load (F)	1.16	1.01	1.07	1.09	1.00	1.00	50.89	49.07	49.07
70% Load	1.17	1.01	1.07	1.10	1.00	1.00	50.92	49.73	50.12
65% Load	1.18	1.01	1.07	1.11	1.00	1.00	50.96	49.78	50.29
60% Load	1.18	1.01	1.07	1.11	1.00	1.00	50.99	49.83	50.45
55% Load	1.19	1.01	1.07	1.12	1.00	1.01	51.02	49.87	50.61
50% Load (F)	1.20	0.00		1.13	0.00		51.05	48.93	

5.8 LOW RENEWABLES (G99)

In this scenario, the stable range is 40-85%. As G99 settings are in place, the small generators do not trip initially when the islanding circuit breaker opens at 100ms. At 40% load, the island remains stable although excess generation is tripped on positive RoCoF at around 730ms. When the load is reduced to 35%, an 8MW wind farm trips on overvoltage. At 730ms the small machines and medium sized synchronous generators trip on positive RoCoF causing the system to collapse.

At 75% load, the island loses stability due a slow frequency decline of -0.05 Hz/s, eventually tripping on under frequency protection.

Figure 15 - Low Renewables (G99) Load Scaling Results



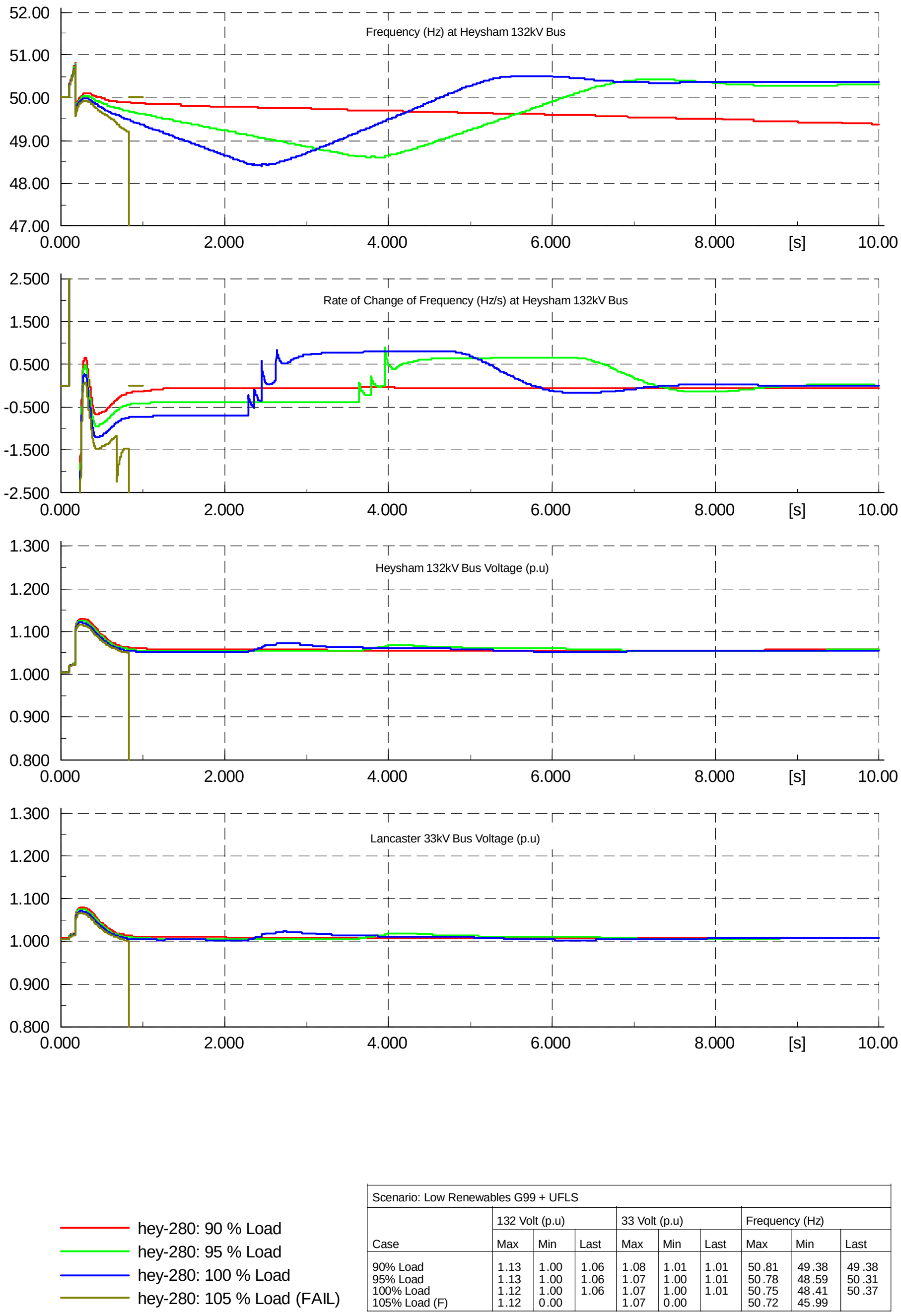
Scenario: Low Renewables G99

	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
90% Load (F)	1.12	1.00	1.06	1.08	1.01	1.01	50.83	49.42	49.42
85% Load	1.15	1.01	1.07	1.08	1.00	1.00	50.87	49.71	50.08
80% Load	1.15	1.01	1.07	1.08	1.00	1.00	50.90	49.76	50.23
75% Load	1.16	1.01	1.07	1.09	1.00	1.00	50.93	49.80	50.38
70% Load	1.16	1.01	1.07	1.09	1.00	1.00	50.96	49.84	50.52
65% Load	1.17	1.01	1.07	1.10	1.00	1.00	50.99	49.89	50.67
60% Load	1.17	1.01	1.07	1.10	1.00	1.01	51.09	49.93	50.82
55% Load	1.18	1.01	1.07	1.11	1.00	1.01	51.15	49.97	50.81
50% Load	1.18	1.01	1.07	1.11	1.00	1.01	51.33	50.00	50.97
45% Load	1.19	1.01	1.07	1.12	1.00	1.01	51.55	50.00	51.13
40% Load	1.20	1.01	1.08	1.12	1.01	1.01	51.72	50.00	51.23
35% Load (F)	1.71	0.00		1.57	0.00		96.27	0.56	

5.9 LOW RENEWABLES (G99) WITH UFLS

When the UFLS scheme modelled, an additional 10% of load can be connected to the system initially i.e. 100% of the peak load. At 90% load, peak load shedding occurs at 19.8s with 16.17MW (5%) of load being disconnected. When the initial load is increased to 95% and 100%, the level of peak load which is shed increases to 26.77MW (20%) at 3.6s and 30.6MW (27.5%) at 2.3s respectively. At 105% the limits of negative RoCoF are exceeded and the island becomes unstable.

Figure 16 - Low Renewables (G99) with UFLS Load Scaling Results

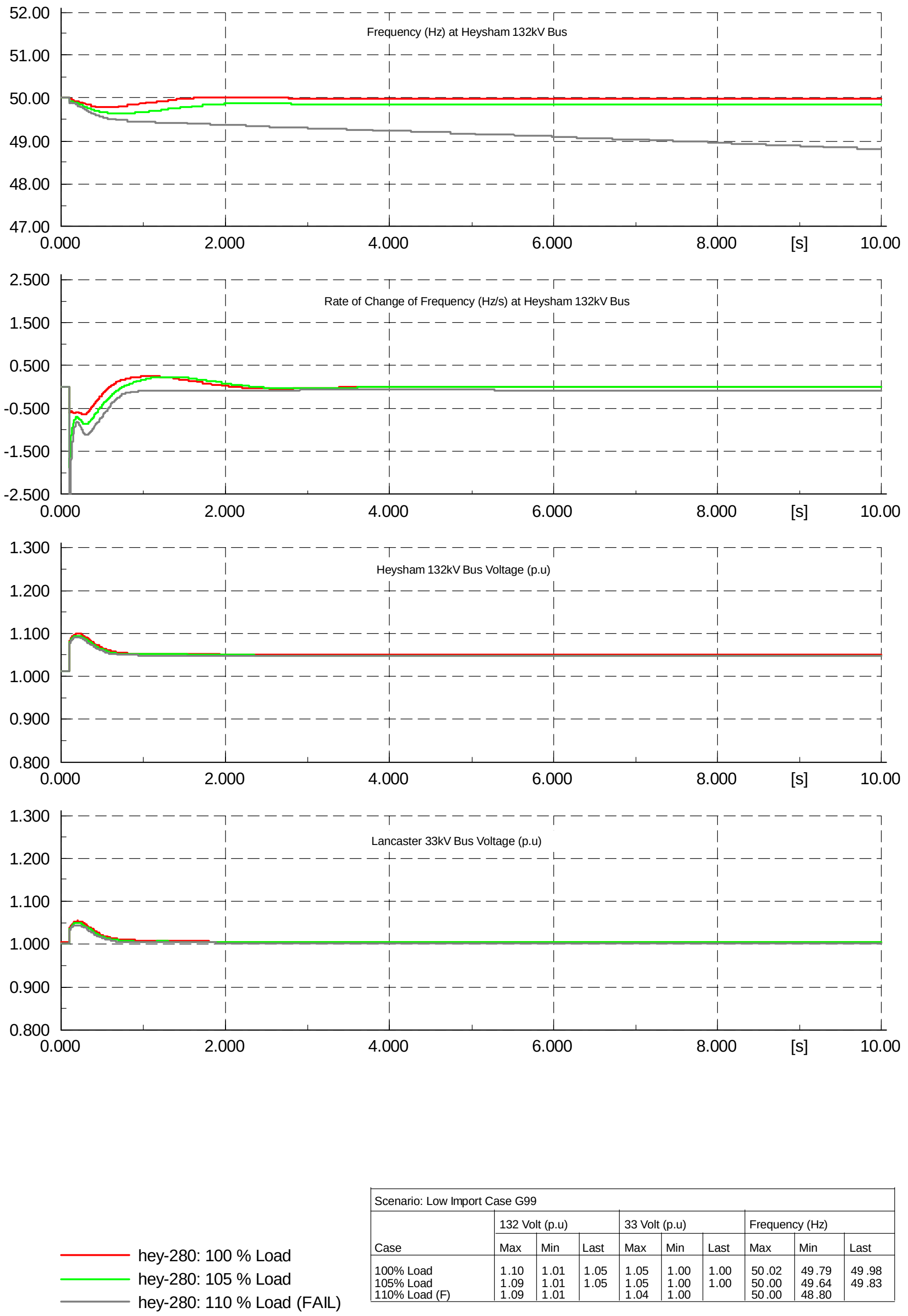


Scenario: Low Renewables G99 + UFLS									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
90% Load	1.13	1.00	1.06	1.08	1.01	1.01	50 .81	49 .38	49 .38
95% Load	1.13	1.00	1.06	1.07	1.00	1.01	50 .78	48 .59	50 .31
100% Load	1.12	1.00	1.06	1.07	1.00	1.01	50 .75	48 .41	50 .37
105% Load (F)	1.12	0.00		1.07	0.00		50 .72	45 .99	

5.10 LOW IMPORT (G99)

This case was investigated with a minimum of 100% load to represent a scenario in which the island would be initially importing power. It can be seen from Figure 17 that up to 105% load can be supported before the island becomes unstable. At 100% and 105%, no generator tripping is observed. When the demand is increased to 110%, frequency begins to fall immediately after intertripping the large machines at a rate of -0.07Hz/s; eventually collapsing after 33 seconds.

Figure 17 – Low Import (G99) Load Scaling Results

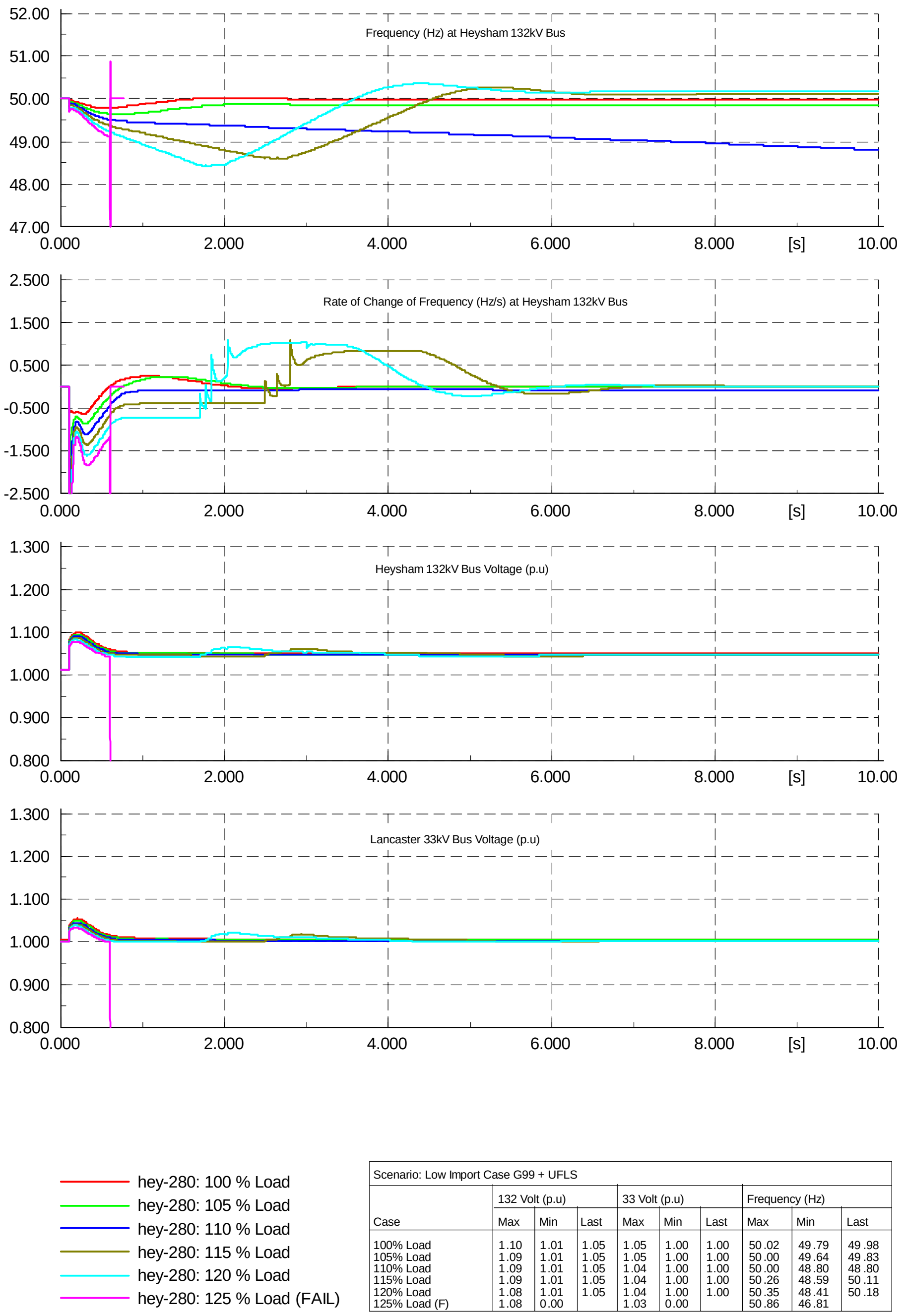


Scenario: Low Import Case G99									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
100% Load	1.10	1.01	1.05	1.05	1.00	1.00	50.02	49.79	49.98
105% Load	1.09	1.01	1.05	1.05	1.00	1.00	50.00	49.64	49.83
110% Load (F)	1.09	1.01		1.04	1.00		50.00	48.80	

5.11 LOW IMPORT (G99) WITH UFLS

When the UFLS is in place for the low import case, an additional 15% i.e. 120% of the peak demand can be initially attached to the Heysham network. At 110% demand, 6.1MW (5%) of load is shed at 10.4s and at 115% demand, 25.65MW (20%) of load is shed at 2.5s. When the load is increased to 120%, 36.8MW (27.5%) is shed at 1.7s. At 125%, the medium sized synchronous generators trip on negative RoCoF at 600ms. Following this, the small machines also trip on negative RoCoF along with Caton Moor wind farm and the island collapses.

Figure 18 – Low Import (G99) with UFLS Load Scaling Results



Scenario: Low Import Case G99 + UFLS									
	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
Case	Max	Min	Last	Max	Min	Last	Max	Min	Last
100% Load	1.10	1.01	1.05	1.05	1.00	1.00	50 .02	49 .79	49 .98
105% Load	1.09	1.01	1.05	1.05	1.00	1.00	50 .00	49 .64	49 .83
110% Load	1.09	1.01	1.05	1.04	1.00	1.00	50 .00	48 .80	48 .80
115% Load	1.09	1.01	1.05	1.04	1.00	1.00	50 .26	48 .59	50 .11
120% Load	1.08	1.01	1.05	1.04	1.00	1.00	50 .35	48 .41	50 .18
125% Load (F)	1.08	0.00		1.03	0.00		50 .86	46 .81	

5.12 SUMMARY

A summary of all results is shown below in Table 7.

The load scaling factors have been transformed into a 'generation margin' above the load,

Table 7 - Load Scaling Study Summary

Case	Protection Standard	Scenario / Case	Theoretical Available Generation after intertrip [MW]	Acceptable Load Scaling Range (%)	Scaled Load Range (MW)	Generation Margin (MW)
1	G59	**High Export**	104.8	75 – 55	83.7 - 61.3	21.1 - 43.4
2	G59	**High Export** Without DG189 (21.25MW)	83.5	60 – 55	66.9 - 61.3	16.6 - 22.2
3	G59	**High Export** Without DG189 (21.25MW) & DG150(21.25MW)	62.3	N/A	N/A	N/A
4	G99	**High Export**	132.9	115 – 65	128.3 - 72.5	4.6 - 60.4
5	G99	**High Export** Without DG189 (21.25MW)	111.6	95 – 60	106.0 - 66.9	5.6 - 44.7
6	G99	**High Export** Without DG189 (21.25MW) & DG150(21.25MW)	90.4	75 - 70	83.7 - 78.1	6.7 - 12.3
7	G59	**Low Renewables**	85.6	70 - 55	78.1 - 61.3	7.5 - 24.2
8	G99	**Low Renewables**	100.9	90 - 45	100.4 - 50.2	0.5 - 50.7
9	G99	**Low Renewables** With UFLS	100.9	100 - 45	111.5 - 50.2	-10.6 - 50.7
10	G99	**Low Import**	112.6	105 - 100**	117.1 - 111.5	-4.5 - 1.1
11	G99	**Low Import** With UFLS	112.6	120 - 100**	133.8 - 111.5	-21.2 - 1.1

** Low Import Case started from 100% demand, at factors less than 100%, case is no longer importing.

5.12.1 CONCLUSIONS OF THE LOAD SCALING STUDY

- To reiterate the conclusions of the base case study, G59 limits the possible number of stable cases due to limitations on RoCoF for very small machines.
- Heavily loaded cases (except high export) typically fail on under frequency. UFLS can be used to extend the range of feasible initial operating states from which an island can be created.
- Simulations show that lightly loaded cases even with G99 settings fail on negative RoCoF. No case studied allows load scaling factor lower than 45%.
- The further reduced the load, the greater the excess generation will be at time of large generator intertrip. Further considerations could be made in the modelling of speed governors; which may provide damping.
- The ratio between the intertripped amount and residual generation is significant. The greater this ratio, the greater rate of change of frequency will be.

6 INTER-TRIP TIME DELAY STUDY

This study is intended to assess the criteria for intertripping time parameters for large generation plant. The methodology was to repeat simulations with intertripping time starting at 40ms and increasing in 10ms increments until an unstable case results. This delay includes all signal propagation, interpretation and contact actuation time between opening of the islanding breaker and remote generator breaker.

6.1.1 ALL GENERATION CASES

The study was initially performed upon the High Export scenario with the maximum demand found in the load variation study. For G59, maximum demand was 75% with G59 settings; for G99, this was 100%. Both conditions result in a predicted excess generation (margin) of approximately 20MW after intertripping large plant as shown below.

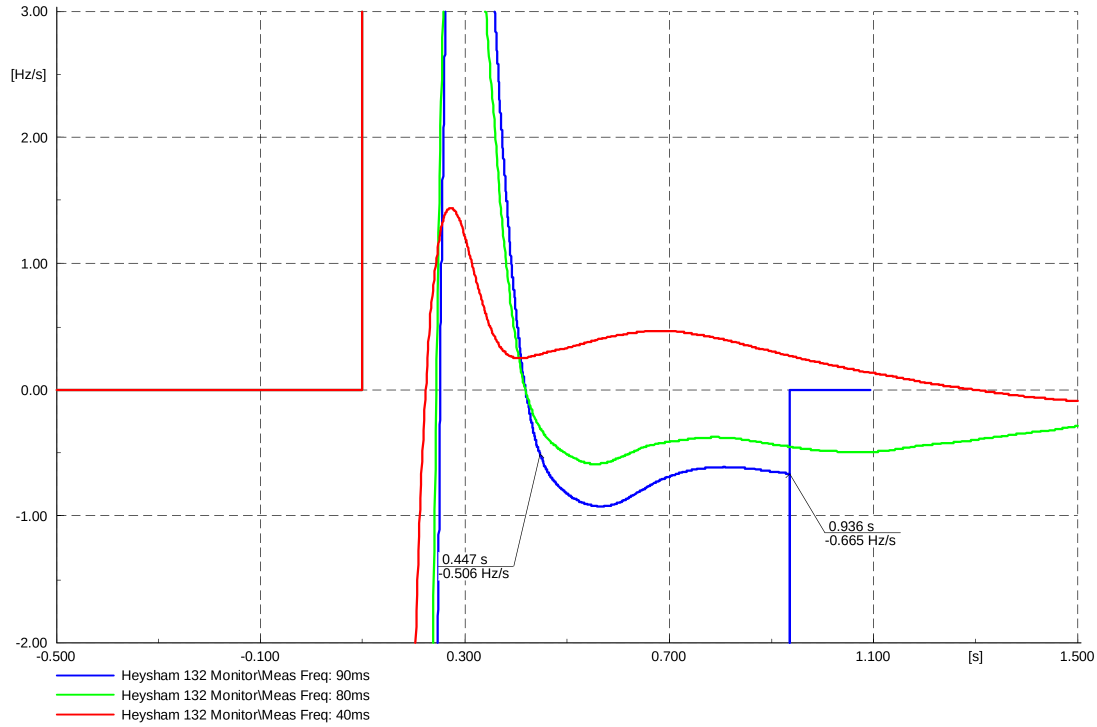
With G59 Settings	With G99 Settings
Medium Generation = 104.8 MW Losses ≈ 1MW Demand @75% = 83.65 MW Power imbalance after intertripping large plant: approximately 20 MW generation margin.	Medium + Small Generation: 104.8+28.1 = 132.9 MW Losses ≈ 1MW Demand @ 100% = 111.54 MW Power imbalance after intertripping large plant: approximately 20 MW generation margin.

6.1.1.1 With G59 settings

With G59 settings, tripping of small generators (<5MW) occurs initially when the islanding circuit breaker opens due to exceedance of the 0.125 Hz/s ROCOF threshold.

It was found that the network remains stable for intertrip times of 40-80ms. When the intertrip time is delayed to 90ms, the ROCOF exceeds (negative) 0.5Hz/s around t=0.44s for over 0.5s as indicated in Figure 19 which causes all remaining synchronous generators to be tripped off. With no synchronous generation, all remaining asynchronous machines will subsequently trip, collapsing the island.

Figure 19 - RoCoF [Hz/s] - High Export Case [G59] with 75% loading, at various intertrip times

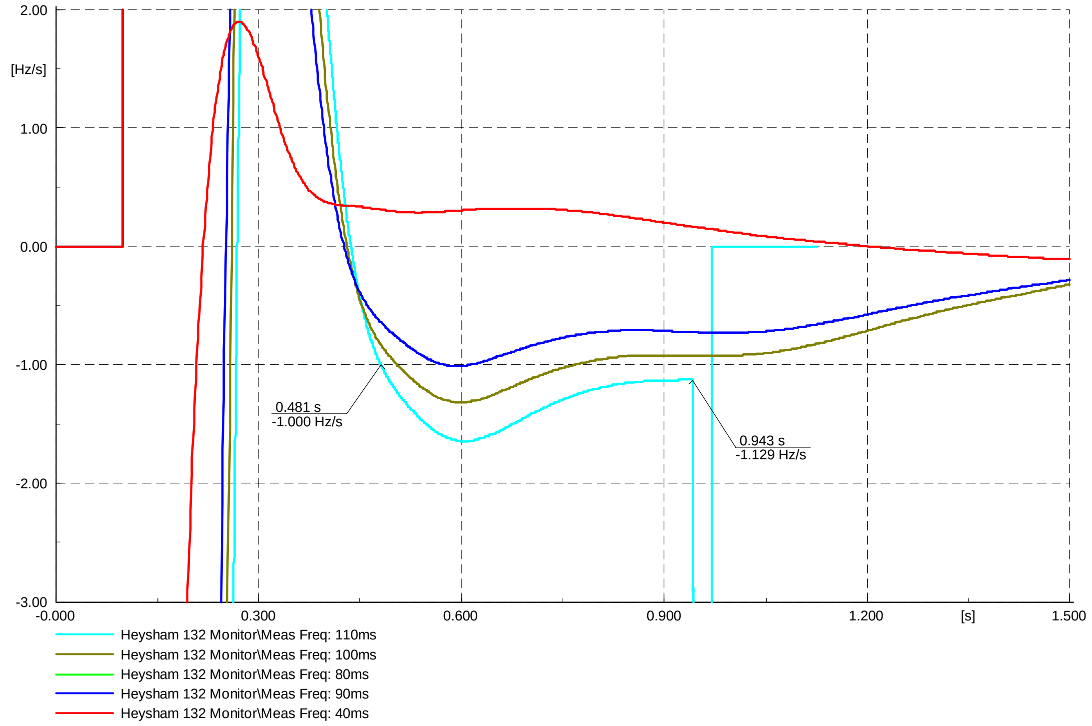


6.1.1.2 With G99 settings

With G99 relay settings, it was found that the island can be sustained for intertrip times up to 100ms as shown in Figure 20.

When intertripping is delayed to 110ms, tripping of all small and medium generation occurs as the ROCOF exceeds negative 1Hz/s for 0.5 seconds. The first (a medium size) generator trips at approximately 940ms, and the remaining generation trips within a further 30ms, causing the island to collapse.

Figure 20 - RoCoF [Hz/s] - High Export Case [G99] with 100% loading, at various intertrip times



[Blank space intentional]

6.1.2 REQUIREMENTS FOR DELAY TRIPPING

Following from the G99 case earlier, to maintain a higher intertrip delay requires the power generation imbalance to increase. To assert this claim, repetitive studies which modify the load scaling factor have been made.

The upper limit of intertrip time with 100% demand was 100ms. 110ms was not achievable with this level demand. The load scaling factor was scaled down in steps of 1% to find the upper and lower limits of load (and excess generation) required to facilitate an intertrip delay of 110ms.

To achieve an intertrip delay of 110ms, it was found that the upper limit of load scaling factor was 95%. Any higher than this will typically cause all generation to trip on RoCoF due to steep frequency decline around t=1s as shown in Figure 22. 95% load scaling corresponds to an absolute load of 106.0 MW; yielding an excess generation of 26.9 MW or around 25% of the scaled demand.

Similarly, the lower limit upon a load scaling factor was 66%. Below this level of load, most generation trips on over frequency protection as shown in Figure 21. 66% load scaling corresponds to an absolute load of 73.6 MW; yielding an excess generation of 59.3 MW or around 81% of the scaled demand.

Figure 21 – Frequency [Hz] at Heysham 132kV bus when facilitating a 110ms intertrip delay time

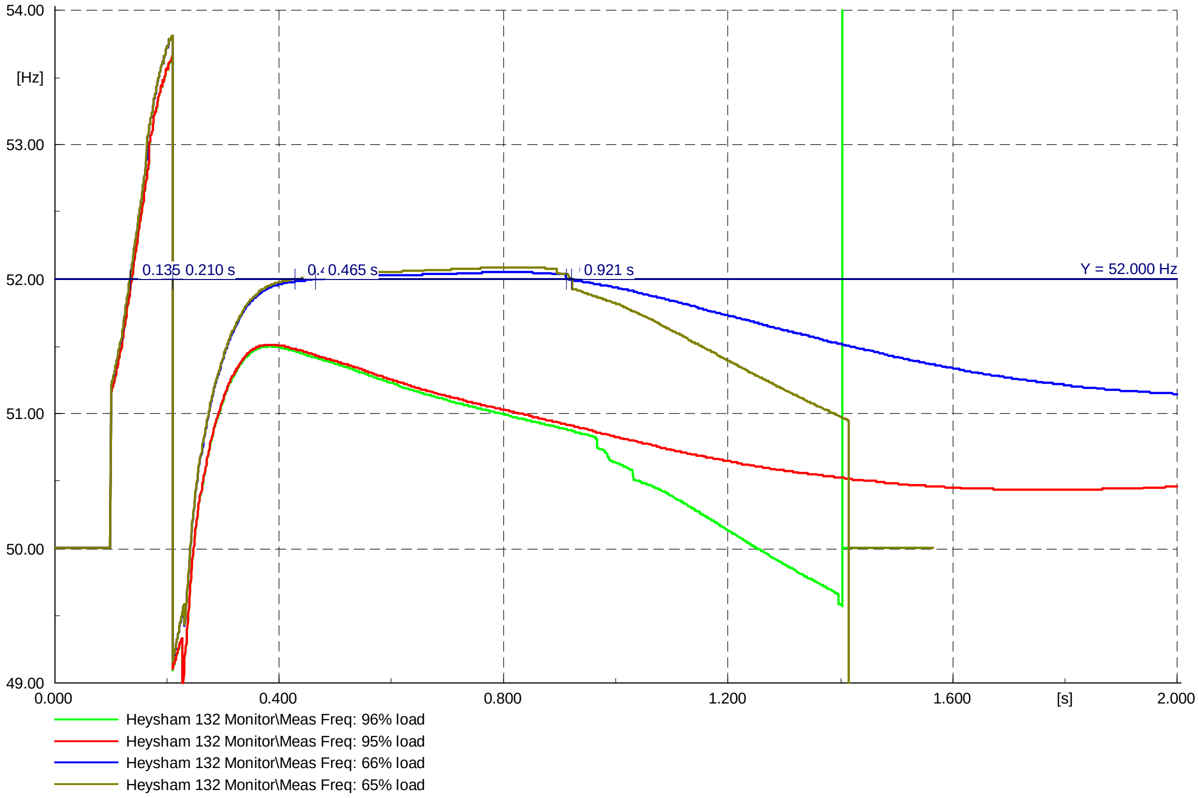
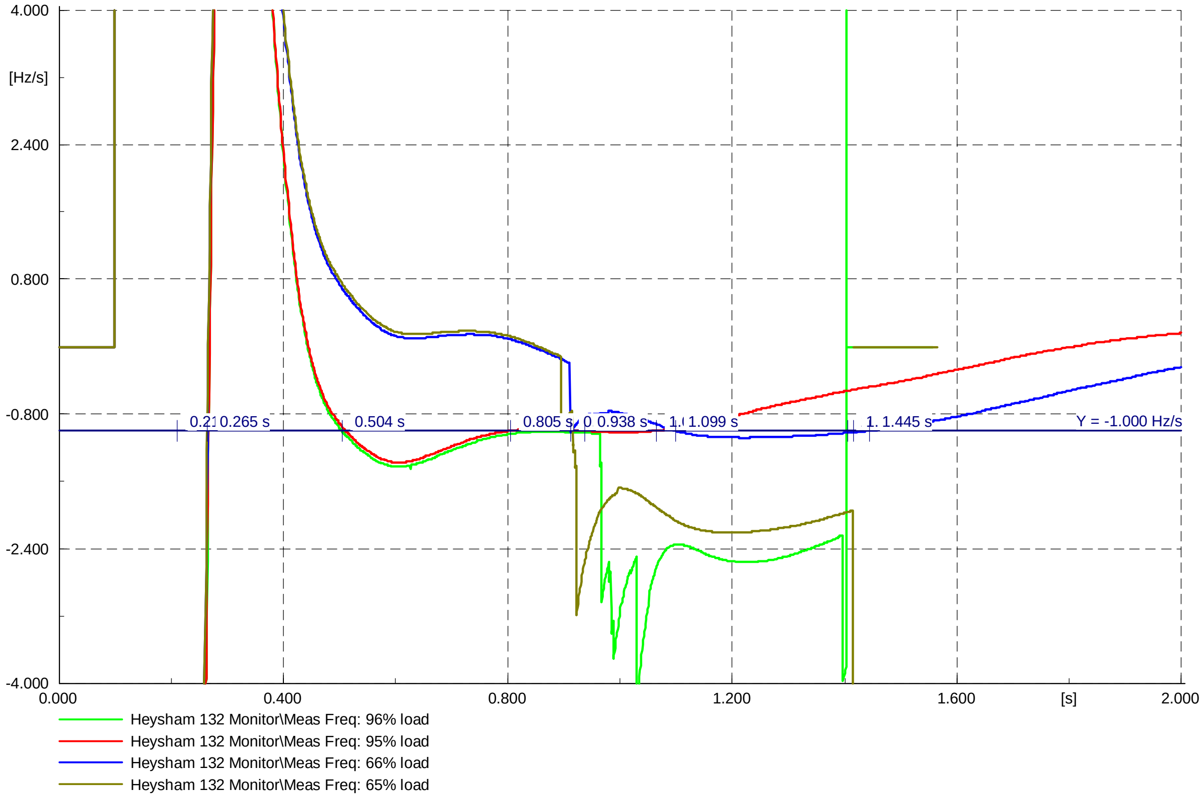


Figure 22 - Rate of Change of Frequency [Hz/s] at Heysham 132kV bus when facilitating a 110ms intertrip delay time



The events described for 110ms are common to all intertrip times tested up to 140ms. It was not possible to facilitate an intertrip delay of 150ms in this scenario.

A summary of results of results is shown in Table 8. This table shows that generally, it is possible to maintain an island for a greater range of generation and load states when a lower intertrip delay time is specified.

Table 8 - Intertrip Results

Intertrip Delay (ms)	Acceptable Load Scaling Range (%)	Scaled Load Range (MW)	Estimated Generation Margin (MW)	Estimated Generation Margin (% of total generation)
20	117 - 46	130.5 – 51.3	2.4 – 81.6	2 – 61 %
40	117 - 65	130.5 – 72.5	2.4 – 60.4	2 – 45 %
60	117 - 61	130.5 – 68.0	2.4 – 64.9	2 – 49 %
80	117 - 62	130.5 – 69.2	2.4 – 63.7	2 – 48 %
100	101 - 65	112.7 – 72.5	20.2 – 60.4	15 – 45 %
110	95 – 66	106.0 - 73.6	26.9 - 59.3	20 – 45 %
120	88 - 68	98.2 – 75.8	34.7 – 57.1	26 – 43 %
130	82 - 69	91.5 – 77.0	41.4 – 55.9	31 – 42 %
140	76 - 71	84.8 – 79.2	48.1 – 53.7	36 – 40 %

6.1.3 CONCLUSION OF THE INTERTRIPPING STUDY

- It is possible to maintain an island for a greater range of generation and load states when a lower intertrip delay time is specified
- As G99 settings allows more small generation to be retained, the intertrip time could also be increased.

7 POWER FACTOR STUDY

In this study, the impact of varying the power factor on system stability was investigated.

Inductive loads with power factors down to 0.8 can be found in networks today. Capacitive loads are not commonly seen, however medium voltage systems could draw real power and feasibly export reactive power to (sub)transmission networks which would be seen as a net capacitive load; though the expectation is that would likely be in an automatic response through some form of voltage regulation rather than as a normal operating condition.

The methodology to investigate the impact of power factor was to scale reactive power whilst maintaining a fixed real power load using the High Export scenario with G99 relay settings only. The calculated scaling factors for a range of power factors on the initial total gross demand in the system model (111.54 MW; 13.40 MVAr) are shown in Table 9 below.

Table 9 - Power Factor Study Cases

Load Real Power Scaling	Load Type	PF	Load Reactive Power Scaling (%)	Resulting Total MVAr Load
100.0% (111.54 MW)	Inductive	0.80	624.20	83.65
		0.85	515.80	69.12
		0.90	403.09	54.02
		0.95	273.55	36.66
		Unity	0.00	0.00
	Capacitive	-0.95	-273.55	-36.66
		-0.90	-403.09	-54.02

As shown in Figure 23, the island can be sustained for inductive load power factors from unity to 0.8. At unity, an 8MW wind farm trips on over-voltage around t=1.25s after which the system voltages return within the thresholds – this issue was previously documented in the base case results (Section 4). Aside from this, no other tripping is observed for unity or any of the other leading power factors. It can also be seen that as the power factor increases, the value at which the voltage reaches a steady state reduces.

Figure 23 – 132kV bus voltage [p.u] for inductive load power factors at 100% Real power Demand

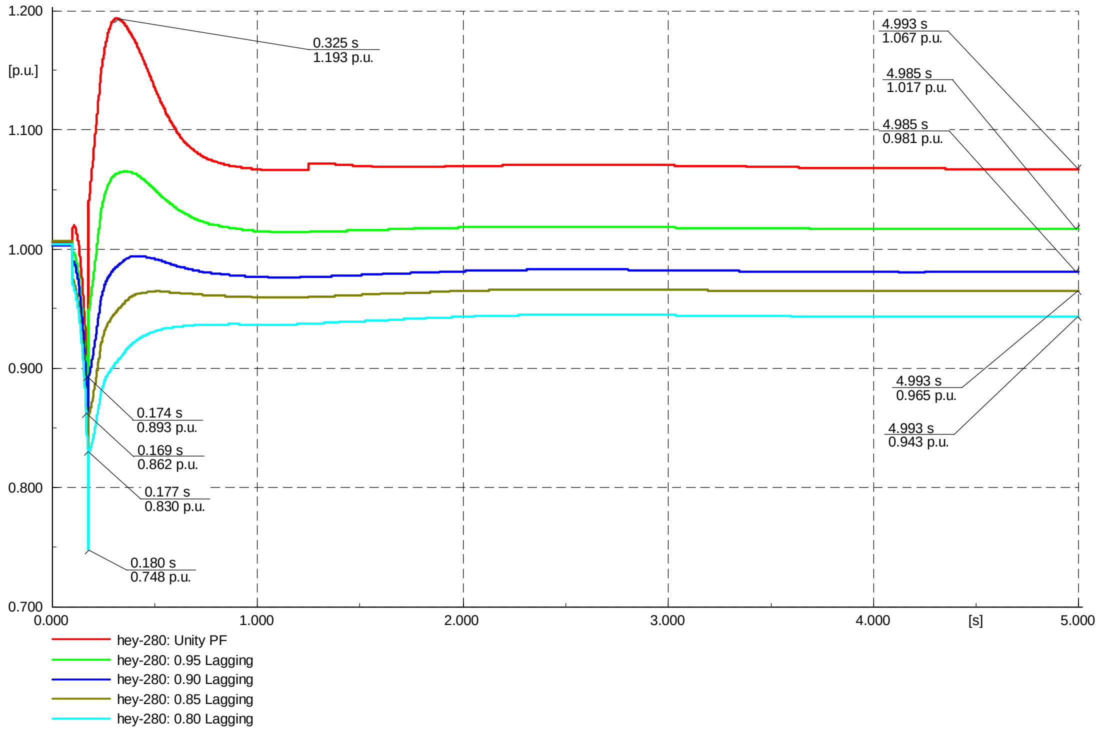
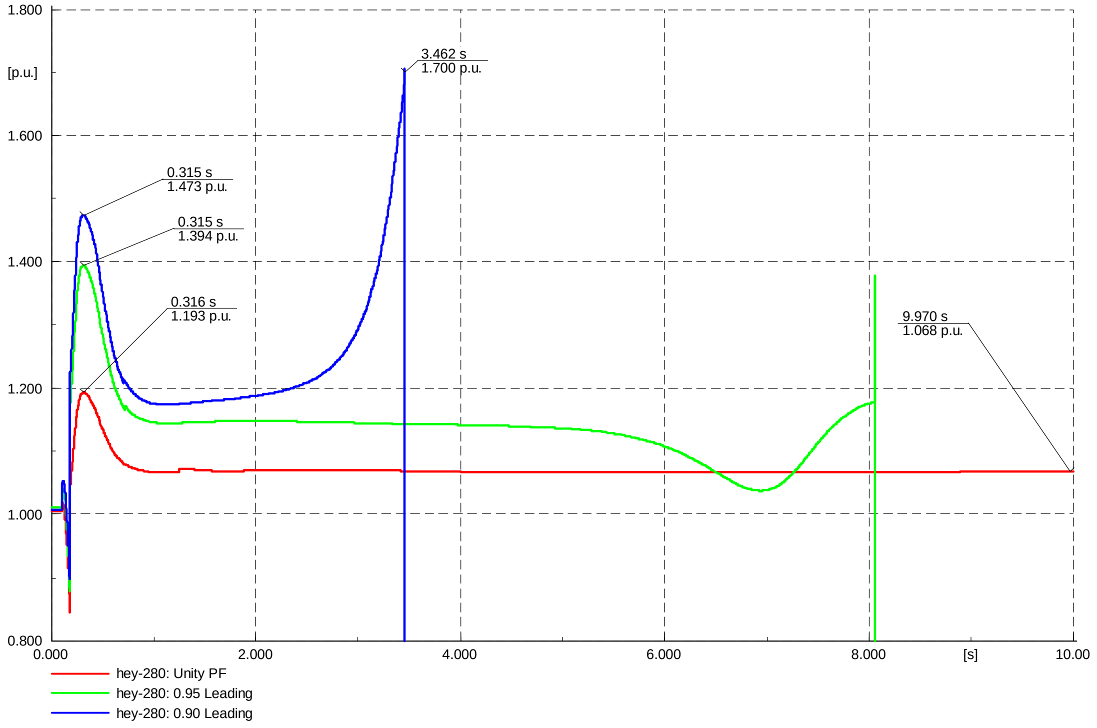


Figure 24 shows that it is not possible to sustain an island for the leading power factors considered. At 0.95 leading power factor, the same 8MW wind farm trips on O/V stage 2 at t=725ms. The loss of this generator (operating in leading power factor mode) compounds the lack of reactive power sink and voltage continues to rise. System collapse can be seen at around t=8 seconds; during a slow oscillation causing remining generation to trip on RoCoF. At 0.90 leading power factor the collapse can be seen sooner, at around t=3.5 seconds.

Figure 24 - 132kV bus voltage [p.u] for capacitive load power factors at 100% Real power Demand



Conclusions of the Power Factor Study

- Networks with higher lagging (and tending toward leading) load power factors, are more likely to encounter tripping on overvoltage.
- Capacitive loads reduce the possibility of operating an island due to limited dedicated reactive power sink, compounded when the first generator trips considering most operate initially with a leading power factor.

8 CRITERIA FOR SUSTAINING AN ISLAND

The common themes from the individual studies and criteria for sustaining an island are presented below, with some recommendations following.

G59 and G99

G59/3 restricts the ability for a network to form an island. As seen in the studies, the main issue is the lack of a defined time delay for Rate of Change of Frequency loss of mains protection. In all studies with G59 settings, small (<5MW) generation trip as soon as the islanding breaker opens. As a loss of mains protection, these settings do function as expected, however small machines with G59 protection relays may be susceptible to nuisance tripping due to other disturbances. If the network operator intends to operate a network with a high penetration of small generators as an island, a move to G99 relay settings is undoubtedly required.

G99 settings allow more generation to be retained and operate as an island; and allow for greater durations of intertripping time as a result which may be advantageous if signal propagation and hardware limitations exist, though it is recommended to minimise intertrip time where possible.

Network Load, Initial Conditions and Voltage Control

It has been observed that networks with higher lagging (and tending toward leading) load power factors, are more likely to encounter generation tripping on overvoltage. It is no surprise, as the network as studied has limited reactive power sink modelled; and in high export cases, embedded generators are required to operate with leading power factors.

Though power factor correction capacitors may be used at lower (medium) voltage levels to reduce losses, this has a tangible consequence of reducing the possible initial conditions from which an island can be formed; with studies showing that an island could not be sustained with capacitive loads.

Initial operating state can also impact the potential stability of a future islanded state; particularly when considering voltage control set points and mechanisms. All simulations performed start with a *reasonable* voltage profile; achieved through a combination of transformer tap settings and generator overexcitation. If that capability is provided by the machines directly (such as synchronous machines), the ability to supress the network voltages will diminish as machines trip off.

Careful selection of set points which could be load and generation (or margin) dependent will extend the ability for an island to form. Embedded generators with separate dispatchable static Var systems would assist in this regard.

Network Load

Load shedding schemes can be used to extend the possible number of initial conditions from which an island can form; which particularly benefits heavily loaded cases which would otherwise fail due to generator tripping on under frequency protection. UFLS has only limited usefulness, as if the load is too far in excess of generation, it is likely that plant will trip on Rate of Change of Frequency first.

Future Connections

The current requirement is to intertrip large (>= 50 MW) machines. Simulations have shown that this act of intertripping can cause other smaller machines to follow. The operator may consider limiting the number and size of future generation connections to 132kV voltage to less than the threshold for large machines (50MW) as they require intertrip.

Furthermore, the requirement to intertrip should be challenged. With the correct grid energy storage or load bank equipment, machines could be gradually ramped down instead; which could be an economic alternative to potentially disconnecting customers if a balance between load and generation cannot be achieved.

9 CLOSING DOWN AN ISLAND

When attempting to connect two systems it is crucial to match voltage magnitude and angle; and frequency on both sides of the open circuit breaker(s) before closing. Poor synchronizing can damage generators and prime movers due to mechanical stress caused by rapid acceleration or deceleration and can cause frequency and/or power oscillations leading to instability or which could damage other equipment. These disturbances may also cause protective equipment to operate.

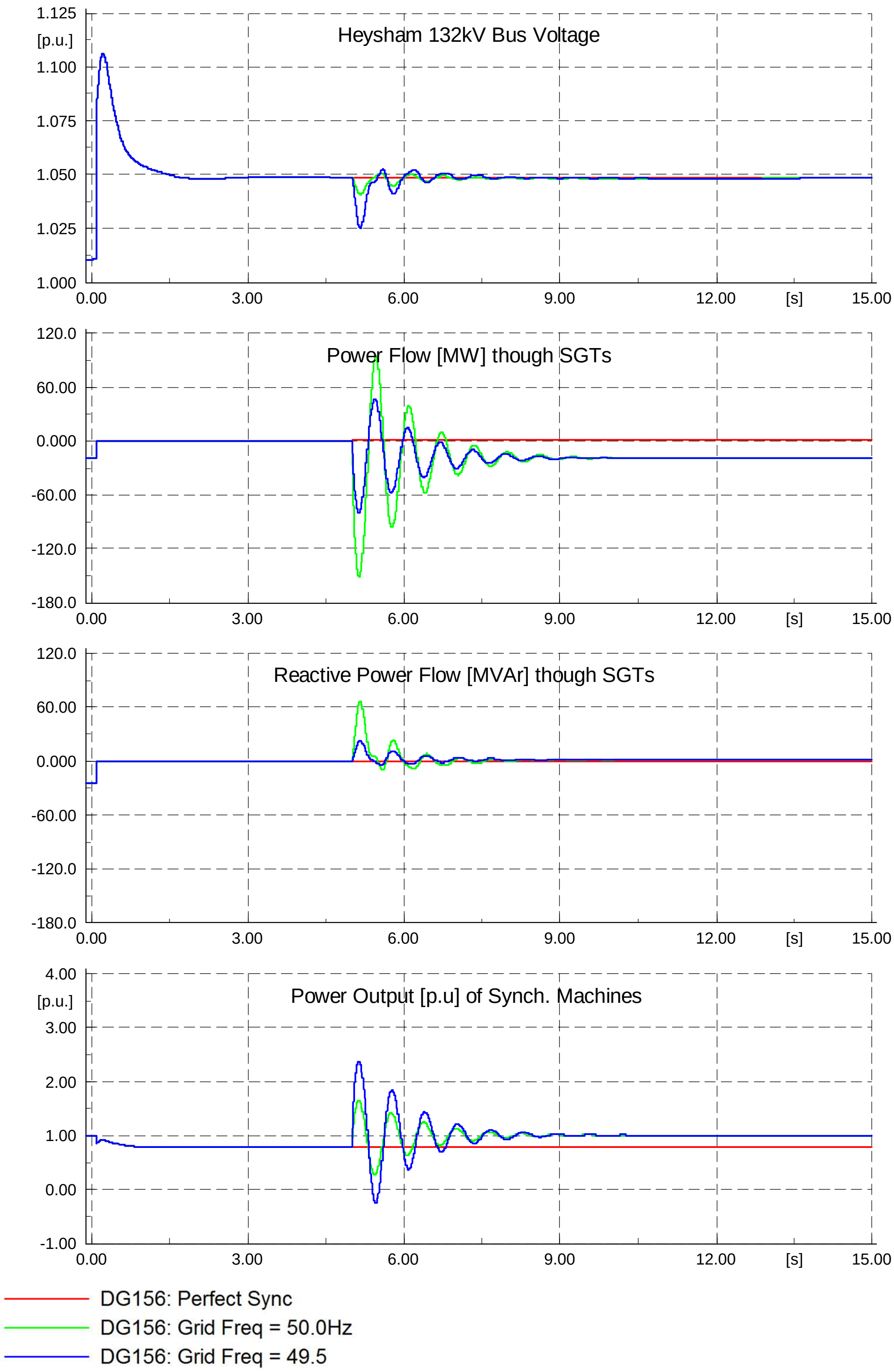
The issues with ensuring these synchronising variables are matched are demonstrated using the model of the Heysham network, with a solid AC voltage source representing the National Grid network. In the demonstration base case, the steady state frequency following the island formation is 50.5 Hz; and the 400kV terminals of the transformers had a voltage of 1.0486 p.u. It is assumed in this example that supergrid transformers were energised from 132kV side). The breaker which reintegrates the island with National Grid closes at simulation time t=5s.

When the synchronising variables quantities are matched, there will be no disturbance to either network. Practically however, it is unlikely that these quantities will match exactly, but the differences can be minimised through control systems.

[Blank space intentional]

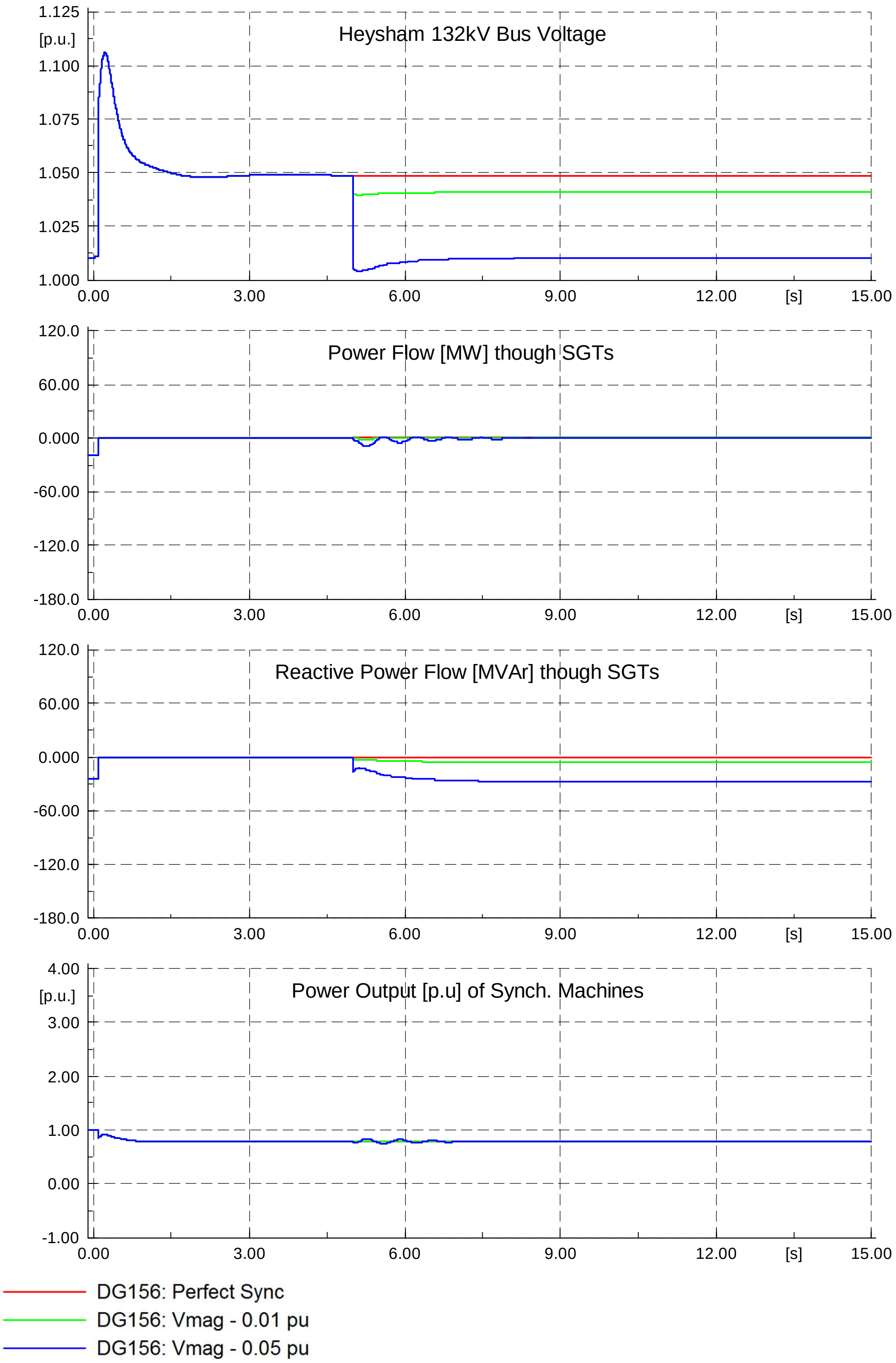
Unequal frequencies on either network, a sudden MW flow will appear across the circuit breaker as it is closed, which is mirrored by an opposing reaction in the embedded synchronous machines. A new common frequency is established, based upon the relative strengths of the two systems. In the case of the Heysham group, it is unlikely to significantly deviate the NG system frequency. As the simulation plot (Figure 25) shows, with the NG frequency at 50 Hz (0.5 Hz deviation), 81.3 MW is initially injected in to the island, settling at 19.5 MW. With NG at 49.5 Hz (1.0 Hz deviation and at statutory limits), this increases to 153.1 MW transiently, but the steady state power draw is the same.

Figure 25 - Frequency Difference



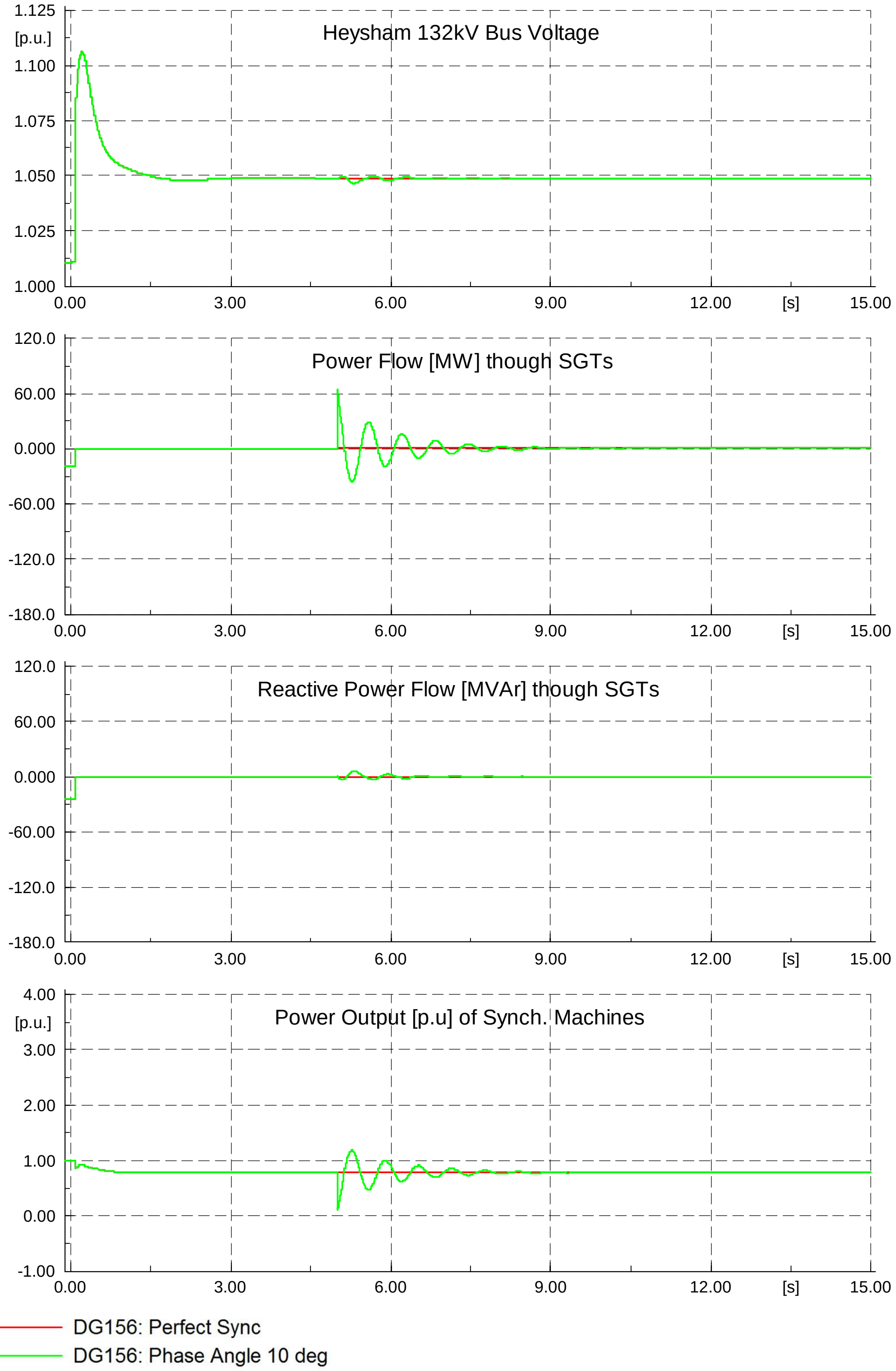
If voltage magnitudes are not closely matched, a sudden rise in MVAr flow will appear across the circuit breaker as it is closed. The Figure 26 below shows the response when the voltage over the closing breaker is 1% and 5% different - NG voltage is lower. The steady state reactive power draw at 1% difference is 5.8 MVAr, and 27.6 MVAr at 5% voltage difference.

Figure 26 - Voltage Magnitude Difference



Phase Angle difference is the time in electrical degrees between the zero crossings on the voltage of the two systems. A phase angle difference will cause a sudden MW flow to appear across the closing circuit breaker. The Figure 27 below shows the response when the phase angle over the closing breaker is 10 degrees different. In this case, a transient power flow, peaking at 60 MW can be seen, before returning to zero in the steady state.

Figure 27 - Phase Angle Difference



The issues with poor synchronisation have been presented. With the correct equipment, they can be practically eliminated.

In an island situation, embedded generation could feasibly control frequency and voltage magnitude, potentially with support from static compensation as required. Frequency could be adjusted to minimise the voltage phase angle difference over waveforms over a closing breaker and the breaker closed.

A synchroscope is a manual device which can be used by to monitor quantities over an open breaker separating two systems. A needle rotates according to frequency difference (slip). A stationary needle will indicate an identical frequency with phase angle difference between two systems. Voltage magnitude over the open breaker can be monitored through VTs. Such a device could exist at power plant, where generation is localised; and where governor and exciter control can be manually controlled.

Synch-check relays are automatic systems which determine if difference in synchronising variables are within defined limits and can close a breaker if so.

In a future system, islands could be formed at any voltage level but they should be designed as such. The location of synchronising equipment and any associated remote communications need to be installed in advance of any island formation. Without such equipment, resynchronising islands is ill-advised.

The other option, though perhaps difficult to swallow, is to manually shut down the island and reenergise from the NG in stages. This is of course an economic decision which must consider CI and CML costs.

Appendix A

GENERATION / DEMAND DATA

Table A-1 – Synchronous Machines

Synchronous Machine	Plant Category	MVA	MW @ 0.85pf
DG177	Gas	60	51
DG156	Gas	45	38.25
DG150	Gas	25	21.25
DG189	Gas	25	21.25
DG3	Others	5.5	4.675
DG9	Others	1.75	1.4875
DG98	Gas	1.5	1.275
DG185_CHP	CHP	1.375	1.16875
Total		**165.1**	**140.4**
Total Large Generation (≥50MW)		**60.0**	**51.0**
Total Medium Generation (≥5MW, <50MW)		**95.0**	**80.75**
Total Small Generation (<5MW)		**10.1**	**8.61**

Table A-2 – Asynchronous Machines

Asynchronous Machine	Plant Category	MVA/MW
DG115	Wind	150
DG78	Wind	100
Barrow_WF	Wind	90
Ormonde_Energy_1	Wind	76
Ormonde_Energy_2	Wind	76
Caton_Moor_WF	Wind	16
DG206	Wind	8
DG141	Wind	4
DG249	Photovoltaic	4
DG46	Photovoltaic	4
DG82	Wind	4
DG208	Wind	2
DG61	Photovoltaic	1.5
Total MVA / MW (rated at unity pf)		**535.5**
Total Large Generation (≥50MW)		**492.0**
Total Medium Generation (≥5MW, <50MW)		**24.0**
Total Small Generation (<5MW)		**19.5**

Table A-3 – Network Loads

Name	Busbar	MW	MVAr	MVA	pf
lancas_11_a Load	lancas_11_a	8.75	0.57	8.77	0.998
lancas_11_b Load	lancas_11_b	8.75	0.57	8.77	0.998
burrow_11_a Load	burrow_11_a	8.43	0.75	8.46	0.996
burrow_11_b Load	burrow_11_b	8.43	0.75	8.46	0.996
westga_6.6_a Load	westga_6.6_a	7.96	1.01	8.03	0.992
westga_6.6_b Load	westga_6.6_b	7.96	1.01	8.03	0.992
wohila_6.6_a Load	wohila_6.6_a	6.97	0.74	7.01	0.994
ALRS Scheme	spgast_6.6_b	5.48	1.80	5.76	0.950
ALRS Scheme(1)	spgast_6.6_a	5.48	1.80	5.76	0.950
broadw_6.6_a Load	broadw_6.6_a	5.55	0.35	5.56	0.998
broadw_6.6_b Load	broadw_6.6_b	5.55	0.35	5.56	0.998
bolesa_11_a Load	bolesa_11_a	5.56	-0.14	5.56	1.000
bolesa_11_b Load	bolesa_11_b	5.56	-0.14	5.56	1.000
spgast_11_c Load	spgast_11_c	5.16	1.00	5.26	0.982
spgast_11_d Load	spgast_11_d	5.16	1.00	5.26	0.982
claugh_11_a Load	claugh_11_a	3.54	0.36	3.56	0.995
Ormonde Energy(4)	ormon_132_tee	2.16	0.00	2.16	1.000
trimpe_11_a Load	trimpe_11_a	1.51	0.50	1.59	0.949
trimpe_11_b Load	trimpe_11_b	1.51	0.50	1.59	0.949
Barrow Offshore Windfarm A Load	baroff_132_gt1	0.80	0.00	0.80	1.000
UUW Quernmore Park	querpk_33_d	0.44	0.19	0.48	0.915
UUW Quernmore Park(1)	querpk_33_c	0.44	0.19	0.48	0.915
Caton Moor IMPORT	catonm_33_t11	0.06	0.20	0.21	0.305
mellis_33_a Load	mellis_33_a	0.20	0.00	0.20	1.000
TP Aspinall	tpaspi_11_a	0.11	0.02	0.11	0.980
Total		**111.5**	**13.4**	**113.0**	**0.987 avg**

Appendix B

MODELLING OF UFLS

UNDER FREQUENCY LOAD SHEDDING MODEL

A multi-stage UFLS scheme for load elements was developed using Digsilent Simulation Language (DSL); this does not require the user to split out loads into chunks (representing feeders) to add relay models or create events.

The functionality of the UFLS model is described below. The statements reference Figures B-1 and B-2 beneath.

1. An instantaneous frequency signal from voltage measurement (StaVmea) element is passed to a custom DSL model;
2. The frequency signal goes through a moving average filter (which has a variable); and scaled by the parameter **fnom**; producing the signal **f_in**.
3. The averaged frequency is compared with the values of parameters **f1…f10** and a scaling factor is selected by DSL logic.
4. The absolute load P,Q for the connected load element is calculated in DSL Logic, and exported as signals **Pext**, **Qext**; which are input in to the load element (ElmLod)
5. The scaling factor is clamped, such that if frequency rises, scaling factor remains at the lowest value previously calculated; this is to simulate tripping of load without reattachment.

Figure B-1 – Block Diagram for UFLS

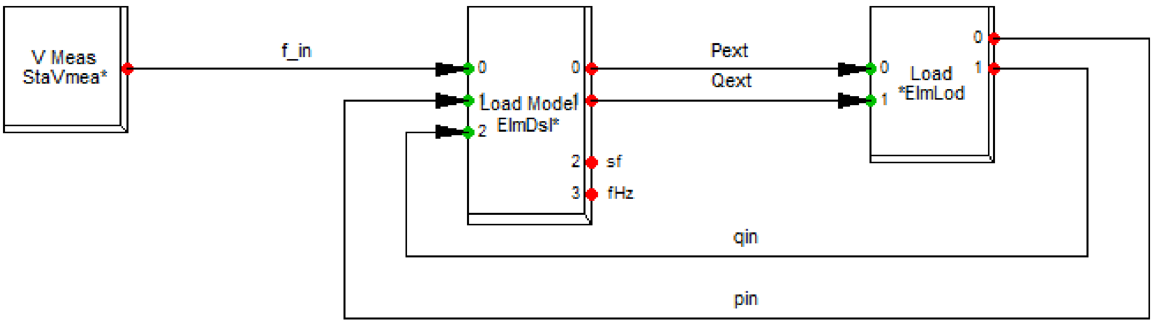


Figure B-2 – Parameters for 5 level UFLS model.

To test the UFLS model, a simple 2-bus network as shown in Figure B-3 was created. In this model, an AVR model is applied to the synchronous machine; but no governor is set. The load is nominally 1MW at unity power factor. The impedance of the circuit is 0.01p.u. on 100 MVA base.

Figure B-3 – Two port network model

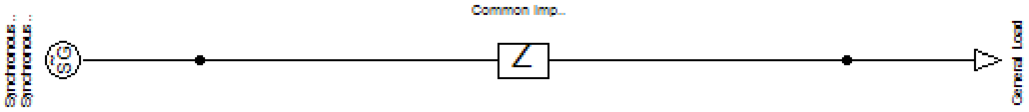
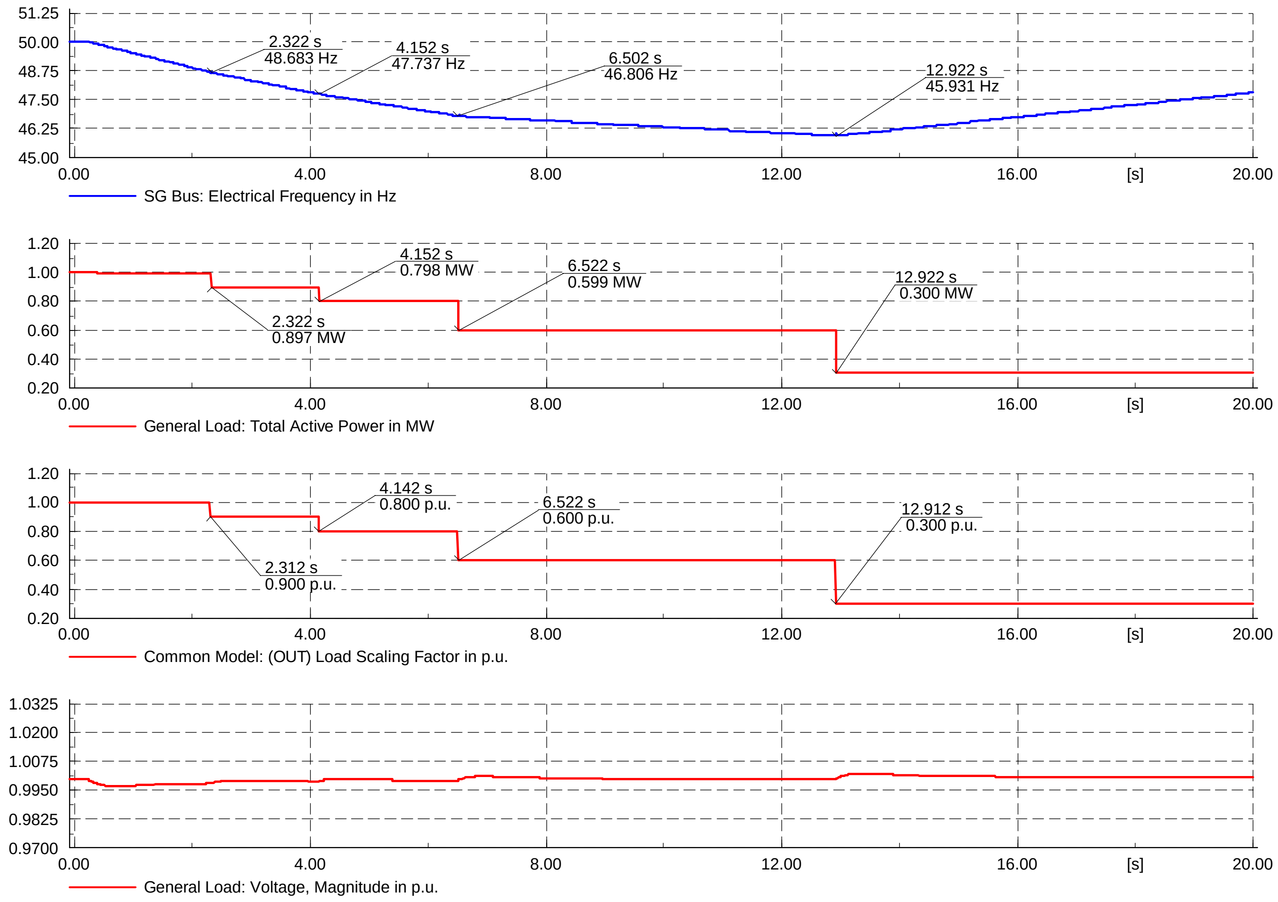


Figure B-4 shows the result of a mechanical power reduction on the synchronous machine. The frequency can be seen to drop from 50Hz; with the UFLS scaling (tripping) the load as expected at all stages; until frequency begins to recover beyond t=13 seconds. As required, the load does not reattach as frequency rises.

Figure B-4 – Mechanical power drop test results



Appendix C

MODELLING OF G59/G99 RELAY

RELAY MODEL DESIGN

A multi module relay which conformed to G59 and G99 was required for this study. The model frame consists of slots for standard relay models and custom logic.

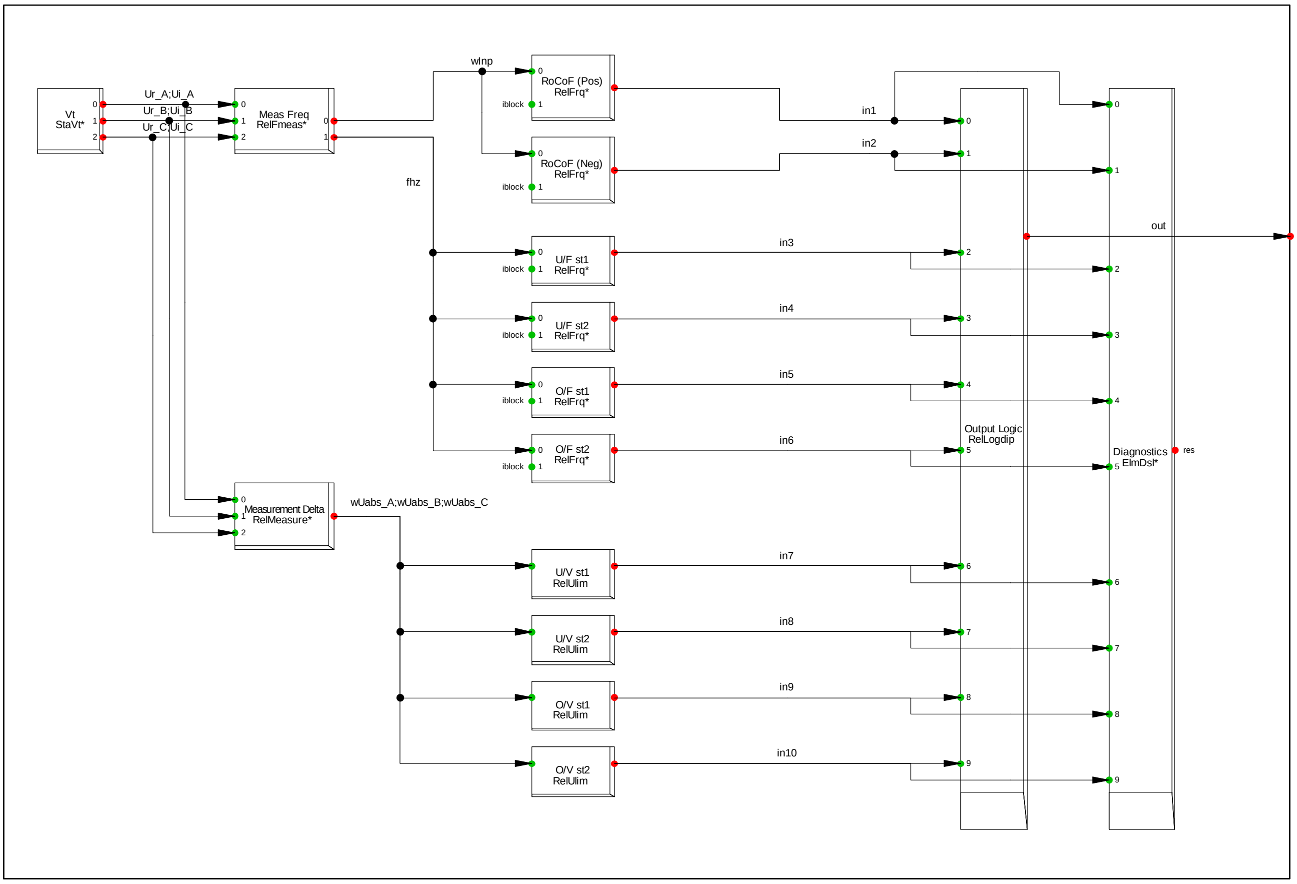
The relay module slots are as follows:

- 2x Gradient (df/dt) with optional time delay (RelFrq)
- 2x Instantaneous over frequency with optional time delay (RelFrq)
- 2x Instantaneous under frequency with optional time delay (RelFrq)
- 2x 3Ph Overvoltage (ANSI 27) with optional time delay (RelUlim)
- 2x 3Ph Undervoltage (ANSI 27) with optional time delay (RelUlim)

The functionality of the relay model frame is described below. The statements reference Figures C-1 beneath.

1. An instantaneous voltage measurement signal from voltage transformer (StaVt) element is passed to two blocks, a Frequency Measurement (RelFmeas) and Voltage Measurement (RelMeasure):
   a. The RelMeasure block converts the voltage signals into relative (per unit) quantities.
   b. The RelFmeas block converts the voltage signal into a frequency signal and applies goes a moving average filter; nominally set to 2 cycles (40ms) window.
2. The processed signals are passed into the standard relay modules, as listed above. If the criteria for tripping is met, the relay module will send a logical 1 as an output, otherwise the output will be a logical 0.
3. The **Output Logic** block is a logical 'AND' block, which produces a binary trip signal as the model output (out) signal; and individual binary signals to the Diagnostic Block
4. The **Diagnostic** block interprets the binary signals from the **Output Logic** block and outputs a text message to the user console upon receipt of a trip signal from one of the inputs so that a user can see the reason why the relay has tripped.

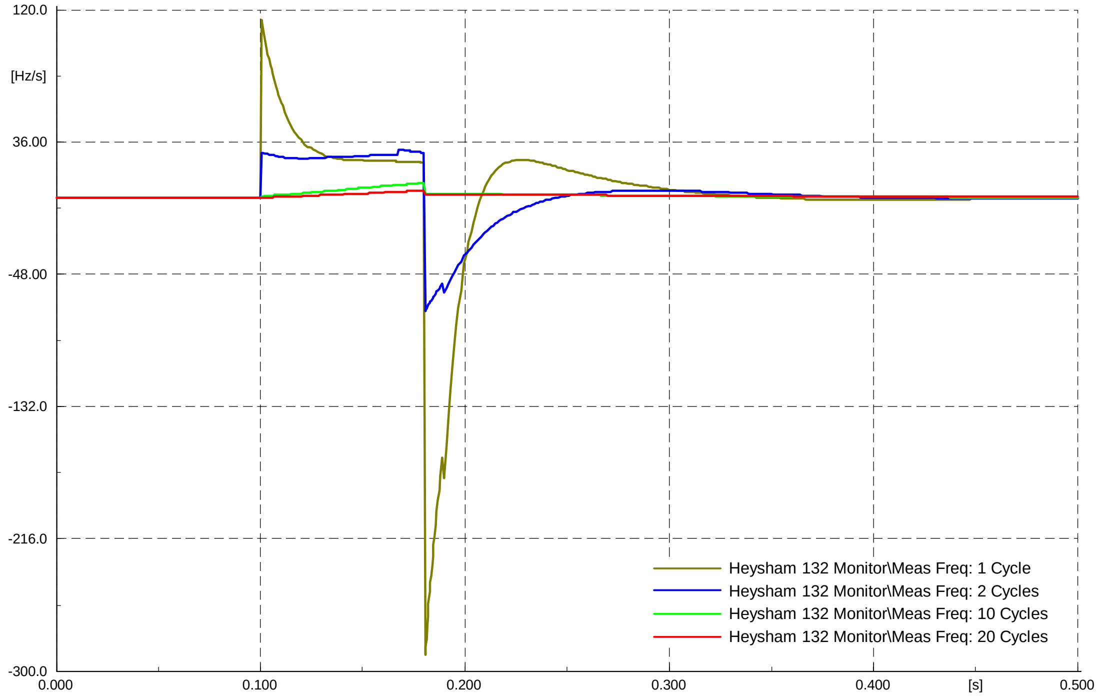
Figure C-1 – Block Diagram

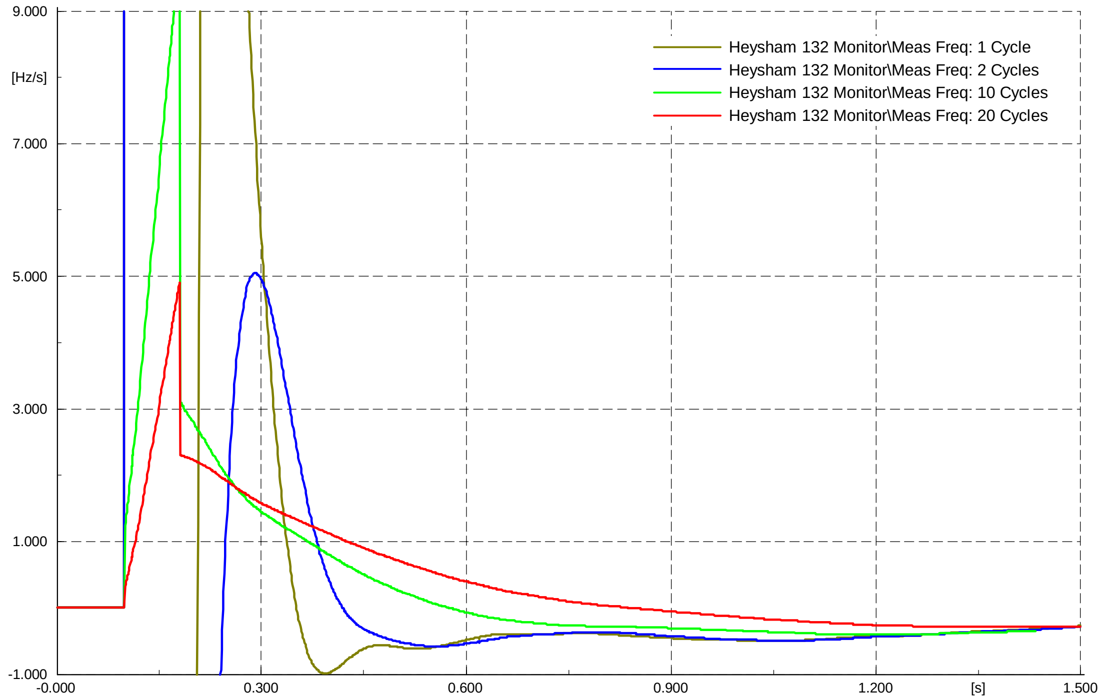


RocoF Moving Average Window

The instantaneous derivative of frequency (or rate of change of frequency / RoCoF) traces from dynamic simulations are sensitive to numerical and topological discontinuities. These occur due to the design of the program and throughout the simulations as events as defined ahead of time, and changes to the network caused by protection relays. Instantaneous RocoF is also sensitive to the simulation time step selected. To reduce the noise seen in simulations, a moving average filter was included on the frequency input signals. As shown in Figure C-3 below, increasing the window size has a smoothing effect, peaks are reduced but the time at which the new peak persists is increased. Eventually the curves converge as the network settles following a disturbance. In this project a default window size of 2 cycles (40ms) was used.

Figure C-3 – RocoF cycles





Appendix D

LOAD SCALING RESULT TABLES

Case		Load	Result	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
				Max	Min	Last	Max	Min	Last	Max	Min	Last
1	High Export G59	80%	FAIL	1.15	0.00		1.11	0.00		53.30	49.00	
2	High Export G59	75%	PASS	1.16	0.87	1.05	1.12	0.84	1.00	53.32	49.15	50.55
3	High Export G59	70%	PASS	1.17	0.87	1.05	1.12	0.84	1.01	53.34	49.25	50.71
4	High Export G59	65%	PASS	1.18	0.86	1.05	1.13	0.85	1.01	53.37	49.33	50.88
5	High Export G59	60%	PASS	1.19	0.86	1.05	1.14	0.85	1.01	53.39	49.35	51.04
6	High Export G59	55%	PASS	1.19	0.86	1.05	1.14	0.85	1.01	53.42	49.38	51.21
7	High Export G59	50%	FAIL	1.20	0.00		1.15	0.00		53.44	49.40	
8	High Export G59 NoDG189	65%	FAIL	1.21	0.00		1.16	0.00		53.58	49.43	
9	High Export G59 NoDG189	60%	PASS	1.22	0.86	1.05	1.17	0.83	1.01	53.61	49.47	50.58
10	High Export G59 NoDG189	55%	PASS	1.23	0.86	1.05	1.18	0.83	1.01	53.63	49.50	50.80
11	High Export G59 NoDG189	50%	FAIL	1.26	0.00		1.18	0.00		53.70	49.50	
12	High Export G99	115%	PASS	1.11	0.86	1.04	1.07	0.83	1.00	53.15	48.62	50.06
13	High Export G99	110%	PASS	1.12	0.86	1.04	1.08	0.83	1.00	53.17	48.69	50.21
14	High Export G99	105%	PASS	1.12	0.84	1.04	1.08	0.84	1.00	53.19	48.82	50.36
15	High Export G99	100%	PASS	1.13	0.83	1.04	1.09	0.84	1.00	53.22	48.88	50.50
16	High Export G99	95%	PASS	1.14	0.84	1.04	1.09	0.84	1.00	53.24	49.00	50.65
17	High Export G99	90%	PASS	1.14	0.87	1.05	1.10	0.84	1.00	53.26	49.12	50.80
18	High Export G99	85%	PASS	1.15	0.87	1.05	1.10	0.84	1.00	53.29	49.17	50.95
19	High Export G99	80%	PASS	1.15	0.87	1.05	1.11	0.84	1.01	53.31	49.30	51.10
20	High Export G99	75%	PASS	1.16	0.87	1.05	1.11	0.84	1.01	53.33	49.36	51.24
21	High Export G99	70%	PASS	1.17	0.87	1.05	1.12	0.84	1.01	53.36	49.38	51.39
22	High Export G99	65%	PASS	1.17	0.87	1.05	1.13	0.85	1.01	53.38	49.41	51.54
23	High Export G99	60%	FAIL	1.18	0.00		1.13	0.00		53.40	47.51	
24	High Export G99 NoDG189	100%	FAIL	1.14	0.00		1.09	0.00		53.40	49.01	
25	High Export G99 NoDG189	95%	PASS	1.14	0.87	1.04	1.10	0.82	1.00	53.42	49.16	50.13
26	High Export G99 NoDG189	90%	PASS	1.15	0.87	1.04	1.11	0.82	1.00	53.45	49.22	50.32
27	High Export G99 NoDG189	85%	PASS	1.16	0.87	1.05	1.12	0.82	1.00	53.47	49.34	50.51
28	High Export G99 NoDG189	80%	PASS	1.17	0.87	1.05	1.12	0.83	1.01	53.50	49.44	50.70
29	High Export G99 NoDG189	75%	PASS	1.18	0.87	1.05	1.13	0.83	1.01	53.53	49.48	50.90
30	High Export G99 NoDG189	70%	PASS	1.19	0.87	1.05	1.14	0.83	1.01	53.55	49.51	51.09
31	High Export G99 NoDG189	65%	PASS	1.20	0.87	1.05	1.15	0.83	1.01	53.58	49.54	51.28
32	High Export G99 NoDG189	60%	PASS	1.21	0.87	1.05	1.16	0.83	1.01	53.60	49.57	51.48
33	High Export G99 NoDG189	55%	FAIL	1.30	0.00		1.26	0.00		53.63	48.08	
34	High Export G99 NoDG189+150	80%	FAIL	1.19	0.00		1.15	0.00		53.79	49.36	
35	High Export G99 NoDG189+150	75%	PASS	1.21	0.83	1.05	1.16	0.81	1.01	53.82	49.65	50.18
36	High Export G99 NoDG189+150	70%	PASS	1.23	0.83	1.07	1.18	0.82	1.02	53.85	49.70	49.93
37	High Export G99 NoDG189+150	65%	FAIL	1.48	0.00		1.42	0.00		53.87	45.99	
38	Low Renewables G59	75%	FAIL	1.16	1.01		1.09	1.00		50.89	49.07	
39	Low Renewables G59	70%	PASS	1.17	1.01	1.07	1.10	1.00	1.00	50.92	49.73	50.12
40	Low Renewables G59	65%	PASS	1.18	1.01	1.07	1.11	1.00	1.00	50.96	49.78	50.29
41	Low Renewables G59	60%	PASS	1.18	1.01	1.07	1.11	1.00	1.00	50.99	49.83	50.45

Case		Load	Result	132 Volt (p.u)			33 Volt (p.u)			Frequency (Hz)		
				Max	Min	Last	Max	Min	Last	Max	Min	Last
42	Low Renewables G59	55%	PASS	1.19	1.01	1.07	1.12	1.00	1.01	51.02	49.87	50.61
43	Low Renewables G59	50%	FAIL	1.20	0.00		1.13	0.00		51.05	48.93	
44	Low Renewables G99	90%	FAIL	1.12	1.00		1.08	1.01		50.83	49.42	
45	Low Renewables G99	85%	PASS	1.15	1.01	1.07	1.08	1.00	1.00	50.87	49.71	50.08
46	Low Renewables G99	80%	PASS	1.15	1.01	1.07	1.08	1.00	1.00	50.90	49.76	50.23
47	Low Renewables G99	75%	PASS	1.16	1.01	1.07	1.09	1.00	1.00	50.93	49.80	50.38
48	Low Renewables G99	70%	PASS	1.16	1.01	1.07	1.09	1.00	1.00	50.96	49.84	50.52
49	Low Renewables G99	65%	PASS	1.17	1.01	1.07	1.10	1.00	1.00	50.99	49.89	50.67
50	Low Renewables G99	60%	PASS	1.17	1.01	1.07	1.10	1.00	1.01	51.09	49.93	50.82
51	Low Renewables G99	55%	PASS	1.18	1.01	1.07	1.11	1.00	1.01	51.15	49.97	50.81
52	Low Renewables G99	50%	PASS	1.18	1.01	1.07	1.11	1.00	1.01	51.33	50.00	50.97
53	Low Renewables G99	45%	PASS	1.19	1.01	1.07	1.12	1.00	1.01	51.55	50.00	51.13
54	Low Renewables G99	40%	PASS	1.20	1.01	1.08	1.12	1.01	1.01	51.72	50.00	51.23
55	Low Renewables G99	35%	FAIL	1.71	0.00		1.57	0.00		96.27	0.56	
56	Low Renewables G99 + UFLS	90%	PASS	1.13	1.00	1.06	1.08	1.01	1.01	50.81	49.38	49.38
57	Low Renewables G99 + UFLS	95%	PASS	1.13	1.00	1.06	1.07	1.00	1.01	50.78	48.59	50.31
58	Low Renewables G99 + UFLS	100%	PASS	1.12	1.00	1.06	1.07	1.00	1.01	50.75	48.41	50.37
59	Low Renewables G99 + UFLS	105%	FAIL	1.12	0.00		1.07	0.00		50.72	45.99	
60	Low Import Case G99	100%	PASS	1.10	1.01	1.05	1.05	1.00	1.00	50.02	49.79	49.98
61	Low Import Case G99	105%	PASS	1.09	1.01	1.05	1.05	1.00	1.00	50.00	49.64	49.83
62	Low Import Case G99	110%	FAIL	1.09	1.01		1.04	1.00		50.00	48.80	
63	Low Import Case G99 + UFLS	100%	PASS	1.10	1.01	1.05	1.05	1.00	1.00	50.02	49.79	49.98
64	Low Import Case G99 + UFLS	105%	PASS	1.09	1.01	1.05	1.05	1.00	1.00	50.00	49.64	49.83
65	Low Import Case G99 + UFLS	110%	PASS	1.09	1.01	1.05	1.04	1.00	1.00	50.00	48.80	48.80
66	Low Import Case G99 + UFLS	115%	PASS	1.09	1.01	1.05	1.04	1.00	1.00	50.26	48.59	50.11
67	Low Import Case G99 + UFLS	120%	PASS	1.08	1.01	1.05	1.04	1.00	1.00	50.35	48.41	50.18
68	Low Import Case G99 + UFLS	125%	FAIL	1.08	0.00		1.03	0.00		50.86	46.81	
69	High Export G99 + UFLS	100%	PASS	1.13	0.83	1.04	1.09	0.84	1.00	53.22	48.88	50.50
70	High Export G99 + UFLS	105%	PASS	1.12	0.84	1.04	1.08	0.84	1.00	53.19	48.82	50.36
71	High Export G99 + UFLS	110%	PASS	1.12	0.86	1.04	1.08	0.83	1.00	53.17	48.69	50.21
72	High Export G99 + UFLS	115%	PASS	1.11	0.86	1.04	1.07	0.83	1.00	53.15	48.62	50.06
73	High Export G99 + UFLS	120%	FAIL	1.11	0.00	0.00	1.07	0.00	0.00	53.12	48.51	50.00
74	High Export G99 + UFLS	125%	FAIL	1.08	0.00	0.00	1.06	0.00	0.00	53.07	48.46	50.00
75	High Export G99 + UFLS	130%	FAIL	1.08	0.00	0.00	1.06	0.00	0.00	53.04	48.46	50.00
76	High Export G99 + UFLS	135%	FAIL	1.07	0.00	0.00	1.05	0.00	0.00	53.02	48.36	50.00
77	High Export G99 + UFLS	140%	FAIL	1.07	0.00	0.00	1.04	0.00	0.00	53.00	48.22	50.00
78	High Export G99 + UFLS	145%	FAIL	1.06	0.00	0.00	1.04	0.00	0.00	52.97	48.15	50.00
79	High Export G99 + UFLS	150%	FAIL	1.06	0.00	0.00	1.03	0.00	0.00	52.95	48.01	50.00

Amber Court
William Armstrong Drive
Newcastle upon Tyne
NE4 7YQ

wsp.com