Network Innovation Competition: Enhanced Frequency Control Capability (NIC EFCC)

Manchester RTDS HiL-testing to assess the entire monitoring and control system for EFCC

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Executive Summary

This document is prepared in order to test the functionality of the entire Monitoring and Control System (MCS) using GB equivalent RTDS model by hardware-in-the-loop test, implemented on the hardware platform using the PLC environment.

The functionality of each of the AFBs has been validated in the previous report. The main functionality of event detection AFB and resource allocation AFB as well as entire MCS is validated in this report using GB network test system model with testing the entire MCS.

A representative Real Time Digital Simulation (RTDS) model of the GB transmission system used to test the operation of the GE MCS and its associated architecture is constructed, considering dynamic load and generation models representing those resources upon the GB transmission system and embedded within the distribution networks. In addition, the above-mentioned model is configured to conditions reflective of future transmission system levels of inertia, generation technology and demand type.

A hardware interface using industry standard communication protocol with which to enable the input and output to the MCS controller as well as time synchronization using GPS signals is developed, providing Hardware-in-the-Loop (HiL) testing facilities for the tests performed in this report.

With proper test system and complete of HiL testing facilities, the scenarios of generation loss, demand loss, fault event, switching event, fault and generation loss, and a variety of different variety of fault type are investigated. The MCS performs as expected and robustly. We have noted that the effect of disturbances is seen differently in relation to the location and proximity to PMUs used for the MCS. This indicates that both the scope of PMU deployment and the method for determining proper weightings for PMU measurements within the MCS would need further review ahead of implementation.

The tests presented in this report has illustrated the potential benefits for de-risking and understanding in detail the operation and potential benefits of innovative wide-area power system monitoring and control schemes such as EFCC through the use of “Hardware-in-the-loop” based testing facilities.

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Acronyms

AFB	Application Function Block
CS	Central Supervisor
LC	Local Controller
NG	National Grid
MCS	Monitoring and Control System
MMC	Modular Multilevel Converter
PhC	PhasorController
PLC	Programmable logic controller
PMU	Phasor Measurement Unit
RA	Regional Aggregator
RoCoF	Rate of Change of Frequency
SAT	Site acceptance test
UoM	University of Manchester
WAMS	Wide-Area monitoring Scheme

1 Introduction

This report presents the results and performance of the Enhanced Frequency Control Capability (EFCC) scheme, using representation model of the future lower inertia GB system simulated by a Real Time Digital Simulator (RTDS) based Hardware-in-Loop (HiL) testing facility.

The focus of the report is to assess the performance of the equipment of GE's Monitoring and Control Scheme (MCS) and to report its success or issues across a series of defined tests of typical power system disturbance conditions. The RTDS simulation environment has been dispatched to capture typical future transmission system performance against scenarios as defined within National Grids Future Energy Scenarios (FES).

The Monitor and Control Scheme has been developed by GE with three kinds of controllers: Local Controller (LC), Regional Aggregator (RA) and Central Supervisor (CS). A total 4 LCs, 2 RAs and 1 CS are handed to the University of Manchester. Within each controller, several functions are performed upon the data received via Application Function Blocks (AFB). Then site acceptance test (SAT) which test initial installation and configuration is accomplished by GE and UoM in Manchester RTDS lab.

Following SAT, HiL Validation tests of each Application Function Block (AFB) of the LC, RA, CS are conducted to verify the individual functionality. The test result and performance assessment are reported in the previous report “HiL Validation of EFCC AFBs”.

After individual functionality of AFBs tested and passed, entire MCS as well as event detection AFB and resource allocation AFB are tested using the 26-bus future GB network test system.

A review of MCS and some important AFC and settings are briefly described first. Then the background information of Manchester RTDS facility and modelling of the test system are introduced.

Next, testing method, objectives and how test is actually executed are described. In the next section, the test results, outcomes and limitation are presented and discussed.

Finally, an overview of the test results and learning outcomes are concluded followed by future work suggestions based on findings.

1.1 Monitoring and Control Scheme

For a better understanding of the test presented in the report, GE MCS is briefly described in the following section. A more detailed overview of the EFCC architecture and various other operational aspects of the system are available in [1] - [4].

Monitoring element of the scheme

The first part of the monitoring scheme is capturing the data in the regional PMUs through their connected CTs and VTs. The data is sent from the regional PMUs to the RAs. On the RA, there are a number of functions shown:

1. Time Synchronisation

   Provides time alignment functionality of the individual PMU streams, equivalent to a Phasor Data Concentrator (PDC) with a suitable low wait time for delayed packets to arrive. Lower wait time for control compared to monitoring applications.

2. Regional Aggregation of Frequency and Angle

   Based on weighted averaging, using inertia weights that are assigned by the user for each PMU to provide a frequency and angle measurement equivalent to the centre of inertia of the region.

3. Fault Detection

   If a fault is detected on any of the connected PMUs, the RA will output a fault detected flag. The detection of a fault will be based on thresholding of the voltage magnitude on the individual PMU measurements. The fault detection is necessary to block event detection during fault-on periods to avoid detection based on fault conditions.

4. Dead Line Detection

   If a line is dead (e.g. disconnected) the voltage level may be below the threshold. To avoid dead (de-energised) lines being identified as faults, an algorithm will determine if the voltage is fault level or dead. If the PMU is sending a signal from a 'dead' line, the frequency and angle information or not relevant and are neglected from the aggregation function.

The data from the RA will be a single frequency and angle value, equivalent to the centre of inertia of the region sent in a single IEEE C37.118 frame, along with fault detected signals and signal quality information.

Each of the LCs is also involved in the monitoring stage. Each LC must be configured with several details (including voltage thresholds for fault detection, frequency and RoCoF for event detection and inertia levels). The information from each RA is communicated over a WAN where each LC receives the outputs from each of the RAs. In a system with *n* regions, the LC will receive n aggregated frequency and angle values. On the LC, there are a number of functions related to the different applications. The data from the wide area must firstly be consolidated, plus the additional PMU stream from the local PMU must be captured. The data is then sent to the Event Detection AFB for processing. The functions on the LC from the monitoring point of view are:

1. Confidence Level Check for Frequency and Angle

For each incoming stream, the LC will determine if the data in that stream sufficiently represents the behaviour of that region, i.e. the % visibility of the region which is based on valid data from the originating PMUs.

2. Fault Detection

   As with the RA, fault detection is applied to the local PMU signal, too.

3. System Aggregation Frequency and Angle

   This has the same basic functionality as described for the RA, however in this case it aggregates the regional aggregates using user defined inertia weights for each region to form an equivalent system frequency and angle, equivalent to the centre of inertia of the entire power system.

4. Selection of Local/Regional Aggregated Frequency/Angle

   Depending on the quality of the aggregated signals, it may be necessary to use local signals if the wide-area signal is of poor quality. In this case, the LC would use the last known update from the CS and provide a proportional response based upon this last update.

5. Event Detection

   We assume that an *event* is a sudden mismatch between generated and consumed active power, what results in sudden frequency excursions around its nominal value. The event detection block takes either the system or local frequency as an input, including the fault detected flags. If a fault is detected, the detection is supressed until the fault is cleared. By analysing the RoCoF signal, the block will determine if a frequency event has occurred in the system or not. It will also calculate a RoCoF value which is used later for resource deployment in order to characterise the event magnitude.

   The block will also select a pre-event set of angles for the system (from each region and the system)

These functions complete the ***monitoring element of the scheme***.

Resource Allocation and Fast Response

This role describes the ***control element of the scheme***. The resource allocation function is mainly confined to the LC. Parts of the resource allocation occur on the CS in terms of the portfolio management which is communicated to the LC at either periodic intervals or upon report of a change. If an event is detected, the update from the CS is held at the most recent update. The real-time control is all performed on the LC itself autonomously. The interaction here is between the LC and the resource (or resource customer-side controller). The following functions make up the LC control elements:

1. Define Response

   Using the RoCoF output from the Event Detection AFB, the size of the event is approximated based on the RoCoF and the user-defined estimate of system inertia. The size of the event is used to create a target response value from the system.

This system target response is then spread between the regions according to the post event angular trajectory with more response assigned to regions which see the largest angular movement in relation to the event. This local target response required from each LC is then determined from the regional target response based on a priority ranking function.

2. Initiate Response

   When each LC has determined an appropriate response from its connected resource it will initiate that response by sending an appropriate signal to the partner resource. Due to the number of potential resources, there are a variety of protocols potentially required which will be investigated and tested throughout the project.

3. Monitor Response

   When the LC has initiated response, it will monitor the effects on the frequency and will determine if more response is required. If more response is required, it will determine how much extra power to deploy to bring the df/dt to zero.

When the signal is received by the resource, or the resource customer-side controller, it will convert this request into physical action on the hardware to deliver the fast frequency response.

To assess the above wide area functions it is necessary to construct a wide area representation of the transmission system where frequency readings from virtual or physical PMUs can be injected into the MCS system as they register the effects of a simulated network distortion on that transmission system. This allows us to simulate the effect of disturbances on a future system with lower inertia and different distributions of resources to today in terms of how that changes the measurements of frequency, df/dt and phase angle change that the MCS sees in the HiL. It then allows us to see how the MCS is able to respond to that information across each of the above functions. To this end we have defined a number of key power system disturbance conditions against which the performance of the MCS and the results and conclusion from those results are presented in this report.

2 HiL test environment and GB network test system modelling in RTDS

2.1 Real Time Digital Simulator and Hardware-in the-loop simulation

The Manchester Real-time Digital Simulator (RTDS), including 6 racks with 30 PB5 Processor Cards and 5 Modular Multilevel Converter (MMC) support units is the largest university-based hardware in the loop simulator in the UK and the second largest in Europe. The Manchester RTDS is a digital system which is able to perform electromechanical and electromagnetic electric power system transient simulations continuously in real-time, covering the frequency range DC to ~3kHz. It is designed for hardware in the loop testing of physical equipment such as control and protection devices, or complex solutions involving a large number of intelligent Electronic Devices, shown in Figure 2-1.

The simulator is equipped with sufficient analogue and digital input and output facilities as well as high level communication capabilities (e.g. IEC 61850, C37.118 and IEC 60870). This is particularly important for the development and validation of future Smart Transmission and Distribution Grid applications.

The Manchester RTDS simulator is capable to model simultaneously in one circuit the following minimum list of elements:

- 2100 single-phase nodes,
- 200 traveling wave transmission lines models with three coupled conductors
- 40 synchronous generators,
- 55 two-winding transformers,
- 15 three-winding transformers,
- a 5 terminal MMC-based DC grid, including 5 DC lines,
- controls for the DC grid, generators (exciter, governor/turbine and power system stabilizer), breakers, faults,

RSCAD is the main software used in the RTDS simulator. It provides the ability to set up simulations, control, and modify system parameters during a simulation, data acquisition, and result analysis.

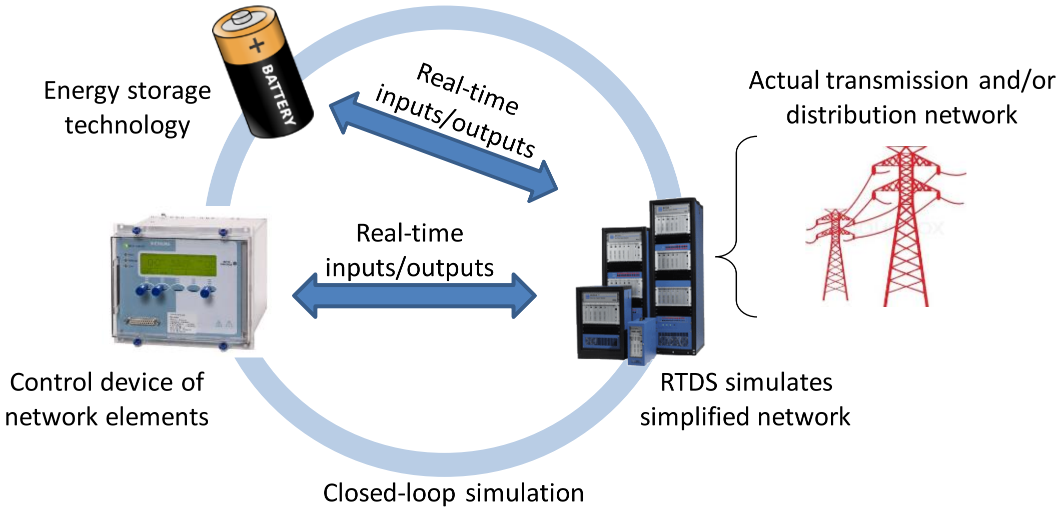

Figure 2-1 ***Block diagram of the Manchester RTDS***

2.2 GB network test system modelling in RTDS

This test uses a GB network test system that is designed to be representative of the GB system. The reduced number of zones (compared to the 36 zone) will allow the incorporation of more complex resource models. By this, the limitations of the Manchester RTDS HiL testing facilities are considered. The facilities are one of the very best in the UK, but each such test system has its limitations when it comes to the complexity of the test system. Each zone will have a different generation mix and certain significant resources (e.g. large offshore wind farms or new nuclear plants) will appear as distinct entities connected to sub networks within the zone.

The reduced model of 36-zone GB network system is simulated in RTDS with 26 buses. In this report, GB network test system model consists of 20 synchronous generators and 25 asynchronously connected generations (inverter-based generation) with 26 lumped loads is selected for EFCC validation and HiL testing, as presented in Figure 2-2. In this model, 4 different types of service providers are also modelled and integrated. Photovoltaic (PV), Doubly Fed Induction Generator (DFIG), Combined Cycle Gas Turbine (CCGT) and Demand Side Response (DSR) are connected in buses 4, 20, 25 and 9, respectively. The nominal voltage of transmission lines is 400 kV, in this network.

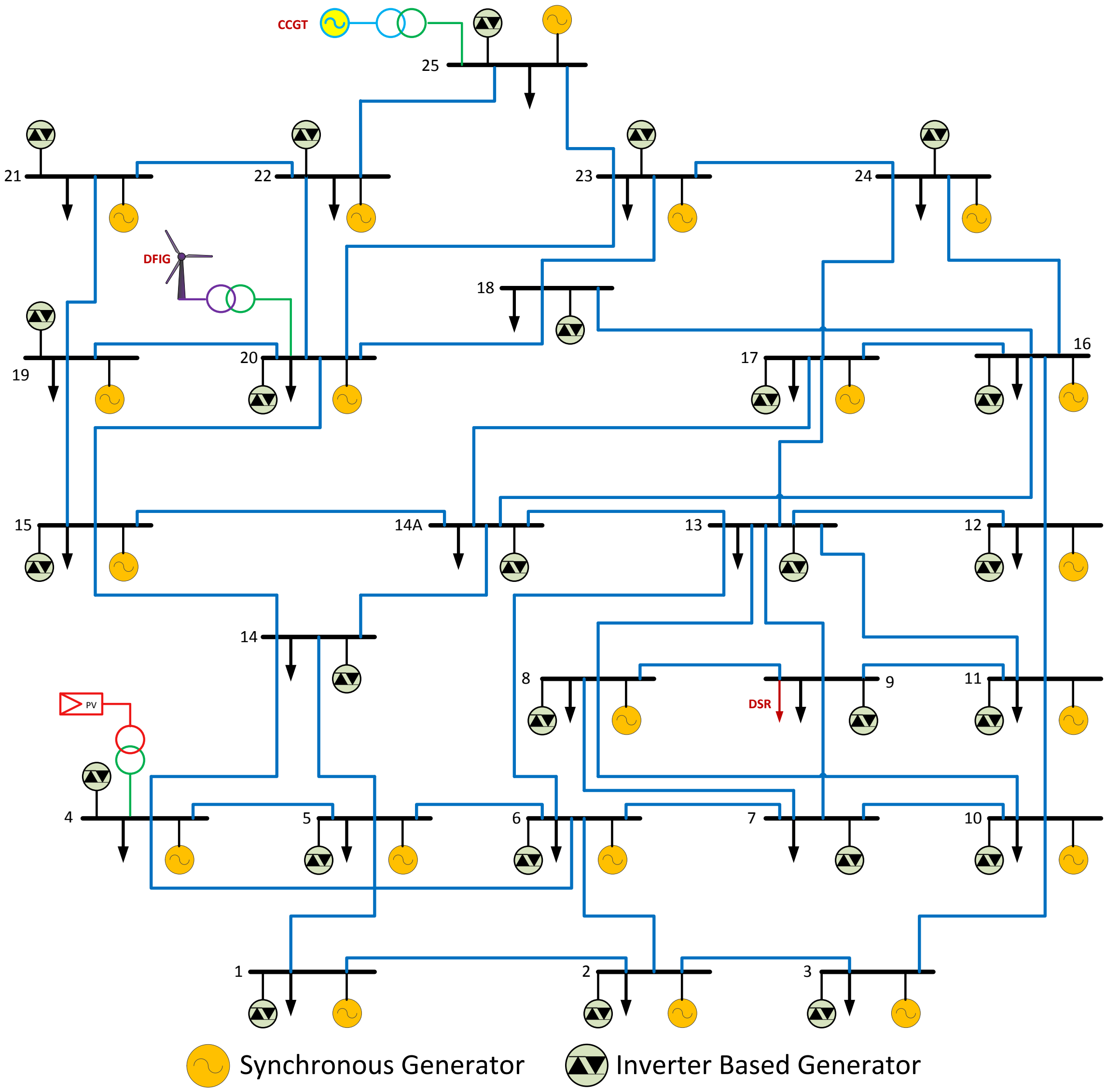

Figure 2-2: Single line diagram model of GB network test system

2.3 System inertia calculation

UK's energy system is undergoing a transformation, with integration more renewable energy sources such as PV, Battery and wind farm to the network. In the past, UK's energy was supplied by large power stations with higher level of inertia due to large rotating masses in the form of turbines and generators' rotors.

In contrast, renewable energy sources are not providing inertia for the power system because they do not have any moving parts. Hence, integration of renewable energy sources will cause to reduce system inertia. System inertia is one of the important parameters for utilities because it acts as a buffer to smooth the effect of fluctuations in frequency. Therefore, a sudden drop in system frequency can cause stability problems in low inertia power system.

In EFCC project, total system inertia is an important parameter in MCS to calculate the imbalance power. System inertia value is used for the estimate of the event size along with the RoCoF value. Power imbalance, *ΔP*, will be calculated based on equation (2) which is presented below:

$$\Delta P = 2 \times K_{TotSysIner} \times \frac{df}{dt} \tag{2}$$

Where: $\frac{df}{dt}$ is rate of change of frequency. $K_{TotSysIner}$ is total system inertia in GE's MCS and it needs to be set in central supervisor by user by single variable named "**TotSysIner**". Instead of using H, K is used because this parameter is not only reflecting the system inertia but a more complex number reflecting the kinetic energy and nominal frequency of the system.

For validation of entire MCS, GB network test system model which is simulated in RTDS is used. The test system model is configured to conditions reflective of future transmission system levels in the year 2020 of inertia including generator inertia and inertia from demand and all other kind of components which have kinetic energy, and generation technology and demand type, referred as "H2020" in the report. Equation (3) is used in the test to calculate the total inertia of the system.

$$K_{TotSysIner} = \frac{\sum_{i=1}^{n} \left(H_{SG}^{i} S_{SG}^{i} \right)}{f_0} \tag{3}$$

where H_{SG}^{i} is the inertia time constant of number i generator, S_{SG}^{i} is the capacity of number i generator and f_0 is the nominal system frequency. It is noteworthy that H_{SG}^{i} has represent inertia of generation and demand. In practice, the inertia of each generator and demand in the system should be always considered. A total value of inertia of the whole system obtained from various estimation method can be used. Total rated power of synchronous generators in GB network test system model in MVA is 31045 MVA (CCGT capacity is also included). In Table 1, the inertia of each zone is shown as a percentage of the total system inertia.

System inertia parameter "TotSysIner" used to set MCS for the H2020 scenario would be equal to 1600 MVA.s/Hz.

Table 1: Calculating system inertia for GB test system, scenario H2020

Region	Name (Syn Gen)	H (%)
1	**Z1**	13.72%
	Z2	2.68%
	Z3	2.88%
	Z4	4.97%

	Z5	3.28%
	Z6	3.47%
	Z8	4.99%
	Z10	6.07%
	Z11	1.12%
	Z12	11.13%
2	CCGT	2.99%
	Z15	3.63%
	Z16	2.81%
	Z17	1.65%
	Z19	2.02%
	Z20	3.83%
	Z21	1.84%
	Z22	3.58%
	Z23	3.71%
	Z24	3.18%
	ZScot25	16.43%

2.4 Virtual PMUs placement and PMU's weight calculation

The aggregation of input signals (PMU frequency and angle) is based on the weightings applied to each input signal as defined by the user. So it is vital important to set the weightings in order to obtain the best possible aggregated system frequency and angle for the scheme.

In the test, Virtual PMU of RTDS, simulated PMU by RTDS, is used to measure the voltages and currents and provide the IEEE C37.118 stream for EFCC Monitoring and Control System (MCS). Virtual PMU of RTDS has been configured and connected with GE's PhasorController (PhC) and explained below.

2.4.1 PMUs placement in GB network

Virtual PMUs which are configured with Regional Aggregators (RAs) are presented in Table 2. In this table, The RA which PMU connected, and bus number which PMU installed are presented. PMUs 1, 2, 3, and 4 are mapped with RA1 and PMUs 5, 6, 7, and 8 are mapped with RA2. PMUs configurations with RAs for GB network test system are illustrated in Figure 2-3.

Table 2: PMUs' setting for mapping with RAs

PMUs setting for mapping with *PhasorControllers* in Straton			
No.	Virtual PMU	Connect to	Bus number
1	PMU1Z11	RA1	1
2	PMU1Z12	RA1	12
3	PMU1Z13	RA1	10
4	PMU1Z14	RA1	4
5	PMU1Z21	RA2	16
6	PMU1Z22	RA2	19
7	PMU1Z23	RA2	23
8	PMU1Z24	RA2	25

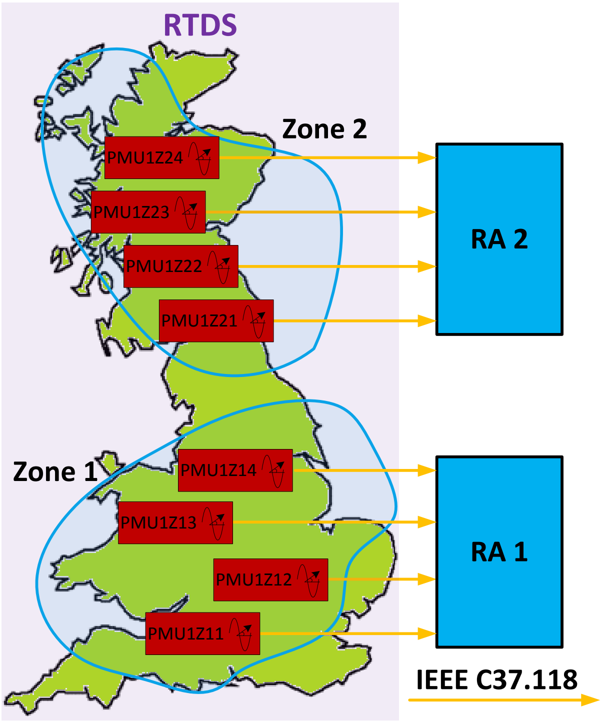

Figure 2-3: PMUs configuration with RAs

Virtual PMUs which are configured with PhasorPoint are also demonstrated in Table 3. GE PhasorPoint is the Phasor Data Concentrator (PDC) and it has been designed for Wide Area Monitoring System (WAMS) and phasor applications solution for system operators and transmission companies. In the test, PhasorPoint is used for recording the test data from all PhasorControllers and virtual PMUs.

Table 3: PMUs' setting for mapping with PhasorPoint

PMUs setting for mapping with *PhasorPoint*		
No.	PMU name	Bus number
1	PMU2Z11	1
2	PMU2Z12	12
3	PMU2Z13	10
4	PMU2Z14	4
5	PMU2Z21	16
6	PMU2Z22	19
7	PMU2Z23	23
8	PMU2Z24	25

PMUs configurations with PhasorPoint for GB network test system are illustrated in Figure 2-4.

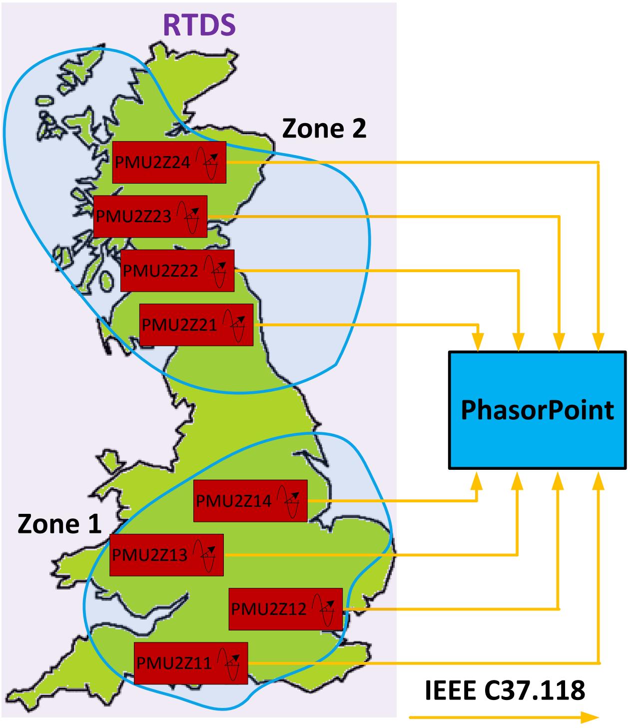

Figure 2-4: PMUs configuration with PhasorPoint

In GE's MCS, LCs need to be connected with local PMU and they will use local PMUs information of service providers. Local PMUs configurations and setting with LCs are additionally presented in Table 4.

Table 4: PMUs' setting for mapping with LCs

PMUs setting for mapping with *PhasorControllers*			
No.	Virtual PMU	Connect to	Bus number
1	LocPMU1	LC 3 (PV)	4
2	LocPMU2	LC 2 (DSR)	9
3	LocPMU3	LC 4 (Wind)	20
4	LocPMU4	LC 1 (CCGT)	25

Local PMUs configurations with LCs for different type of service providers in the GB network test system are illustrated in Figure 2-5.

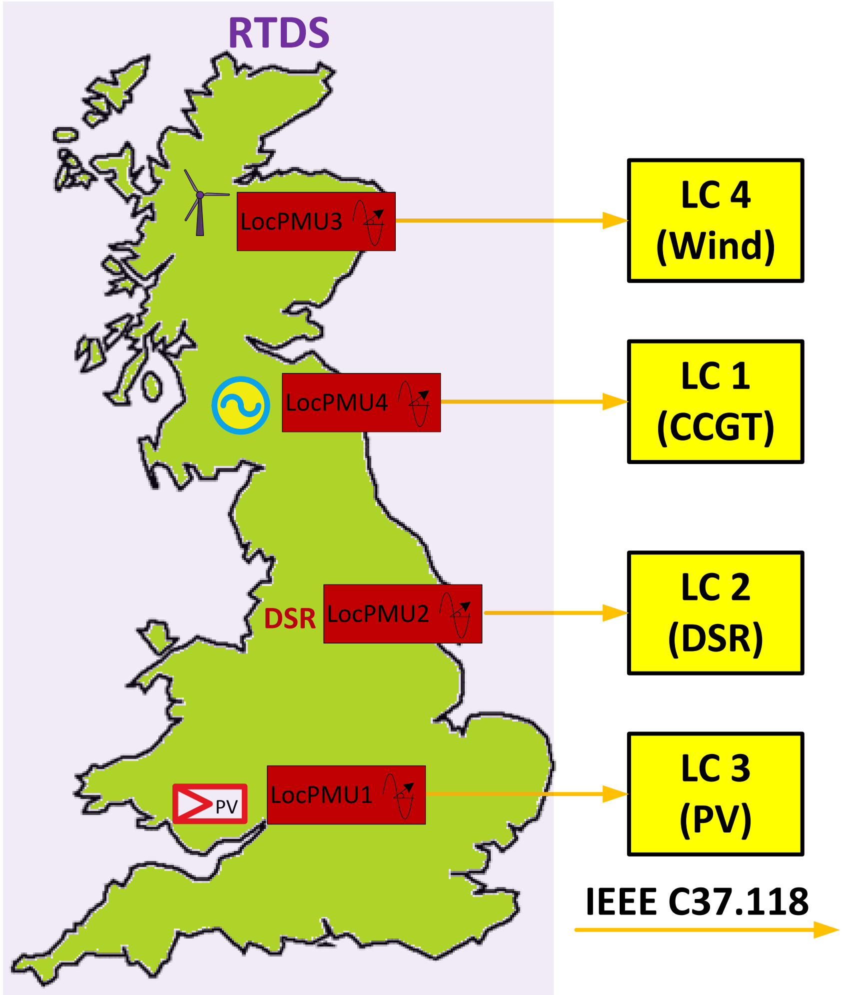

Figure 2-5: Local PMUs configuration with LCs

2.4.2 PMU's weight calculation

Table 5 is illustrated PMUs' weights for all buses in Region 1 of GB test system. Rated power of synchronously connected generation in each bus is lumped and illustrated in this table. Inertia constant of synchronous generators (in second) at each bus is also presented. Then, PMUs' weights calculated according to equation (1) and presented in the form of percentage of total inertia of that region.

As there is no defined equation or method to weight the PMUs in the scheme, therefore following equation for the calculation of PMUs' weights is proposed for GB system model, by calculating a ratio between individual generator inertia and the regional inertia:

$$Weight_{PMU}^{i} = \frac{H_{SG}^{i} S_{SG}^{i}}{H_{region}} \tag{1}$$

Where: H^i_{SG} is inertia constant of synchronously connected generation at bus i; S^i_{SG} is rated power of synchronously connected generation at bus i; H_{region} is total inertia constant of synchronously connected generations into Region 1.

Table 5: PMUs' weights calculation for region 1 in GB system model

Region	Name (Syn Gen)	S(MVA)	H (s)	H (MVA.s)	PMU's weight
1	Z1	4058	2.83	11465	25.25
	Z2	749	2.99	2242	4.94
	Z3	880	2.74	2411	5.31
	Z4	957	4.34	4151	9.14
	Z5	817	3.36	2743	6.04
	Z6	936	3.10	2898	6.38
	Z8	1655	2.52	4170	9.19
	Z10	1137	4.46	5076	11.18
	Z11	245	3.84	940	2.07
	Z12	3311	2.81	9303	20.49
		Total H(MVA.s)=		**45399.60192**	

As it mentioned in Table 2, some buses are chosen for monitoring purposes with PMUs. These buses are named z1, z4, z10 and z12 in Table 5. It is worth to mention that selecting these buses for monitoring by PMUs will result in monitoring of 66% of total inertia in region 1. PMU's weights are presented in the form of bar chart for Region 1 in Figure 2-6.

The same procedure is conducted for calculation of PMUs' weights in region 2 and the result is presented in Table 6 and Figure 2-7. It is worth mentioning that in this case, the inertia of two regions are similar. In Practice, the weightings for all regions should consider the difference of regional inertia. Therefore it may be very useful in future tests to have a less even inertia distributed system or an optimized approach to set the PMU weightings.

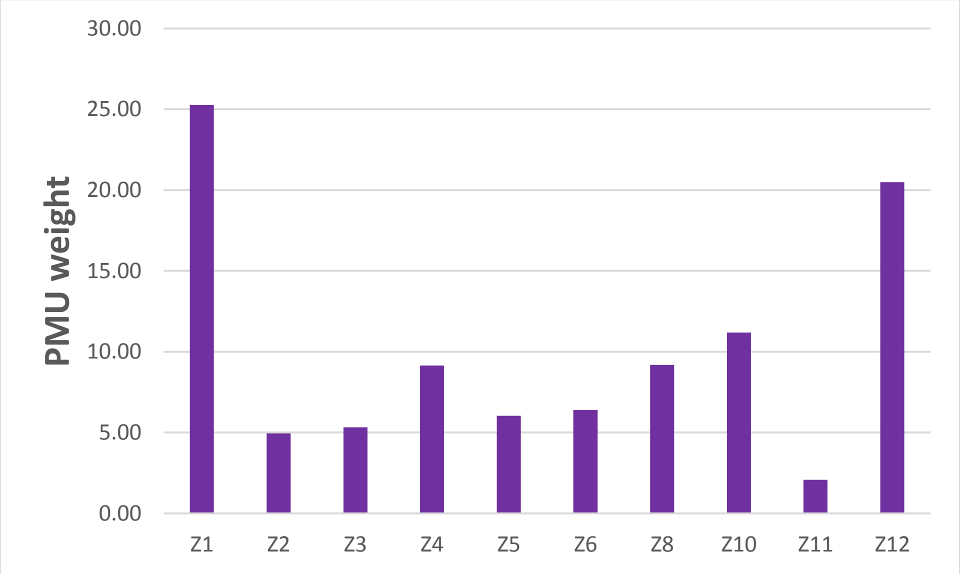

Figure 2-6: PMUs' weights for Region 1

Table 6: PMUs' weights calculation for region 2 in GB system model

Region	Name (Syn Gen)	S(MVA)	H (s)	H (MVA.s)	PMU's weight
2	CCGT	1000	2.50	2500	6.55
	Z15	1034	2.94	3037	7.95
	Z16	450	5.23	2351	6.16
	Z17	273	5.06	1381	3.62
	Z19	582	2.90	1686	4.42
	Z20	908	3.53	3201	8.38
	Z21	498	3.08	1537	4.03
	Z22	1097	2.73	2996	7.85
	Z23	1060	2.92	3097	8.11
	Z24	567	4.69	2660	6.97
	ZScot25	6136	2.24	13730	35.97
		Total H(MVA.s)=		**38176**	

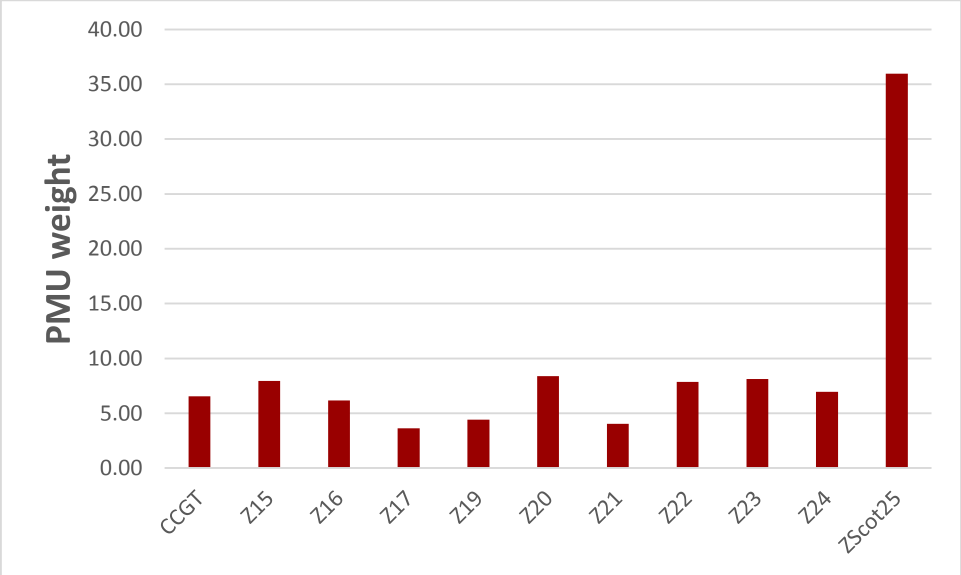

Figure 2-7: PMUs' weights for Region 2

3 Test Description and Cases

Real-time simulations provide a suitable test bed to perform HiL testing, in which the transient processes in a real power system have been simulated using the Manchester RTDS. The Manchester RTDS generates test signals to test the actual GE hardware. The RTDS testing facility provides sufficient flexibility to perform a number of different test scenarios, also considering involvement of all mentioned *service providers in 2.2*.

The test scenario delivered is based on a framework where RTDS uses virtual PMUs to provide IEEE C37.118 streams to the EFCC hardware and receives a suitable (control) output from the EFCC hardware as an input back into the real-time simulation. This “closes the loop” between the simulation and the hardware and allows the real-time simulation to incorporate the response of the control hardware.

The power system test networks that is simulated using the RTDS is a GB network test system which is designed to be representative of the GB system. There is further reduction in the GB model in the number of zone (compared to the 36 zone). The process of this reduction and its validation against the DIgSILENT RMS 36 zone modelled is defined in [5]. This smaller model then allows the incorporation of more complex resource models within an RTDS model sized to the University of Manchester’ RTDS capabilities. The facilities are one of the very best in the UK, but each such test system has its limitations when it comes to the complexity of the test system. Each zone will have a different generation mix and certain significant resources (e.g. large offshore wind farms or new nuclear plants) will appear as distinct entities connected to sub networks within the zone- requiring allocation within a finite RTDS computational capability.

The bulk of the studies will use the above reduced test system, the test system is selected considering the needs of the test and the fact that the hardware available places limitations on the size of the test system and the complexity of the equipment models that can be included in the test system.

This phase of the testing is focusing on entire MCS for a GB network Test System and made up of the following stages and individual tests:

Case study 1: Load increment and disconnection in region 1 & region 2

Test 1.1: MCS Response for a 1000 MW load increment event in in region 1 with sufficient resource

Test 1.2: MCS Response for a 1000 MW load increment event in region 1 with finite resource

Test 1.3: MCS Response for a 1000 MW load increment event in region 2 with finite resource

Test 1.4: MCS Response for a 1500 MW load increment event in region 1 with sufficient resource

Test 1.5: MCS Response for a 1000 MW load disconnection event in region 1 with finite Resource

Case study 2: Security against Short Circuits

Test 2.1: MCS Response for a 140ms single phase ground fault in region 1

Test 2.2: MCS Response for a 140ms single phase ground fault in region 2

Test 2.3: MCS Response for a 140ms double phase ground fault in region 1

Test 2.4: MCS Response for a 140ms three phase ground fault in region 1

Test 2.5: MCS Response for a 140ms three phase ground fault in region 2

Case study 3: Frequency events followed by a short circuit fault

Test 3.1: MCS Response for a load increasement after 140ms short circuit fault in region 1

Test 3.2: MCS Response for a load increasement after 140ms short circuit fault in region 2

Test 3.3: MCS Response for a generator tripping after 140ms short circuit fault in region 1

Test 3.4: MCS Response for a line disconnection after 140ms short circuit fault in region 1

Case study 4: Sensitivity analysis

Test 4.1: Impact of PMU weights on system frequency by comparing *fcoi* from RTDS

Test 4.2: Impact of fault off hysteresis time on event detection after a short circuit fault

Test 4.3: Impact of amount of service provider response

Test 4.4: Impact of ramp up rate of service provider response

3.1 Case study 1: Load increment and disconnection in region 1 & region 2

The purpose of this test is to assess the event detection capability and resource allocation of the EFCC scheme. As such, these tests focus upon load change in the system without considering short circuit fault.

This test will be made up of five sub-tests that are described in detail in this section and are intended to verify the core functionality of the MCS in a complex system, these are:

Table 7: Test cases and aim of case study 1

Test case	Test aim
Test 1.1: MCS Response for a 1000 MW load increment event in in region 1 with sufficient resource	Verify appropriate response delivered to one under-frequency even
Test 1.2: MCS Response for a 1000 MW load increment event in region 1 with finite resource	How is EFCC responding to a disturbance with insufficient volume
Test 1.3: MCS Response for a 1000 MW load increment event in region 2 with finite resource	Verify the ability to detect the event at disturbed region
Test 1.4: MCS Response for a 1500 MW load increment event in region 1 with sufficient resource	Verify the ability of EFCC to counter different event
Test 1.5: MCS Response for a 1000 MW load disconnection event in region 1 with finite Resource	Verify appropriate response delivered to one over-frequency even

Each sub-test investigates one scenario that may impact the performance of the EFCC scheme. These results should serve as a reference point for the more complex tests to follow, which will aid in determining the source of any undesirable behaviour observed in these further tests. Test 1.1 is to first verify the appropriate response to one frequency event is delivered. Then Test 1.2 is used to see respond to the disturbance in the system when faced with an insufficient volume. Test 1.3 then further verified the ability to detect the event at disturbed region. Test 1.4 gives an example of the response of MCS when the size of the event is varied. Finally, an over frequency case with same size and location as Test 1.1 is tested in Test 1.5.

Given the limitations of the RTDS set up, it is not quite feasible to have additional synchronous generators which can be tripped in the test to create a low frequency condition. Instead, a certain MW load increase which is similar to a same amount of bi-pole disconnection is considered as appropriate scenarios. Furthermore, unless otherwise stated, the disturbances are step changes in the active power that are simulated by changing the active power consumption of a load.

The tests inputs that are defined for each test and the test outputs used to evaluate the performance of the scheme for each test are:

Test Inputs: Disturbance size, Disturbance Location, availability of service providers

Test Outputs: The aggregated system frequency and rate of change of frequency, event detection flag, MCS response.

Target Outcome

Verify the behaviour of the LCs, including:

- Instruction to deliver the appropriate MW response
- Angle based targeting – locating the disturbed region
- LC response follows the hierarchy – that is the order in which individual resources will be deployed.

- How the LCs ramp down the resource
- Verify that the LCs is able respond to the disturbance in the system when faced with an insufficient volume

3.2 Case study 2: Security against Short Circuits

The purpose of this test is to assess if the scheme is secure against short circuits. To maximumly explore the robustness of the system, the fault is decided to be located at the bus terminal and configured to have a maximum 140 ms clearing time- the maximum allowing fault clearing time.

Testing Approach

This test will consider following different disturbance sub-tests:

Table 8: Test cases and aim of case study 2

Test case	Test aim
Test 2.1: MCS Response for a 140ms single phase ground fault in region 1	Verify MCS can detect the single phase ground fault
Test 2.2: MCS Response for a 140ms single phase ground fault in region 2	Verify MCS can detect the single phase ground fault at different location
Test 2.3: MCS Response for a 140ms double phase ground fault in region 1	Verify MCS can detect the double phase ground fault
Test 2.4: MCS Response for a 140ms three phase ground fault in region 1	Verify MCS can detect the three phase ground fault
Test 2.5: MCS Response for a 140ms three phase ground fault in region 2	Verify MCS can detect the three phase ground fault at different location

A maximum 140 ms clearing time of the fault will be used for these tests, based on information from National Grid.

The event detection flag will be used to determine if the scheme is secure against these events in cases.

The tests inputs that are defined for each test and the test outputs used to evaluate the performance of the scheme for each test are:

Test Inputs: Fault location, Fault type, Fault duration

Test Outputs: The aggregated system frequency and rate of change of frequency, event detection flag, fault detection flag, MCS response.

Target Outcome

Verify that the scheme is secure against short circuits of a practical duration.

3.3 Case study 3: Frequency events followed by a short circuit fault

The purpose of this test is to assess that how does the MCS respond to an event that occurs during the aftermath of a fault?

Testing Approach

The test here consists of simulating a fault that causes a loss of generation and load increasement. The generator is modelled as a static generator with fixed output. In addition, line disconnection after fault is also considered in this study case. This test will consider following different disturbance sub-tests:

Table 9: Test cases and aim of case study 3

Test case	Test aim
Test 3.1: MCS Response for a load increasement after 140ms short circuit fault in region 1	Verify MCS can detect the fault and response to the frequency event after the fault
Test 3.2: MCS Response for a load increasement after 140ms short circuit fault in region 2	Verify MCS can detect the fault and response to the frequency event after the fault at different region
Test 3.3: MCS Response for a generator tripping after 140ms short circuit fault in region 1	Verify MCS can detect the fault and response to the generator tripping event after the fault
Test 3.4: MCS Response for a line disconnection after 140ms short circuit fault in region 1	Verify MCS can detect the fault and not influenced by line tripping after the fault

The tests inputs that are defined for each test and the test outputs used to evaluate the performance of the scheme for each test are:

Test Inputs: Fault location, Fault type, Fault duration, Event location

Test Outputs: The aggregated system frequency and rate of change of frequency, event detection flag, fault detection flag, MCS response.

Target Outcome

- Verify that the scheme is able to accurately detect and respond to events that occur in the aftermath and faults.
- Verify that the scheme is secure against line disconnection after a fault.

3.4 Case study 4: Sensitivity analysis

In addition to all above mentioned study cases, to further assess the robust and impact of selected key parameter of the MCS, sensitivity analysis is conducted and the results are presented in this report.

Testing Approach

The test here consists of four sub-tests which explore different factors of MCS, i.e. PMU weightings, minimum fault blocking time, service provider availability and ramping up rates. All tests are given below:

Table 10: Test cases and aim of case study 4

Test case	Test aim
Test 4.1: Impact of PMU weights on system frequency by comparing *fcoi* from RTDS	Investigate the impact of weighting of PMUs to the performance of EFCC
Test 4.2: Impact of minimum fault blocking time on event detection after a short circuit fault	Investigate the impact of minimum fault blocking time to the performance of EFCC
Test 4.3: Impact of amount of service provider response	Investigate the impact of amount of service provider response to the performance of EFCC
Test 4.4: Impact of ramp up rate of service provider response	Investigate the impact of ramp up rate of service provider response to the performance of EFCC

The tests inputs that are defined for each test and the test outputs used to evaluate the performance of the scheme for each test are:

Test Inputs: PMU weightings, minimum fault blocking time, service provider availability and ramping up rates

Test Outputs: The aggregated system frequency and rate of change of frequency, event detection flag, fault detection flag, MCS response.

Target Outcome

- Assess the impacts of PMU weightings, minimum fault blocking time, service provider availability and ramping up rates to the MCS.
- Find optimal and suggestive range of tested parameter.

4 Results & Testing Outcomes

4.1 Case study 1: load increment in region 1 & region 2 to study the under-frequency event

4.1.1 Sudden connection of 1000 MW load

Location: Bus 9 in Zone 1:

Table 11 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	200
	PV	1300
Zone 2	CCGT	200
	Wind	300

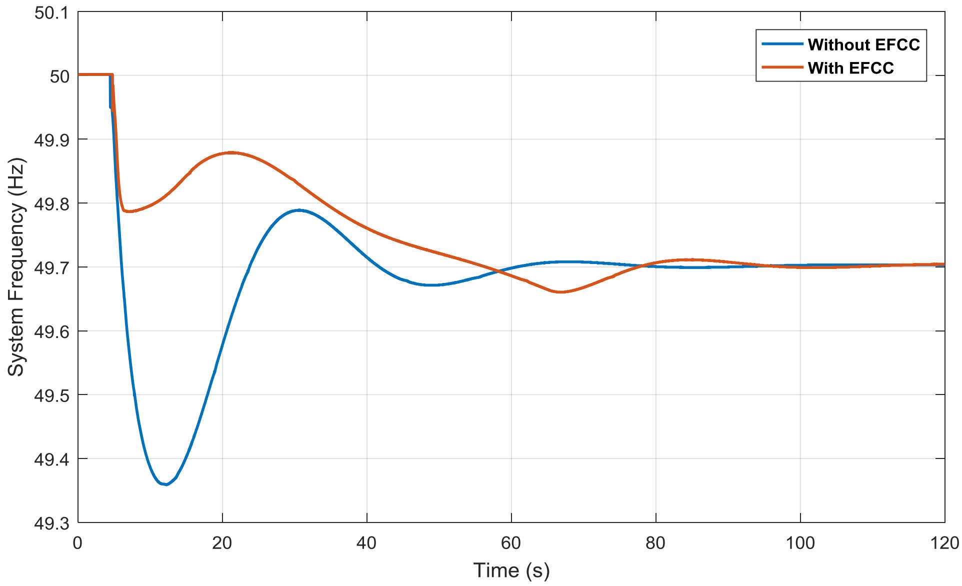

Figure 4-1 System frequency of 1000 MW load increase event at bus 9 zone 1

In this case, the availability of service provider PV, as shown in Table **11** is set to 1300 MW to be sufficient for the disturbance size which is 1000 MW. In Figure **4-1**, the system frequency is obtained from local controller using Phasor Point software. Two cases are compared when the EFCC scheme is activated and not. The effect of EFCC is significant as the frequency nadir is improved from 49.35 Hz which has violated 49.5 Hz limit to 49.65 Hz.

In Figure **4-2**, system RoCoF, event detection signal and response of service provider is given below. It is noted that the RoCoF estimation is 0.2 Hz/s which is larger than predefined threshold 0.15 Hz/s, showing in appendix a, so that the event is detected, and service provider has responded. In this case, 700 MW is requested from PV.

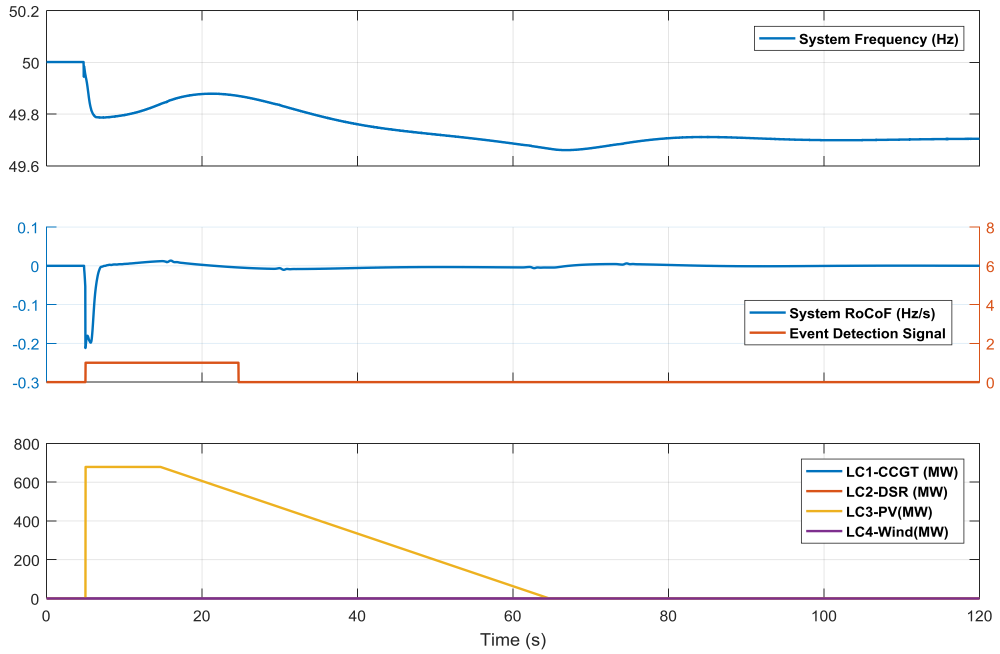

Figure 4-2 Simulation results of 1000 MW load increase at bus 9 zone 1

To further illustrate that how EFCC and MCS has operated, Figure **4-4** is given which shows the details in the first 2 seconds when disturbance happened. It is noted that the event detection and response request time is 250 ms. Additionally, at the beginning of the event (at 1s), there is a spike in the system frequency which caused by the sudden system angle changes due to the sudden power imbalance, which is not reflecting the actual system frequency. The MCS can detect this abnormal spike and not to response initial transient but rather the longer-term frequency trend.

It is also notable that the after the service provider has dispatched its power and start to pull off, a second frequency drop is observed. In Figure **4-3**, a study is conducted to show the effect of the pulling off speed of service provider (50 s and 100 s for pulling off the service provider). If ramping down of EFCC in a slower speed, a better frequency behaviour after 40s can be achieved, as the governors are now slowly responding to slower falling frequency. However, it means that the service providers are required to be able to sustain the output for a longer period.

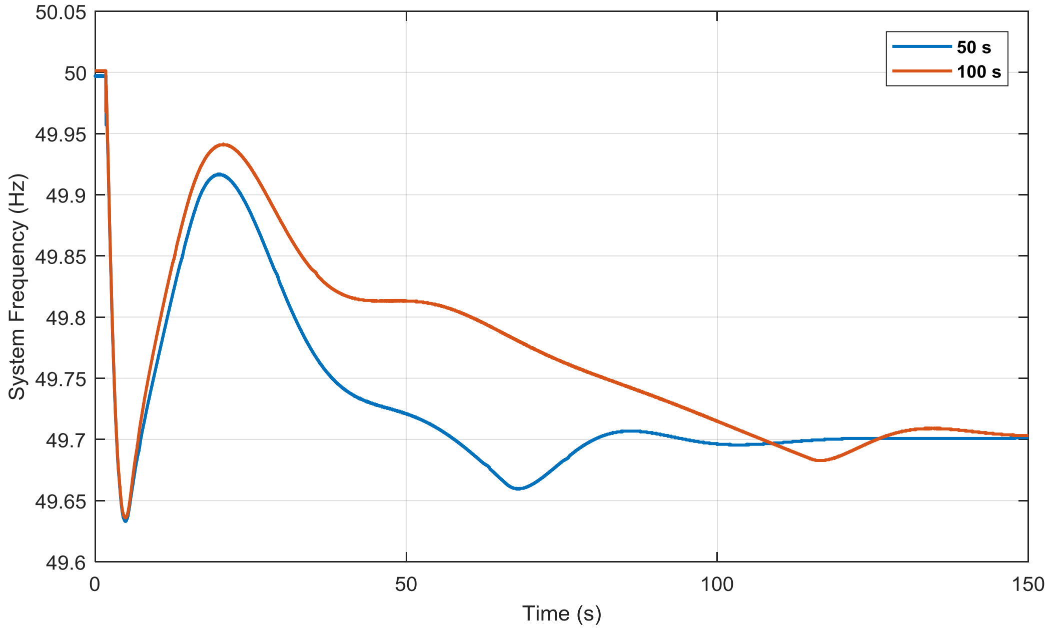

Figure 4-3 Simulation results of 1000 MW load increase at bus 9 zone 1 with two different resource pulling off speed

It should also be pointed out that the post contingency steady state frequency is below 49.8 Hz. In practice, secondary control should kick in and improve the frequency back above 49.8 Hz. However, in the test, no secondary control is considered therefore, the steady state frequency after the event is mainly determined by the droop setting of the generator governor.

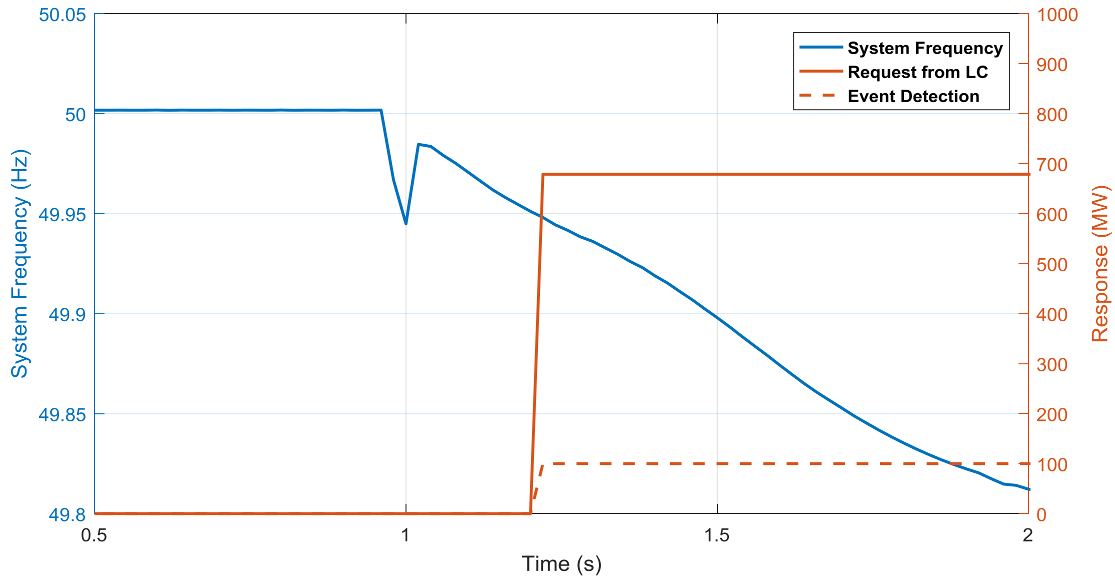

Figure 4-4 Simulation results of 1000 MW load increase at bus 9 zone 1

Location: Bus 9 in Zone 1:

Table 12 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	300

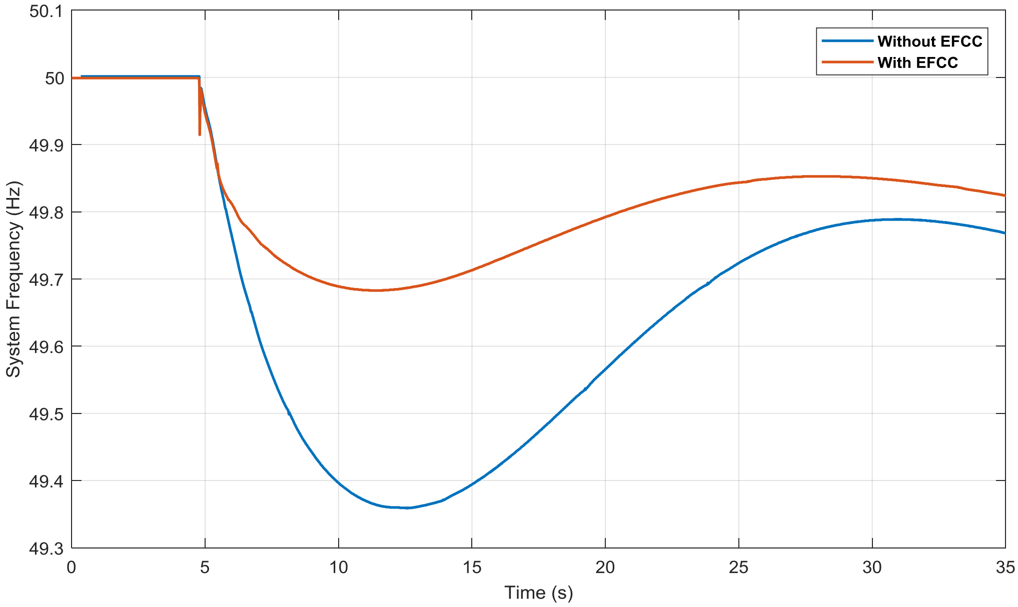

Figure 4-5 System frequency of 1000 MW load increase at bus 9 zone 1 with limited resources

In reality, there is always possibility that the service provider in disturbed zone is not sufficient to fully cover the power imbalance. In this case, only 500 MW is available in zone 1 which is only 50% of the initial power imbalance. Even though it is clearly shown that the frequency nadir is as 49.68 Hz lower than the case with enough resources, the system frequency is still quite over the 49.5Hz limit. In other words, less response is needed to effectively improve the frequency nadir.

It is noted that DSR has participate in this case which will remain on for significant longer period of time so that process the switching down of DSR is not shown in this case.

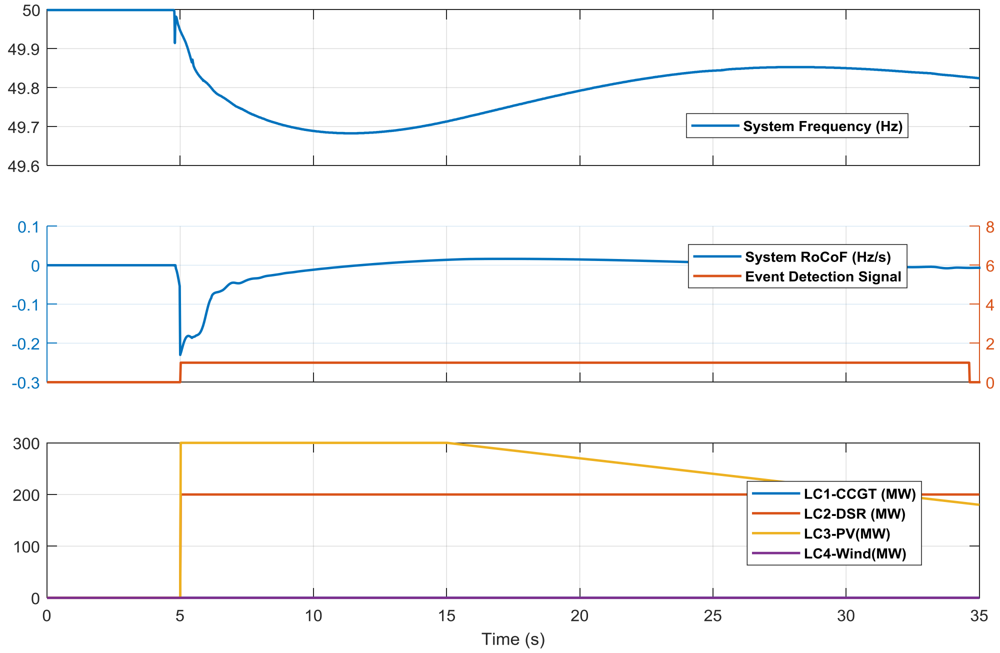

Figure 4-6 Simulation results of 1000 MW load increase at bus 9 zone 1 with limited resources

Location: Bus 21 in Zone 2:

Table 13 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	1300

In this case, the location of the disturbance is moved to the other zone to test if the MCS can correctly detect the location and issue corresponding command.

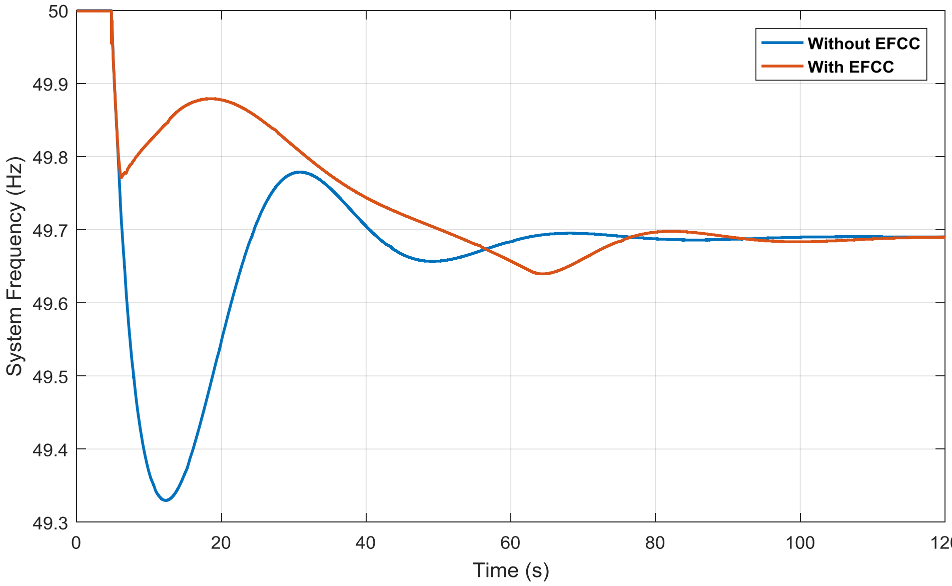

Figure 4-7 System frequency of 1000 MW load increase at bus 21 zone

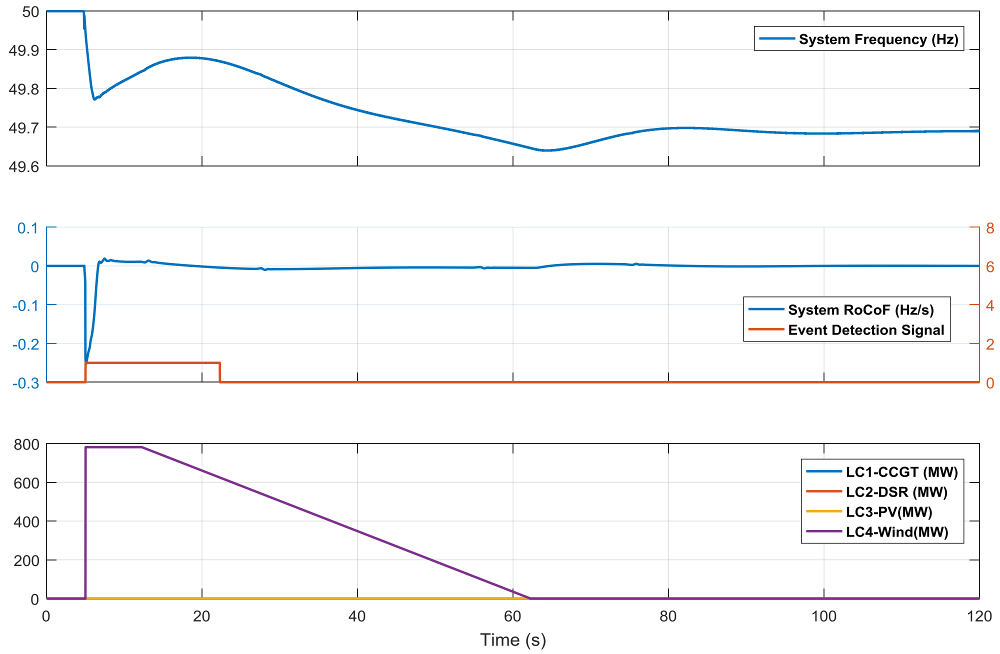

Figure 4-8 Simulation results of 1000 MW load increase with limited resources at bus 21 zone 2

It can be seen from Figure **4-8** that the Wind service provider located in zone 2 has been allocated to response to the disturbance.

4.1.2 Sudden connection of 1500 MW load

Location: Bus 9 at Zone 1:

Table 14 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	200
	PV	1300
Zone 2	CCGT	200
	Wind	300

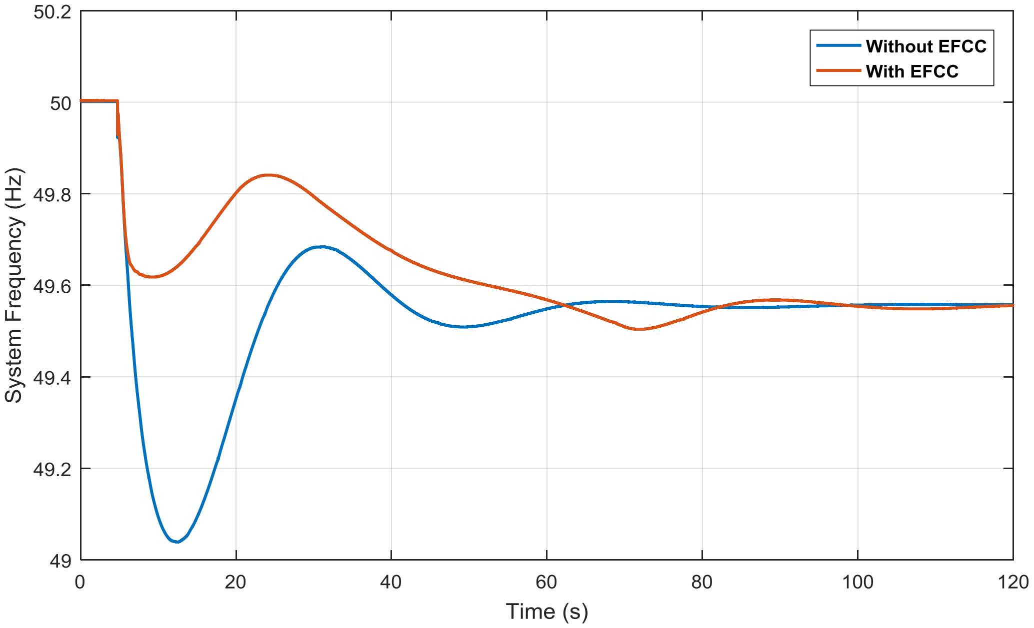

Figure 4-9 System frequency of 1500 MW load increase event at bus 9 zone 1

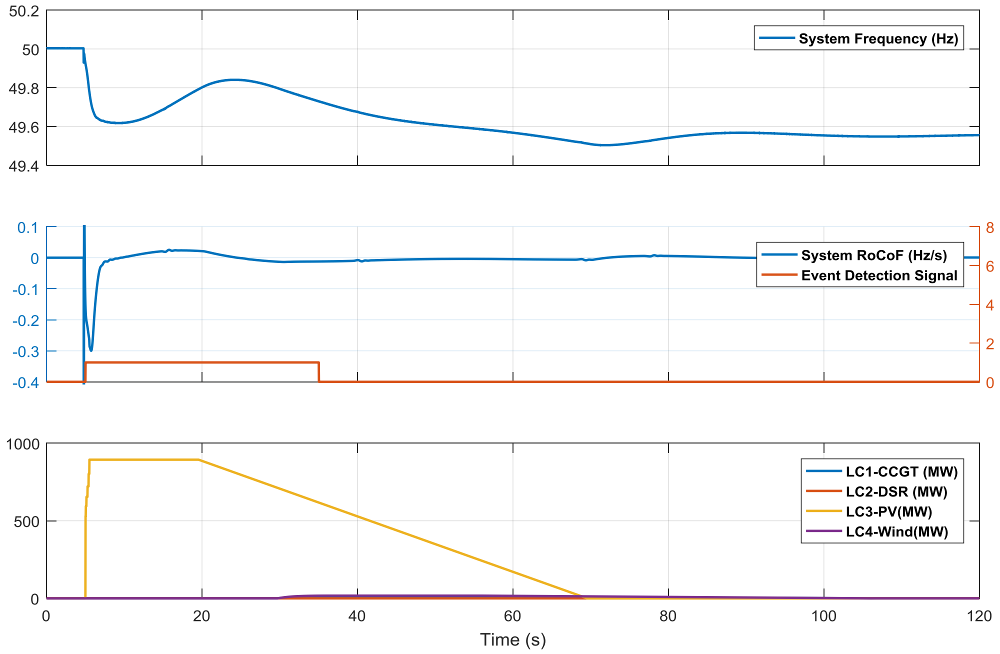

Figure 4-10 Simulation results of 1500 MW load increase at bus 9 zone 1

To further explore the capability of the MCS, the disturbance size is set to 1500 MW which is close to the maximum possible generator loss in GB. The RoCoF measured in Figure **4**-**10** is 0.3 Hz/s. However, the requested response is not significantly larger, due to the spike caused by large disturbance.

Location: Bus 9 at Zone 1:

Table 15 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	300

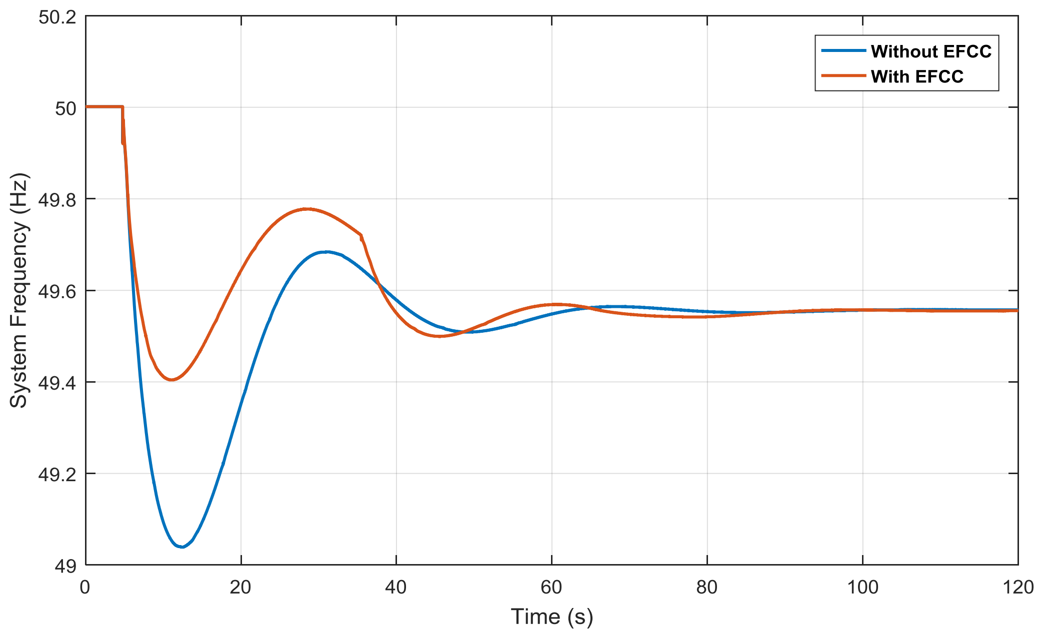

Figure 4-11 System frequency of 1000 MW load increase at bus 9 zone 1 with limited resources

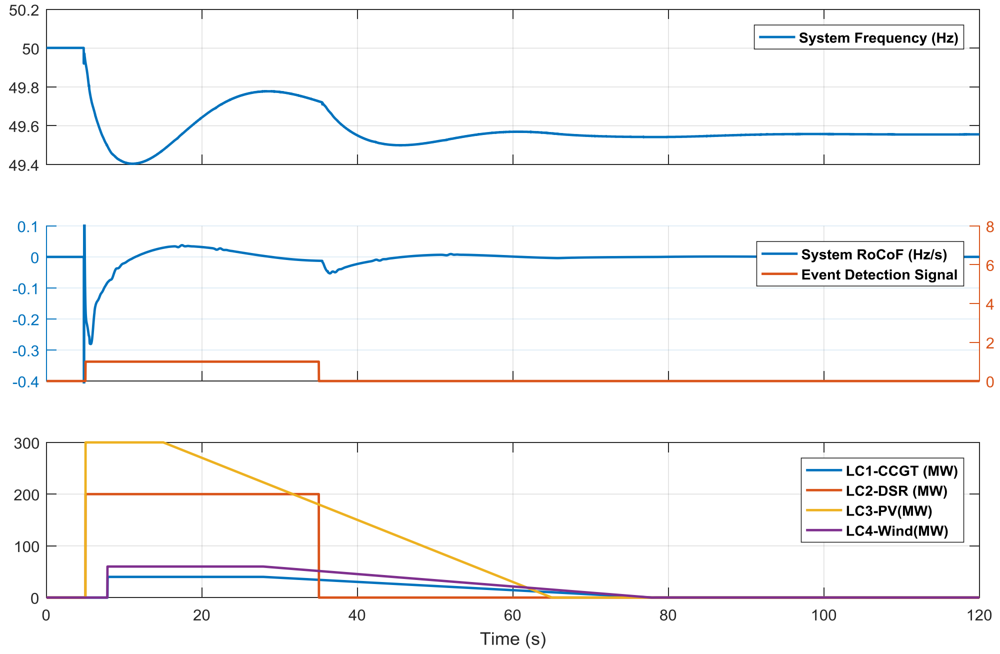

Figure 4-12 Simulation results of 1500 MW load increase at bus 9 zone 1 with limited resources

In this case, the availability of service provider is extremely limited compared to the disturbance size, only 33 percentage of the disturbance. It is noted that all available power in zone 1, PV and DSR, have been requested. In addition, CCGT and Wind are also requested after 2 seconds of event detection due to the mechanism of local-coordinate mode that service providers from other zones contributes to the event and frequency recovery.

4.1.3 Sudden load disconnection of 1000 MW load

Location: Bus 9 at Zone 1:

Table 16 Availability of service providers

	Service provider	Available power (MW)
Zone 1	DSR	0
	PV	500
Zone 2	CCGT	200
	Wind	300

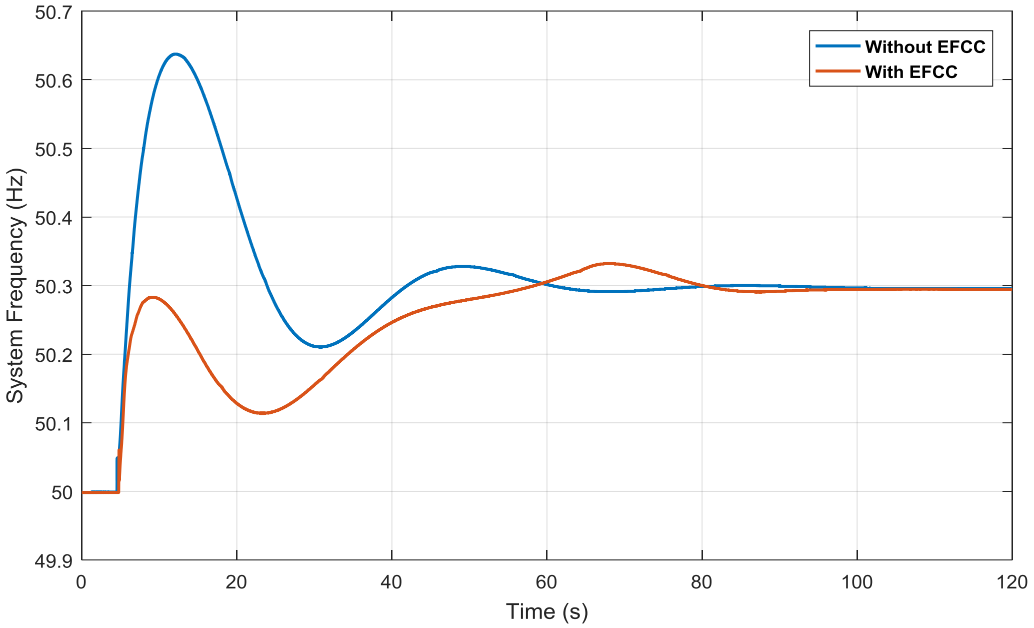

Figure 4-13 System frequency of 1000 MW load increase at bus 9 zone 1 with limited resources

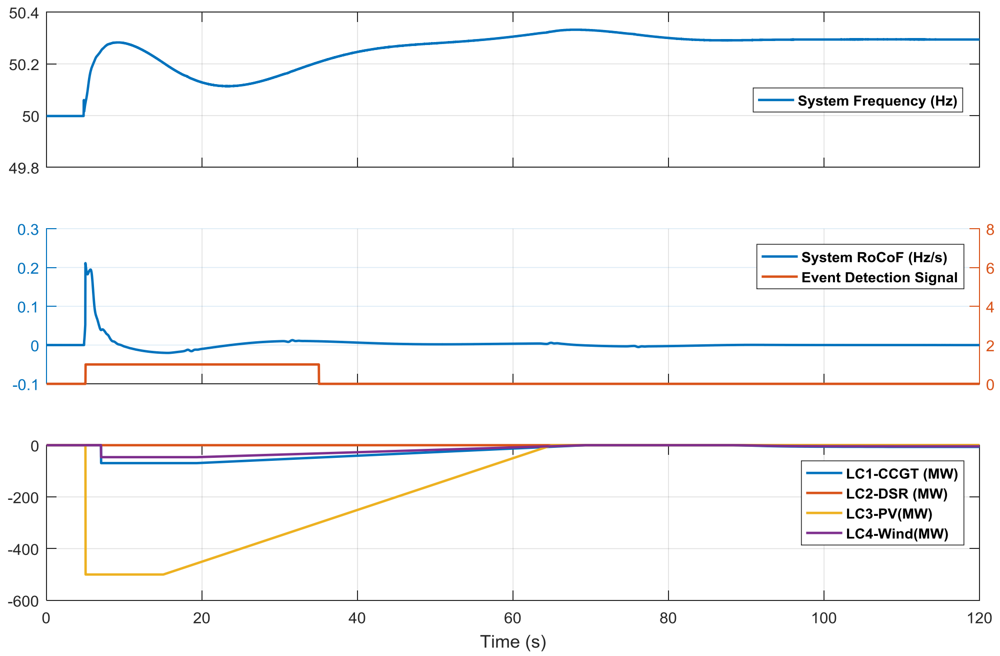

Figure 4-14 Simulation result of 1000 MW load increase at bus 9 zone 1 with limited resources

Instead of load connection, load disconnection is also a typical reason of system frequency event. In this case, a 1000 MW load is disconnected at bus 9 in zone 1. The maximum frequency is reduced from 50.64 Hz to 50.35.

Learning Outcomes:

- The scheme is verified to deliver the appropriate MW response
- The scheme is verified to locate the disturbance in the right region
- LC responses follow the hierarchy – that is the order in which individual resources will be deployed.
- The scheme is able respond to the disturbance in the system when faced with an insufficient volume
- The scheme can effectively contain events that traditional services could not, however in doing so the pullback of the scheme needs to be coordinated with primary response and other frequency responses in the system.

4.2 Case study 3: study the effect of different types of short circuit fault at different buses and zones

Any fault will be detected in regional aggregator. In this case study, different faults are simulated and studied. Fault detected signal is also shown in the following cases.

Fault should not be detected as a frequency event and it should be filtered by event detection AFB algorithm and would not require a response from service providers.

Table 17 gives the availability of all service providers used for the test of fault cases.

Table 17 Availability of service providers

	Service provider	Available power positive (MW)	Available power negative (MW)
Zone 1	DSR	200	0
	PV	300	500
Zone 2	CCGT	200	300
	Wind	300	200

4.2.1 140ms Single line ground fault

Location: Bus 3 at Zone 1:

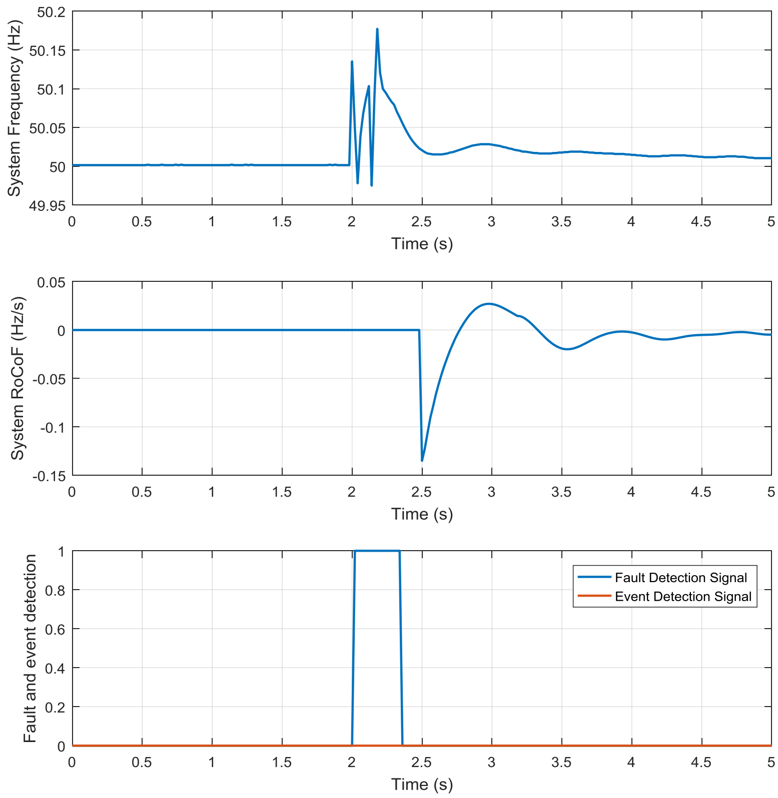

Figure 4-15 Simulation result of 140 ms Single line ground fault at Bus 3 Zone 1

From Figure **4-15**, it can be seen that regional aggregator has been detected a fault in the system and after clearing fault the event detected signal is reset.

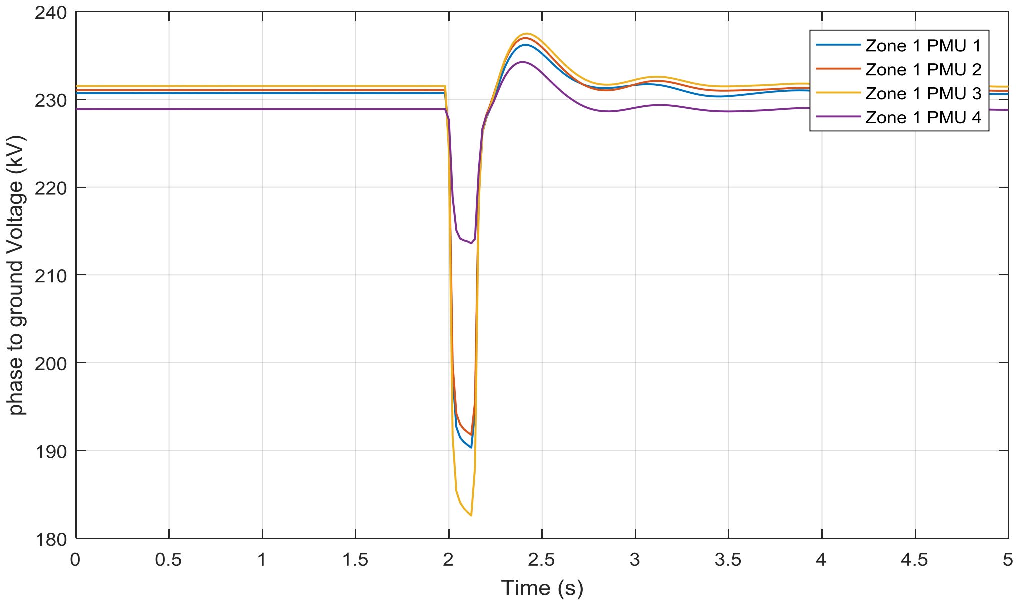

Figure 4-16 Zone 1 PMU voltages of 140 ms Single line ground fault at Bus 3 Zone 1

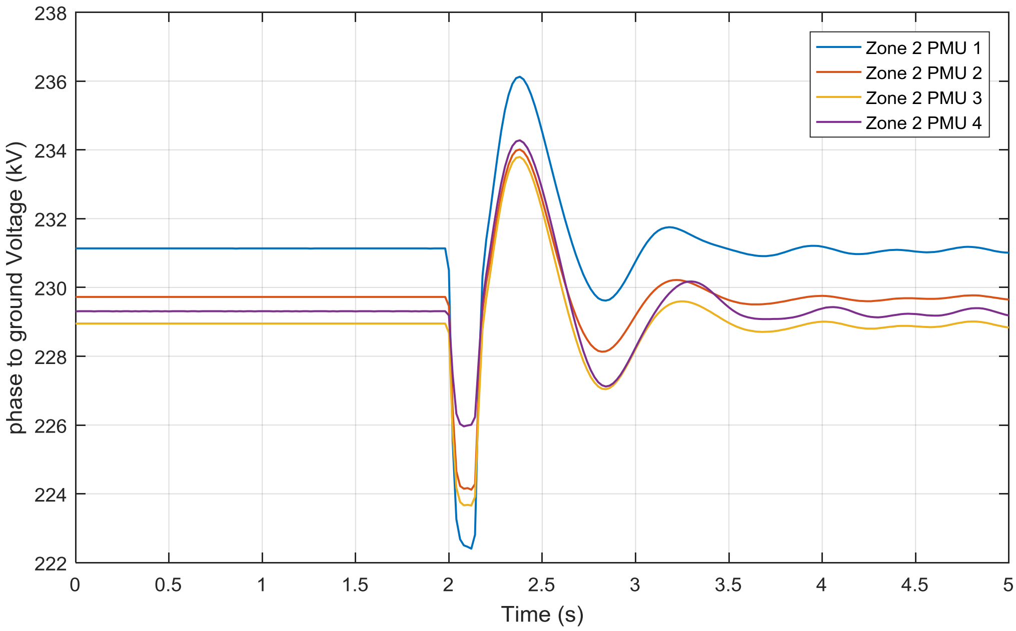

Figure 4-17 Zone 2 PMU voltages of 140 ms Single line ground fault at Bus 3 Zone 1

From Figure **4-16**, it can be seen that the voltage at zone 1 dropped below threshold (0.85 p.u.) which triggered fault detection block. On the other hand, it is also noted that the voltage in the system is largely depressed through the whole system. the closer to the fault location, the deeper voltage drop is observed.

Location: Bus 16 at Zone 2:

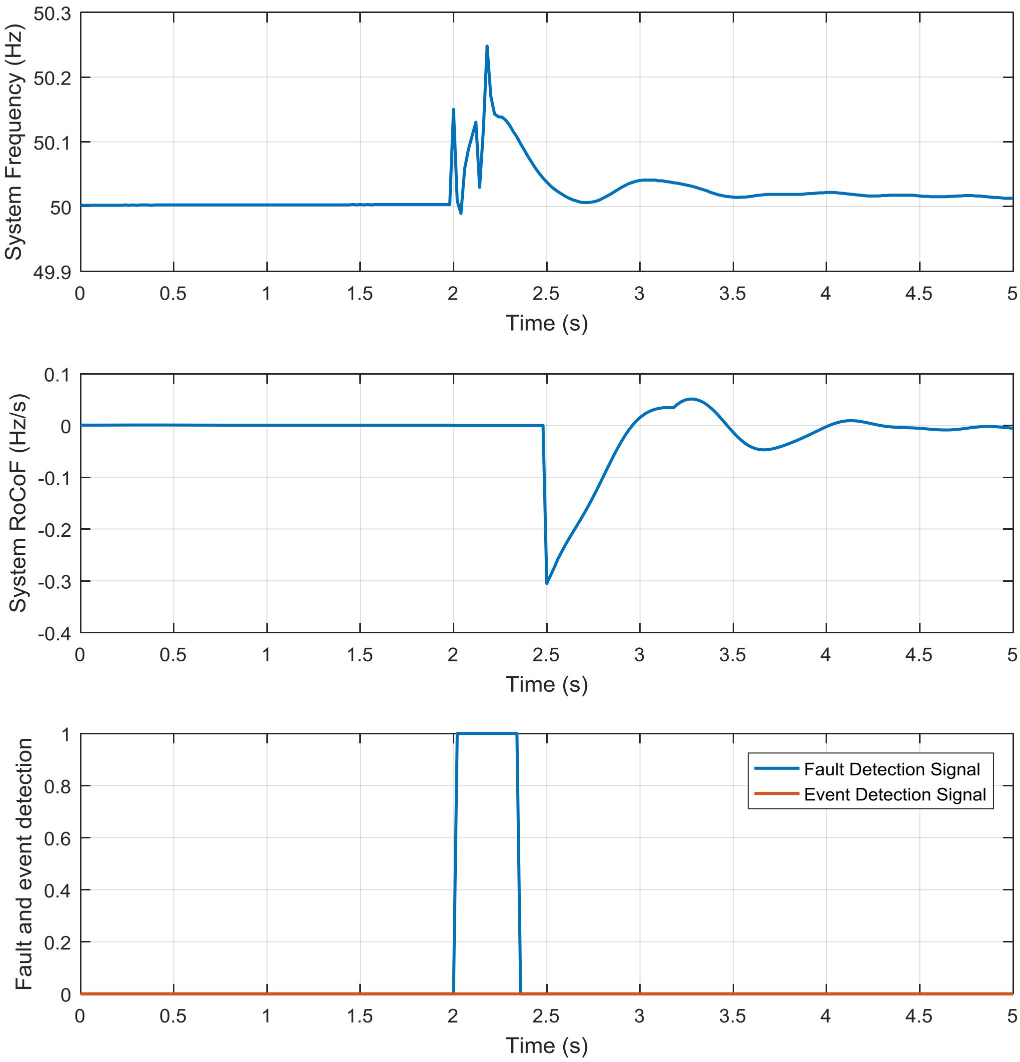

Figure 4-18 Simulation result of 140 ms Single line ground fault at Bus 16 Zone 2

In this case, the fault location is moved to zone 2 at bus 16. The results have shown that the fault detection and blocking works as expected for single phase ground fault.

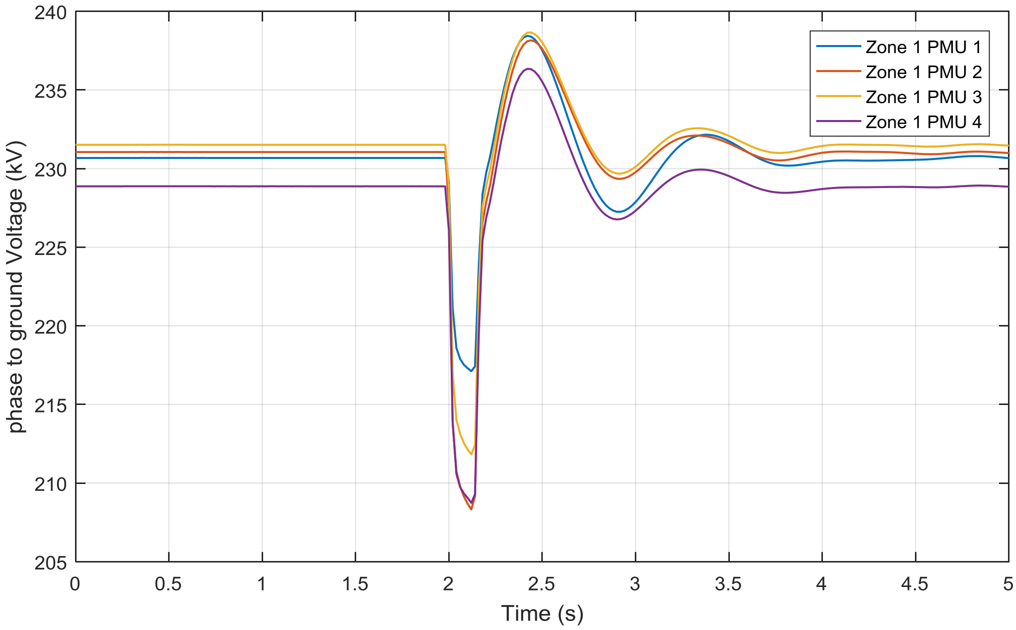

Figure 4-19 Zone 1 PMU voltages of 140 ms Single line ground fault at Bus 16 Zone 2

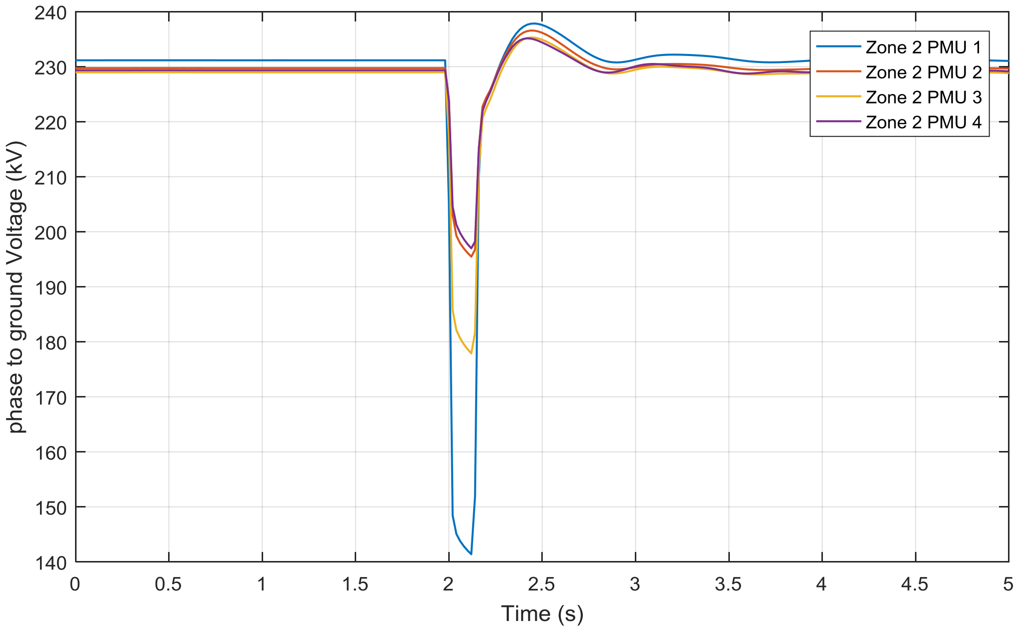

Figure 4-20 Zone 2 PMU voltages of 140 ms Single line ground fault at Bus 16 Zone 1

4.2.2 140ms two phase ground fault

Location: Bus 3 at Zone 1:

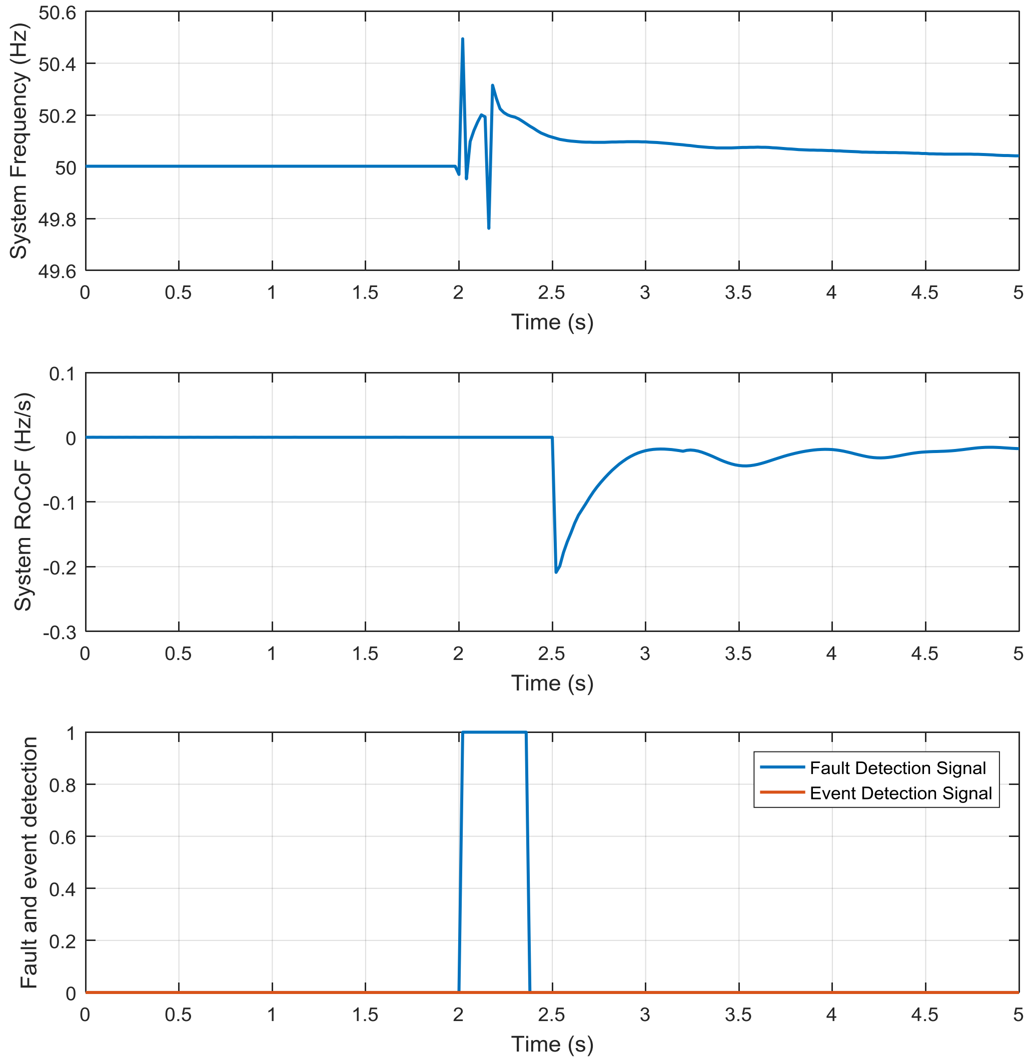

Figure 4-21 Simulation result of 140 ms two phase ground fault at Bus 3 Zone 1

A two-phase ground fault is applied. It can be seen that the frequency jump during fault is larger than previous case due to the nature of fault.

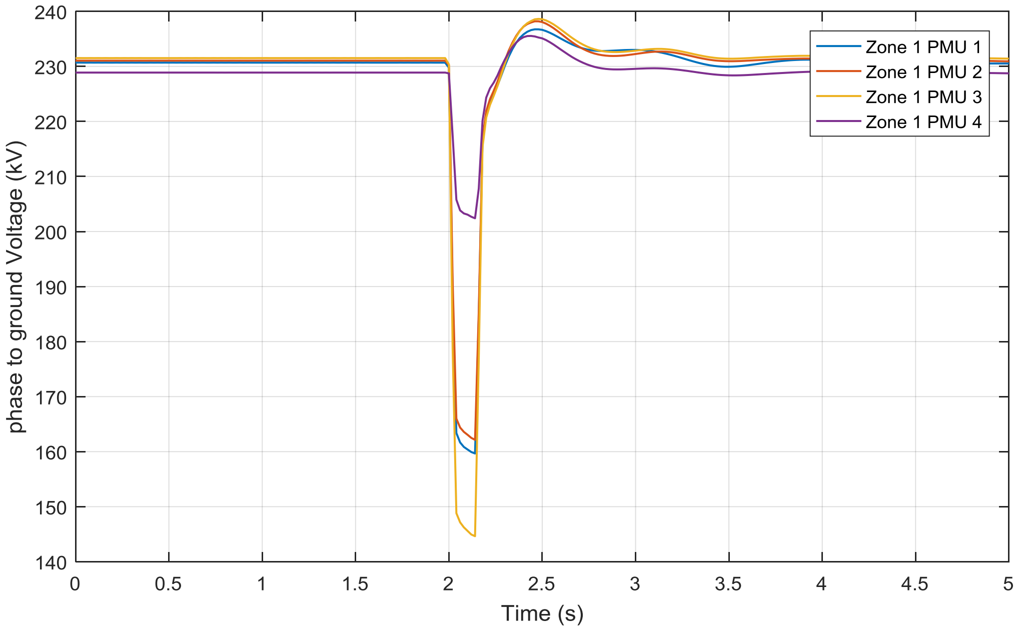

Figure 4-22 Zone 1 PMU voltages of 140 ms two ground fault at Bus 3 Zone 1

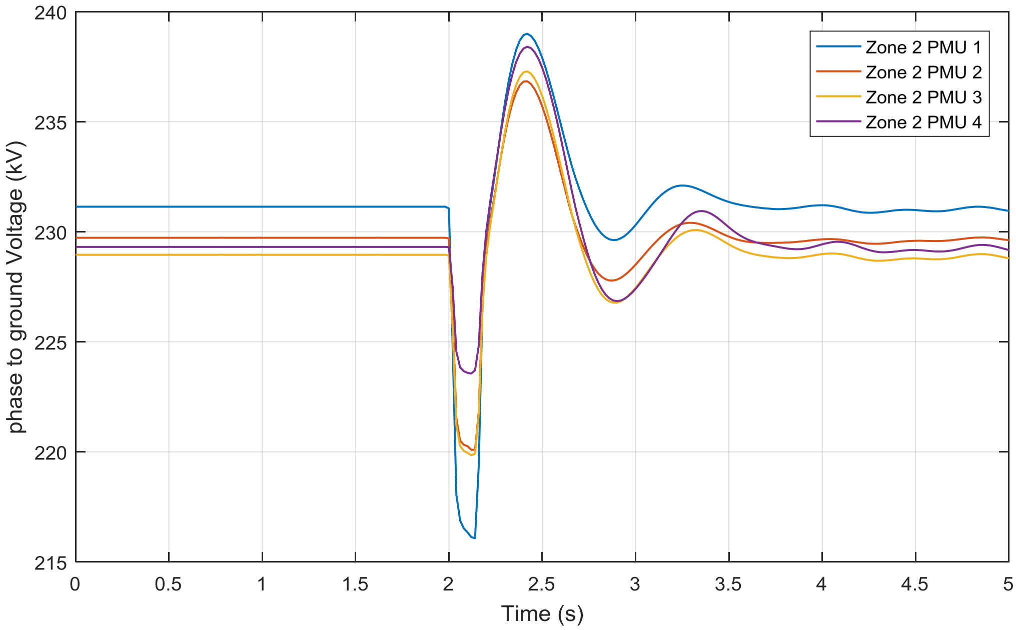

Figure 4-23 Zone 2 PMU voltages of 140 ms two phase ground fault at Bus 3 Zone 1

4.2.3 140ms three phase fault

Location: Bus 3 at Zone 1:

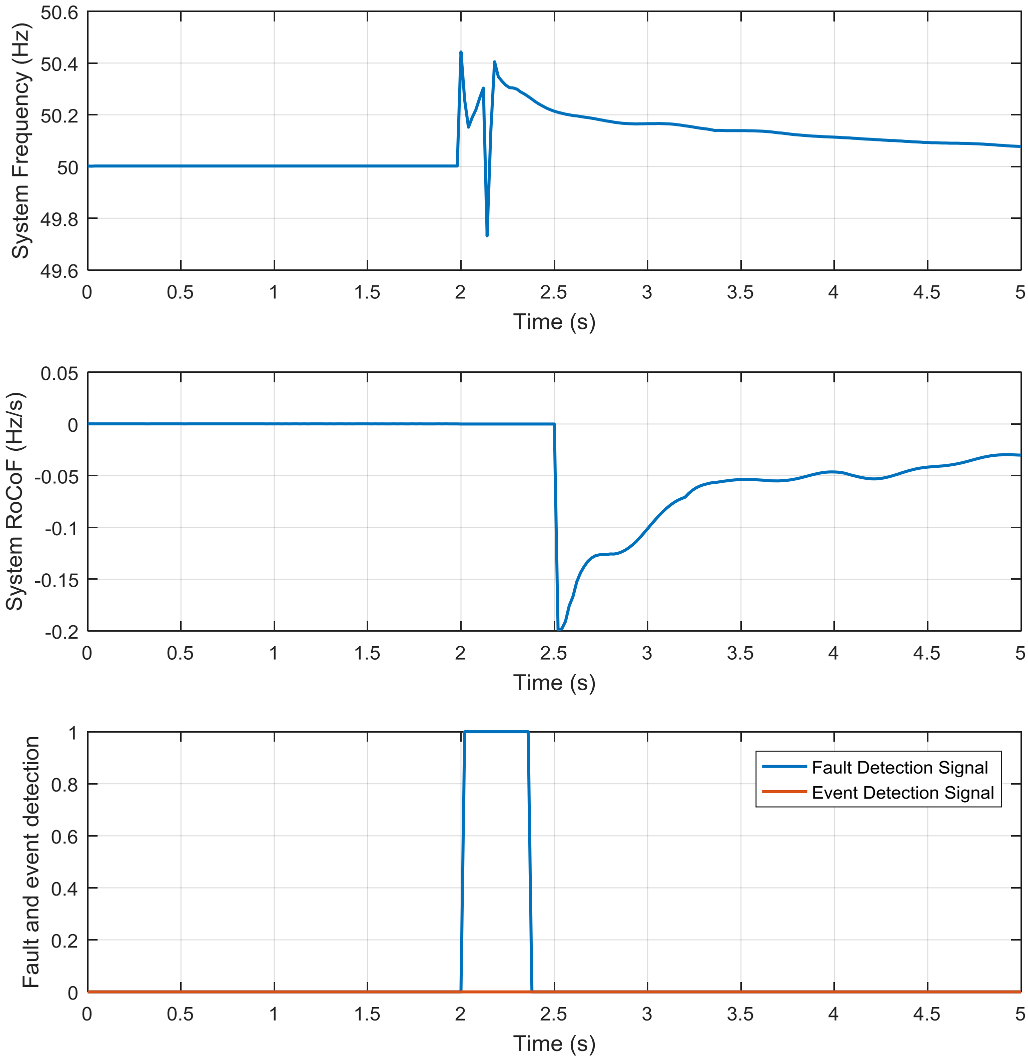

Figure 4-24 Simulation result of 140 ms three phase ground fault at Bus 3 Zone 1

In this case, a 140 ms three phase fault is applied. With a three phase fault, the system is largely impacted, and the system frequency has shown a tremendous increase due to the fault. Therefore, after fault cleared and frequency recovering, the RoCoF is over -0.15 Hz/s for a very short period which doesn’t trigger event detection. However, it proves that a short circuit fault can possibly trigger the event detection after the fault cleared.

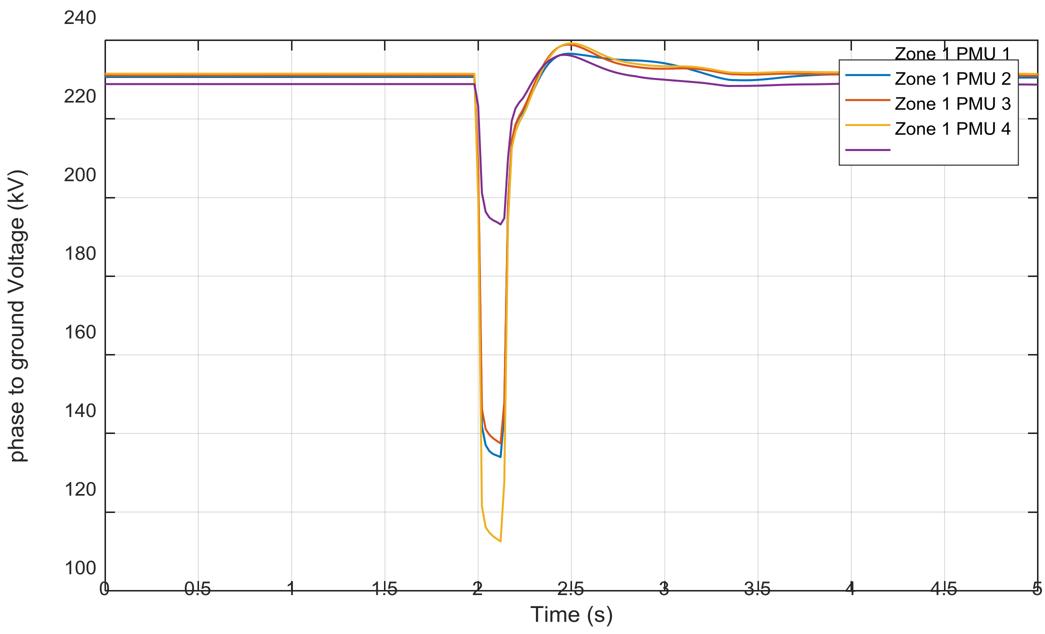

Figure 4-25 Zone 1 PMU voltages of 140 ms three phase ground fault at Bus 3 Zone 1

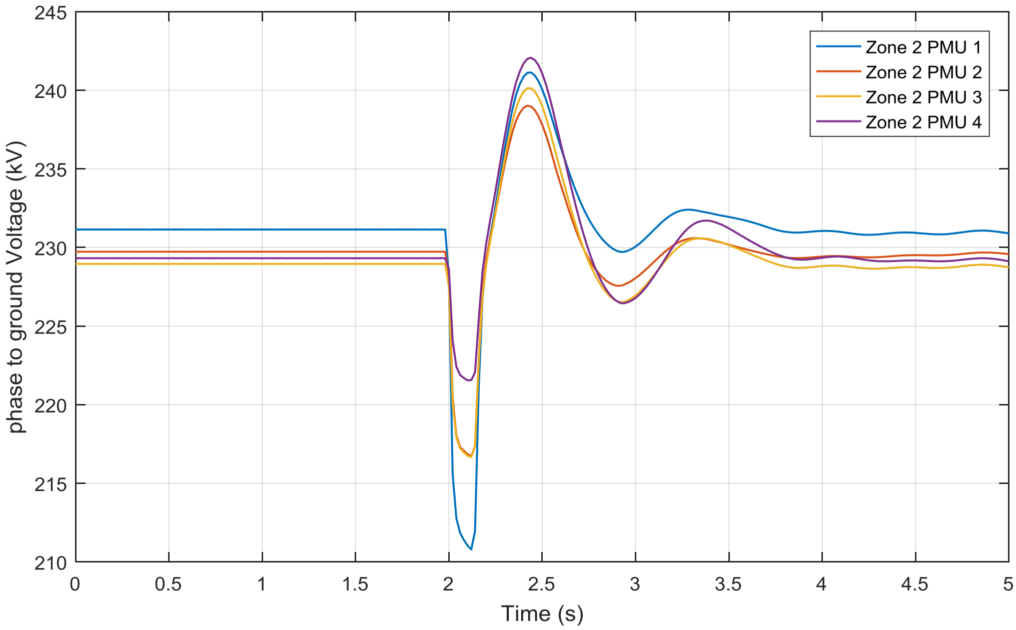

Figure 4-26 Zone 2 PMU voltages of 140 ms three phase ground fault at Bus 3 Zone 1

Location: Bus 16 at Zone 2:

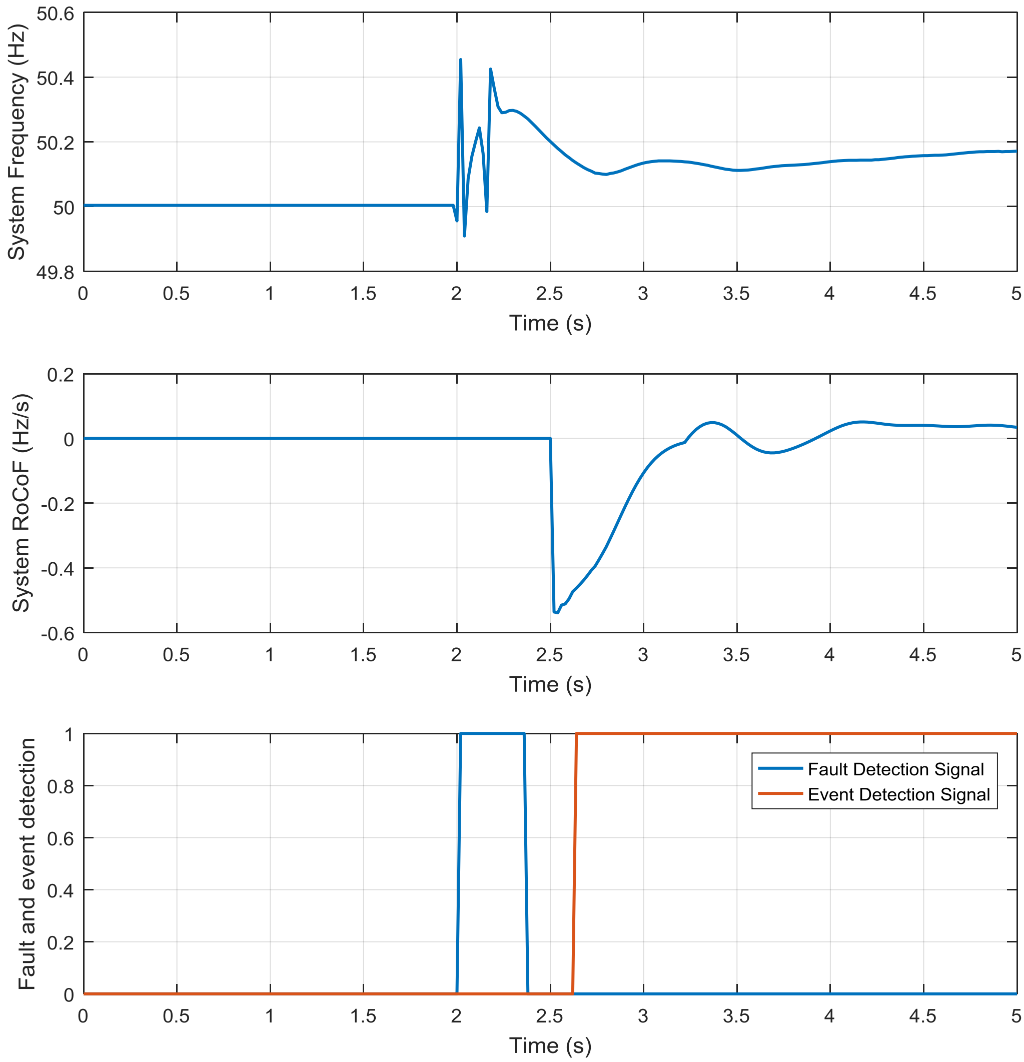

Figure 4-27 Simulation result of 140 ms three phase ground fault at Bus 16 Zone 2

When the fault location changed to bus 16 in zone 2, event detection is triggered when fault cleared. The reason is that the location of fault can have very different impact to the system frequency depends on its electrical distance to the load center. In this case, bus 16 is inside the system and surrounded by many big loads. So during the fault, load will be depressed leading frequency ramping up fast, and when fault clear, load will try to recover to nominal value results a fast frequency dropping down.

The current settings of the MCS would need to be reviewed to avoid it triggering by the weights on the measurement or by changing some of the local fault detection or other appreciate approach. Further review of the settings to tune out such detection would be needed for this event.

It should be noted that in RTDS GB test system, the loads are directly connected at the transmission level which makes it more vulnerable to a fault applied at the same transmission busbar. In reality, many loads will be inside the distribution network which may not be affected so seriously. In order to understand this in principle it would necessary to model the distribution system and introduce PMUs within it where there are EFCC resources connected.

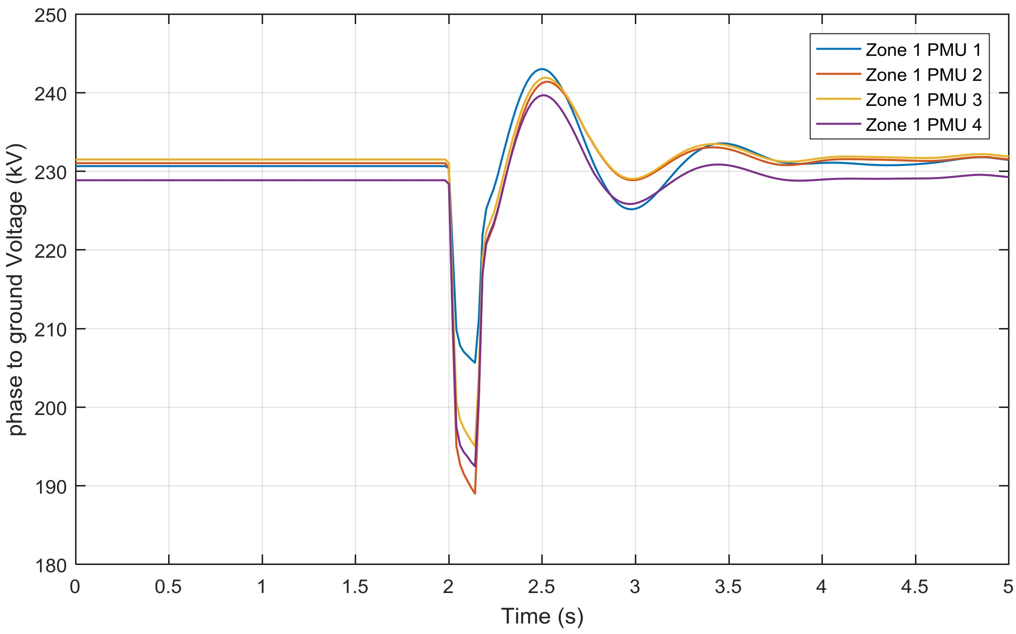

Figure 4-28 Zone 1 PMU voltages of 140 ms three phase ground fault at Bus 16 Zone 2

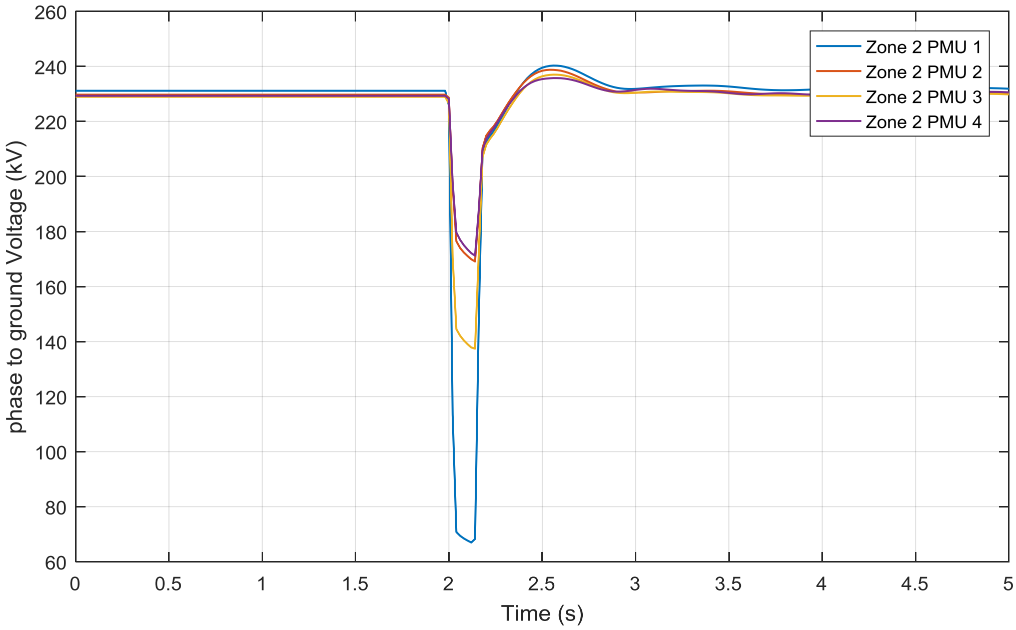

Figure 4-29 Zone 2 PMU voltages of 140 ms three phase ground fault at Bus 16 Zone 2

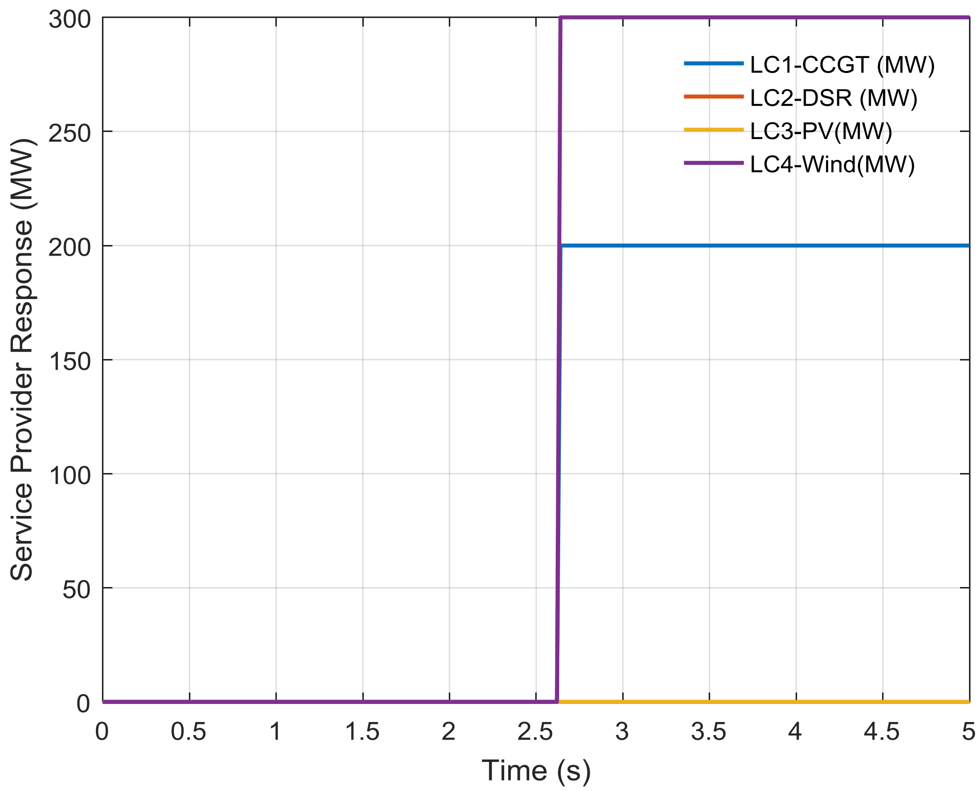

Figure 4-30 Event detection of 140 ms there phase ground fault of 1500 MW load increase at Bus 16 Zone 2

Learning Outcomes:

- The voltages at different buses during fault are widely depressed.
- The scheme is secure against short circuits with consideration of practical duration and different fault type and locations.
- It is observed that a very severe fault which strongly impacted the system can actually lead the scheme to trigger. Some parameter like minimum fault blocking time can be used to resolve this problem. This is analysed in the sensitivity analysis section.

4.3 Case study 4: event after fault

It is also very important to test cascading event as in real network, most disturbance is caused by faults.

4.3.1 1000 MW Load increment at bus 9 after fault at bus 8

Table 18 Availability of service providers

	Service provider	Available power positive (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	300

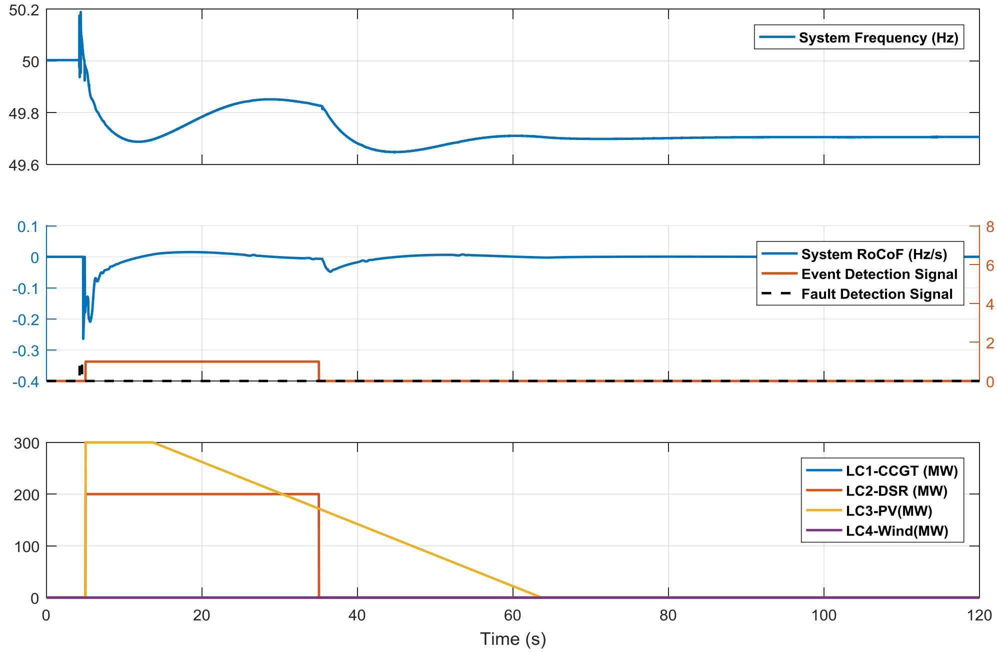

Figure 4-31 Simulation results (Zoomed) of load increase after fault at bus 8

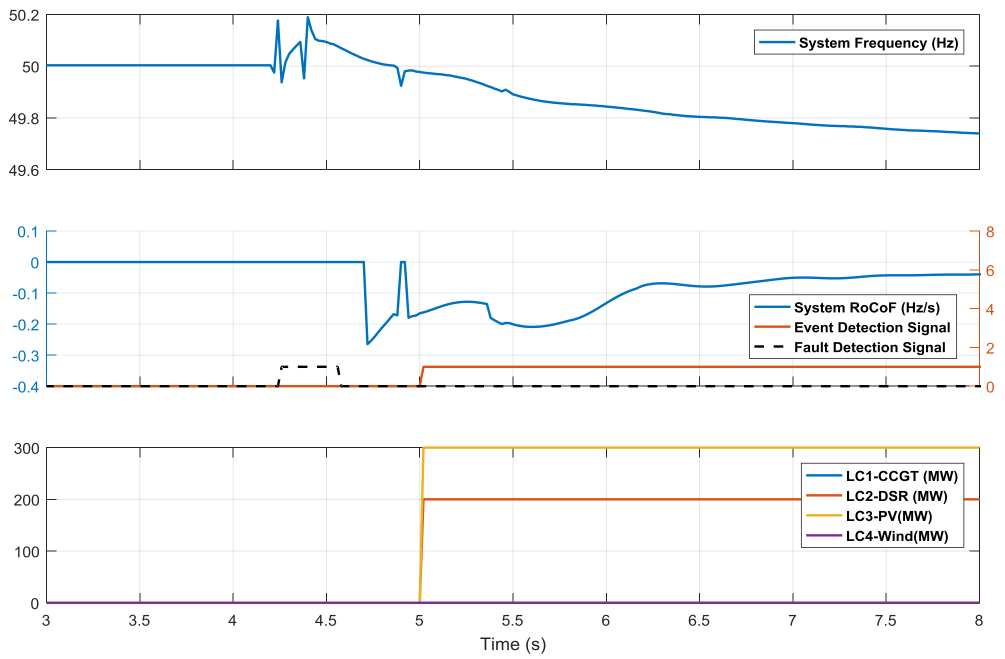

Figure 4-32 Simulation results (Zoomed) of load increase after fault at bus 8

In this case, a 1000 MW load is connected after a 140ms single phase ground fault cleared. It is shown in Figure **4-32** that fault is detected successfully and after a cooling down period, the following frequency event is detected as well. PV and DSR have responded to the disturbance correctly.

4.3.2 1000 MW load increment at bus 24 after fault at bus 22

Table 19 Availability of service providers

	Service provider	Available power positive (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	300

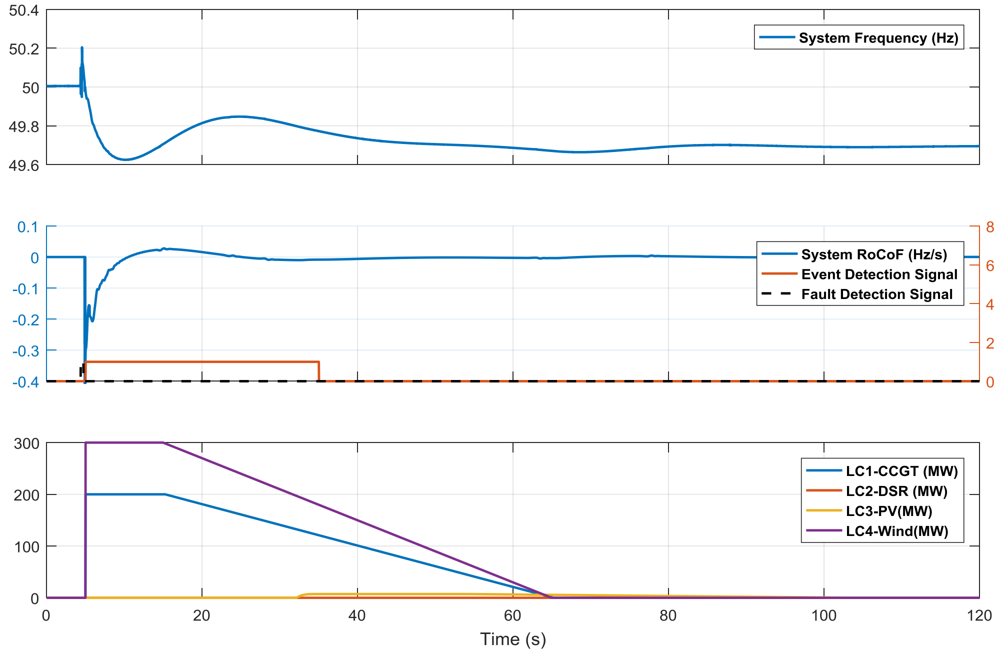

Figure 4-33 Simulation results of load increase after fault at bus 22 in zone 2

In this case, a 1000 MW load is connected at 22 in zone 2 after a 140ms single phase ground fault cleared. It is shown in Figure **4**-**33** that fault is detected successfully and after a cooling down period, the following frequency event is detected as well. Wind and CCGT have responded to the disturbance correctly.

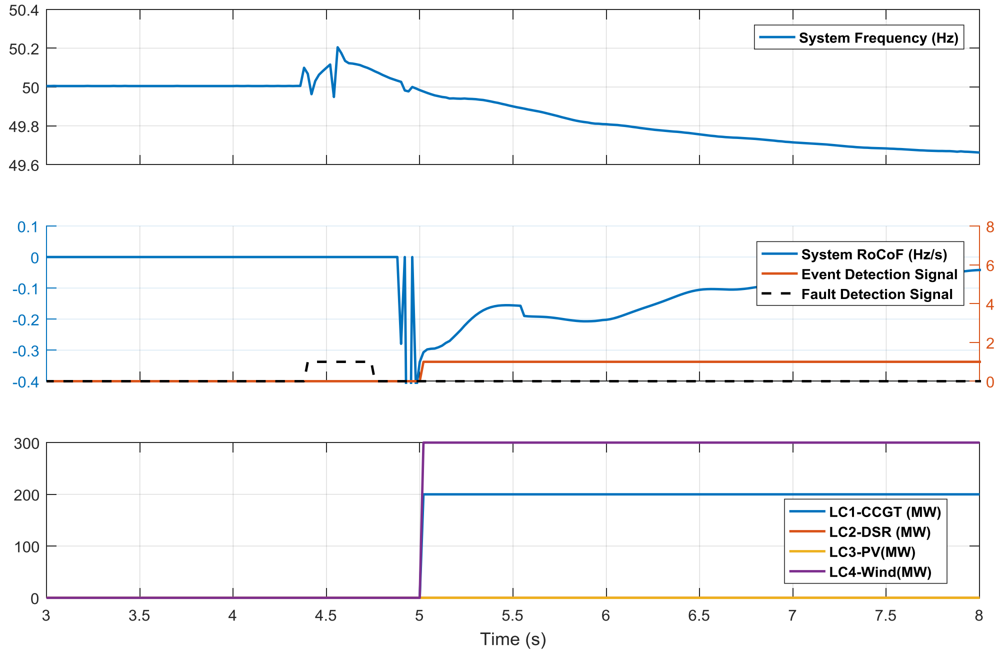

Figure 4-34 Simulation results (Zoomed) of load increase after fault at bus 22

4.3.3 Line tripping (13-17) after fault at bus 13

Table 20 Availability of service providers

	Service provider	Available power positive (MW)
Zone 1	DSR	200
	PV	300
Zone 2	CCGT	200
	Wind	300

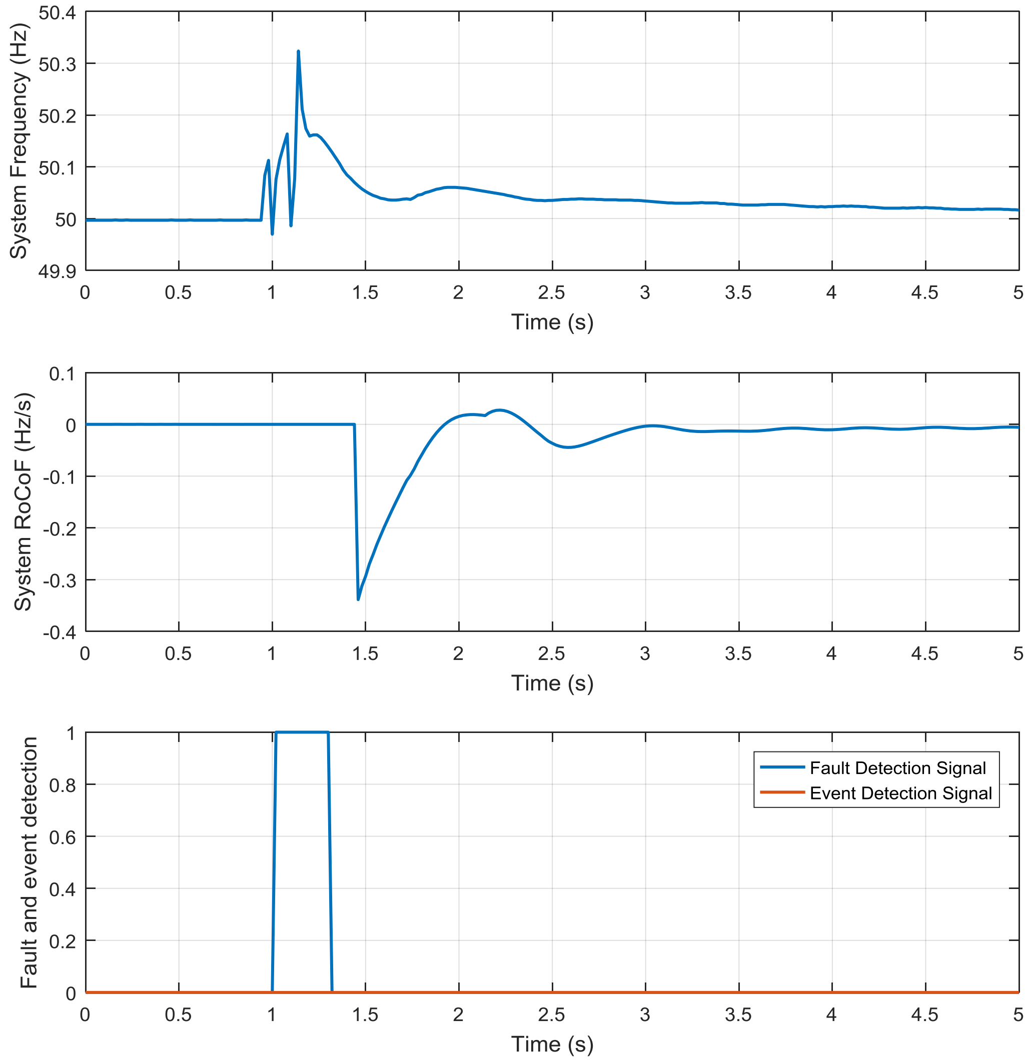

Figure 4-35 Simulation results of line 13-17 tripping after fault at bus 13

In this case, a 140 ms single phase ground fault is applied at bus 13 and then line 13-17 is tripped. As shown in the figure, line tripping does not affect the system seriously. However, the fault is still the first reason for frequency disturbance in this case.

4.3.4 Generator tripping (Asyn at bus 5) after fault at bus 5

Table 21 Availability of service providers

	Service provider	Available power positive (MW)
Zone 1	DSR	200
	PV	1000
Zone 2	CCGT	200
	Wind	300

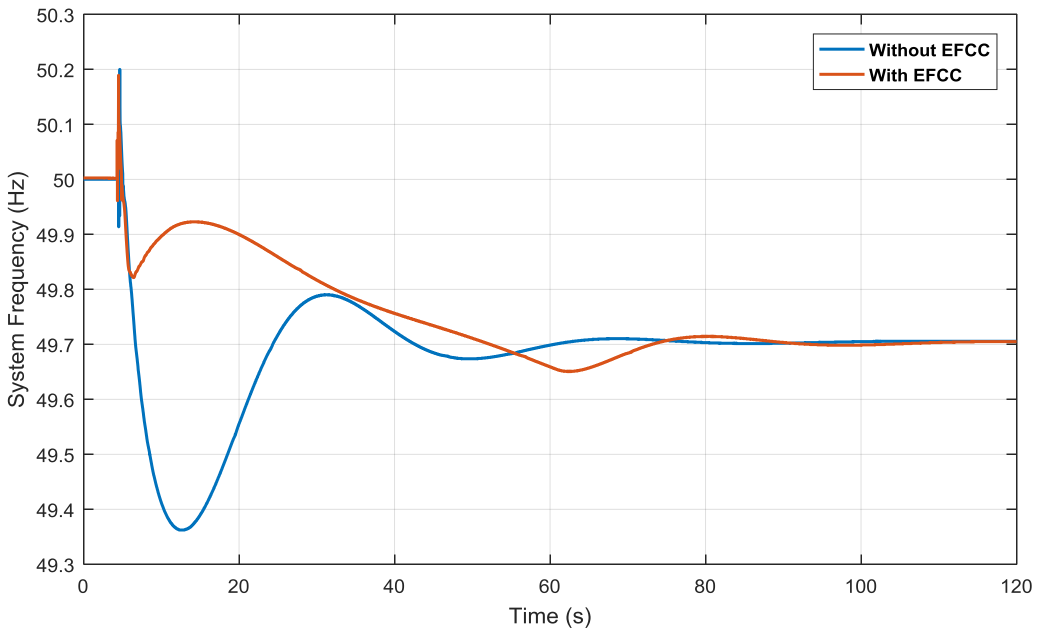

Figure 4-36 System frequency of generator tripping (Asyn at bus 5) after fault at bus 5 in zone 1

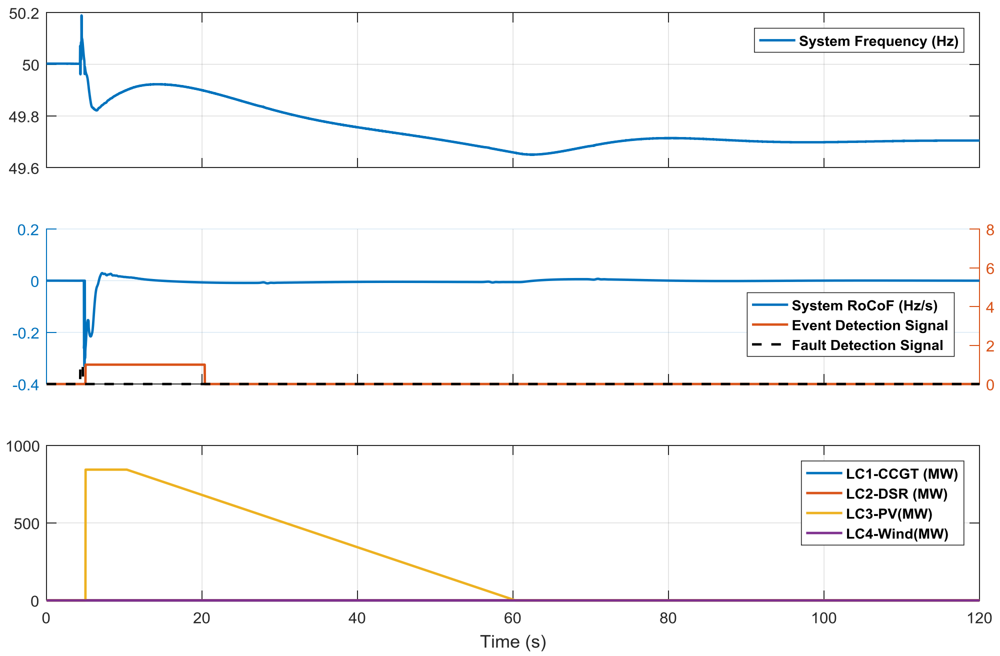

Figure 4-37 System frequency of generator tripping (Asyn at bus 5) after fault at bus 5 in zone 1

In this case, a 140 ms single phase ground fault is applied at bus 5 and then a generator (100MW) at bus 5 is tripped. As shown in the figure, similarly to the cases with load connection, the fault is detected, and event detection is enabled after fault cleared. The amount of request power from PV is 850 MW.

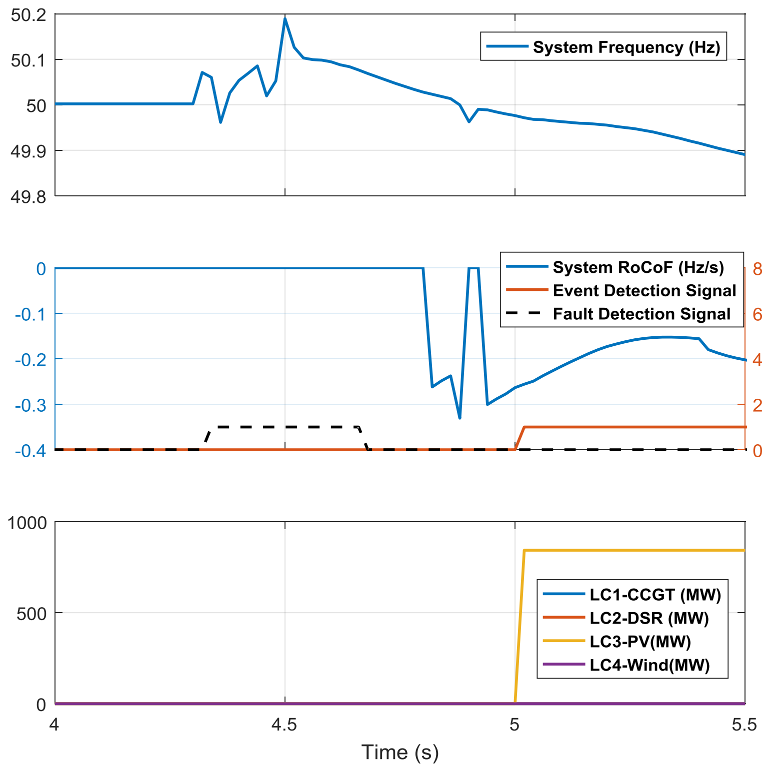

Figure 4-38 System frequency of generator tripping (Asyn at bus 5) after fault at bus 5

Learning Outcomes:

- The scheme is able to accurately detect and respond to events that occur in the aftermath and faults.
- The scheme is secure against line disconnection after a fault.

4.4 Sensitivity analysis

sensitivity analysis is conducted along the previous test cases. Various parameters in Phasor Controller and the scheme are selected, e.g., PMU weights, Ramping rate of service provider, Response time of service provider and Fault detection blocking time. Through all these test, the impact of key parameters is analysed and the robustness of the MCS is validated.

4.4.1 Impact of PMU weights on system frequency by comparing f_{coi} from RTDS

In this test case, PMUs are weighted in two ways. The first one is to equally set all weights to 25. The second one is to calculate weights based on the generator inertia connected at the same bus, described in previous chapter. The COI frequency is derived from RTDS and based on the generator speed which represents system frequency most accurately. To illustrate the difference, a 1000 MW load is connected at 12 second.

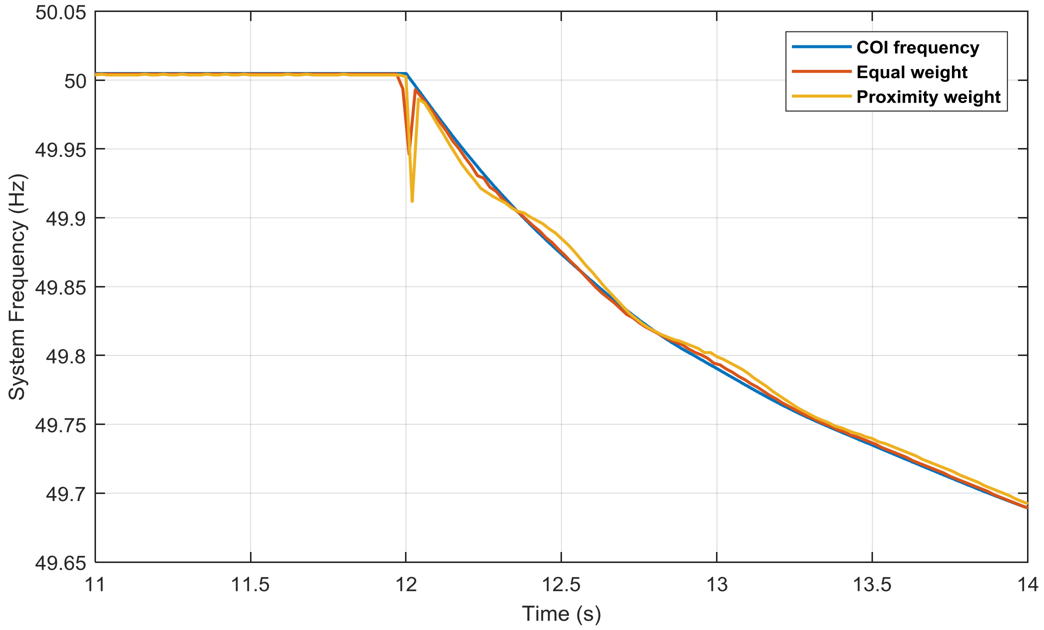

Figure 4-39 System frequency of different PMU weight configuration

It is noted that the transient spike at the beginning of the event is both observed in both PMU weighting method. But that equal weighting is removing more of the oscillation in the frequency while the proximity weighting shows more frequency oscillation. The reason to see such results is that we have limited number of PMUs (total 8 out of 25 buses) due to the limitation of available RTDS resources. It is suggested to further investigate the impact with a higher number of PMUs and the optimal way to place PMUs in the system for future study. On the other hand, the visibility can be influenced by the location of the disturbance. Especially in this case, there is one PMU having a higher weight located at disturbed bus, therefore the oscillation at this particular bus is introduced to the aggregated frequency.

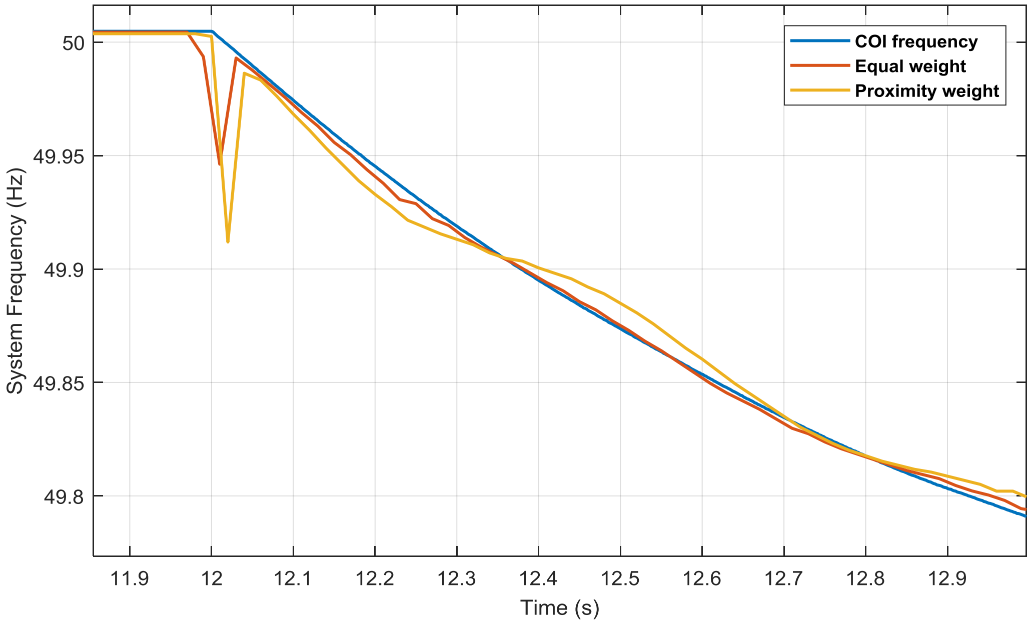

Figure 4-40 System frequency of different PMU weight configuration (zoomed)

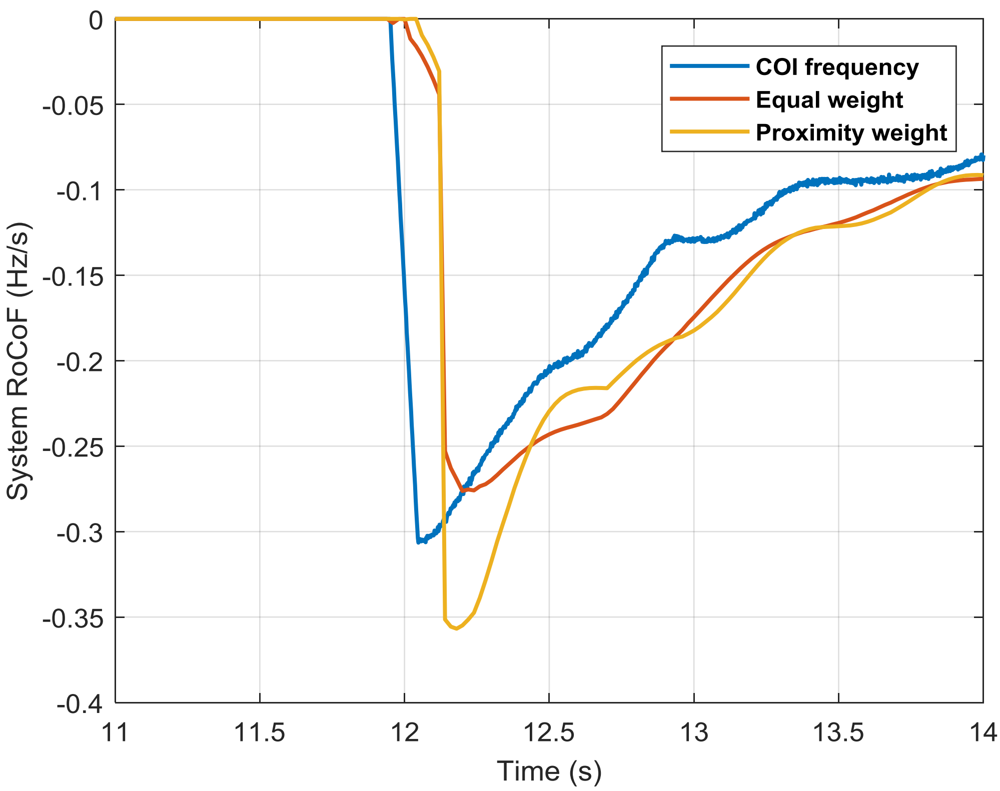

Figure 4-41 System ROCOF of different PMU weight configuration (zoomed)

In Figure **4-41**, the difference of two PMU weight setting method is clearly shown. For the equal weight method, the RoCoF is underestimated to the actual COI value.

4.4.2 Impact of minimum fault blocking time on event detection after a short circuit fault

To overcome the problem encountered in the fault test cases, a sensitivity analysis is conducted on the parameter sFltOffHyst. It defines the minimum fault blocking time when detecting a fault. By increasing it, we can block the event detection for longer period and wait the system to settle down.

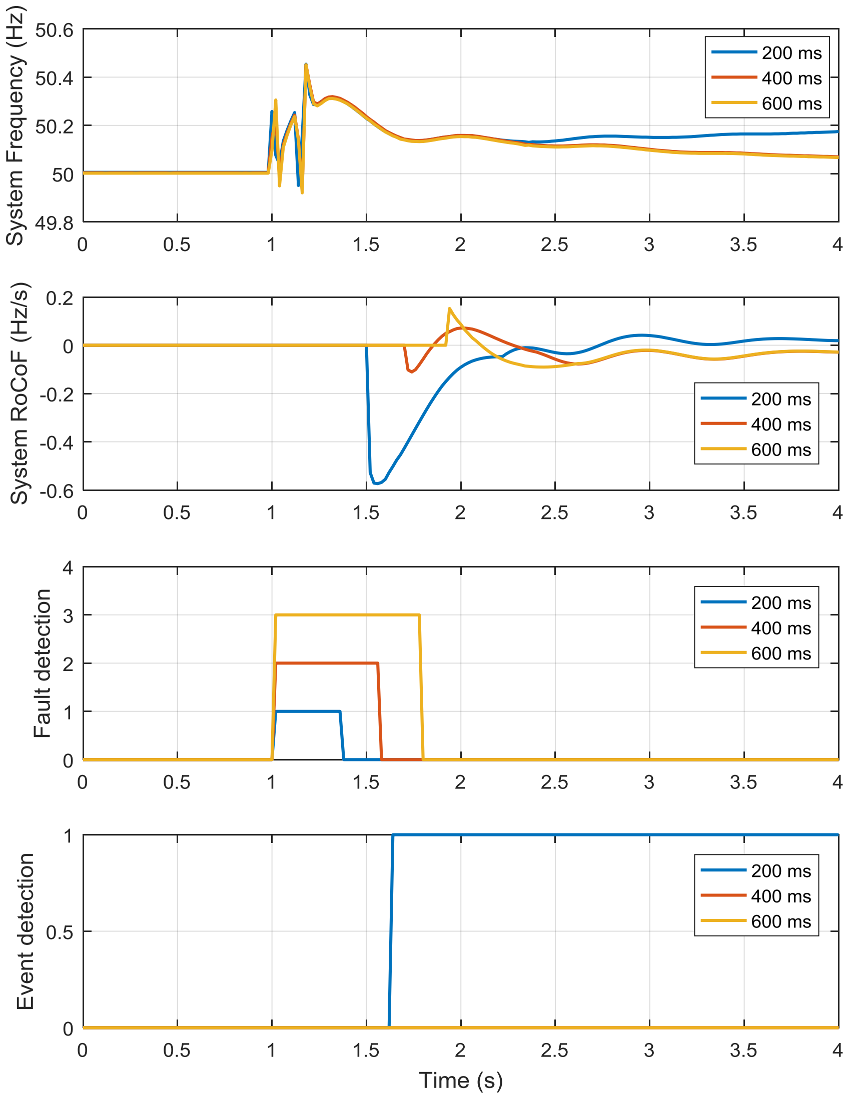

Figure 4-42 Sensitivity analysis of fault off hypnosis time after a three-phase fault at bus 5

A three-phase fault is applied at bus 5 with different sFltOffHyst setting at 200, 400 and 600 ms. It can be seen in Figure **4-42** that the fault detection period is prolonged. The Y axis value has no actual meaning but just to make the figure clear. With 200 ms, the impact of three phase fault can make event detection mis triggered. By increasing it, the problem can be solved however causing undesired delay of the scheme.

4.4.3 Impact of amount of service provider response

In this case, availability of PV is set to 200, 400, 600, 800, 100 MW respectively as shown in Table **21**. All other service providers are disabled in order to provide exact amount of response. The ramp rate of PV is 1000 MW/s.

In the simulation, at t=5 s, a 1000 MW load is connected at bus 1 and frequency will drop to 49.35 Hz if there is no MCS enabled. Then MCS is activated and configured with different amount of available power.

Table 22 Availability of service providers

	Service provider	Available power positive (MW)
Zone 1	DSR	0
	PV	200, 400, 600, 800, 1000
Zone 2	CCGT	0
	Wind	0

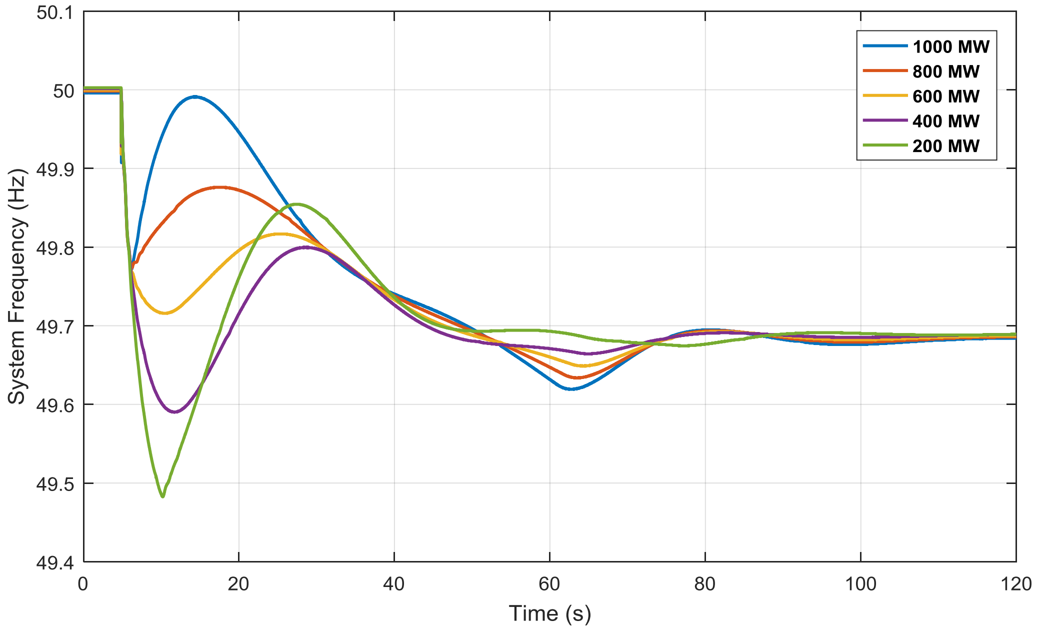

Figure 4-43 Sensitivity analysis of amount of service provider response

Figure 4-43 has shown the frequency behaviour with different amount of service provider response. It is noted that only when availability is extremely limited to 200 MW, 49.5 Hz limit is violated. For all the other cases, the frequency declining is effectively stopped and the frequency remains in the safe zone. The amount of service provider response in each case is shown in Figure 4-44.

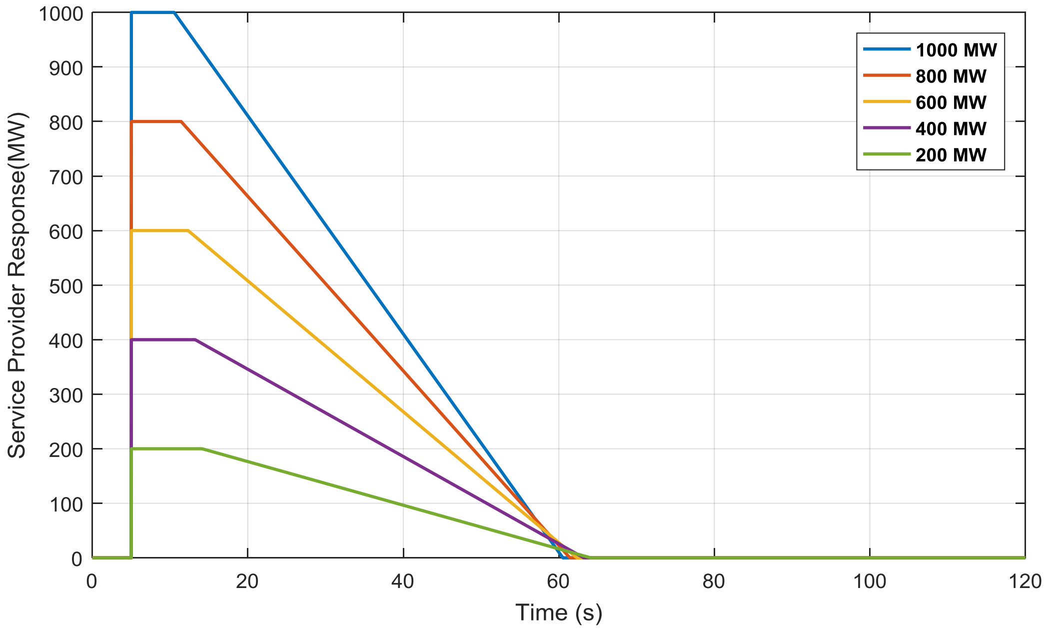

Figure 4-44 Amounts of service provider response requested

In conclusion, it is highlighted that even though larger response always gives better result in terms of frequency nadir, given the flexibility of EFCC, a moderate amount of frequency response could also offer an acceptable result with less amount of response and frequency nadir constrained above 49.5 Hz.

4.4.4 Impact of ramping rates of service provider

In this case, availability of PV is set to 600 MW. All other service providers are disabled in order to provide exact amount of response. The ramp rate of PV is set to 200, 400, 600, 800, 1000 MW/s respectively.

In the simulation, at t=5 s, a 1000 MW load is connected at bus 1 and frequency will drop to 49.35 Hz if there is no MCS enabled. Then MCS is activated and configured with different ramping rate.

In Figure 4-45, the frequency behaviour with different ramping up rates of service provider response is given. It is noted that when ramping up rate is above 600 MW/s, the difference becomes not obvious. However, if ramping rate goes below 400 MW/s, which means service provider will take 2 to 3 seconds to reach target output, low ramp rate results a lower frequency nadir, in this case 49.62 Hz with 200 MW/s. In addition, a higher overshot is observed for 200 MW/s case because of the delayed response will be effective at the same time with traditional governor control of synchronous generators in the system.

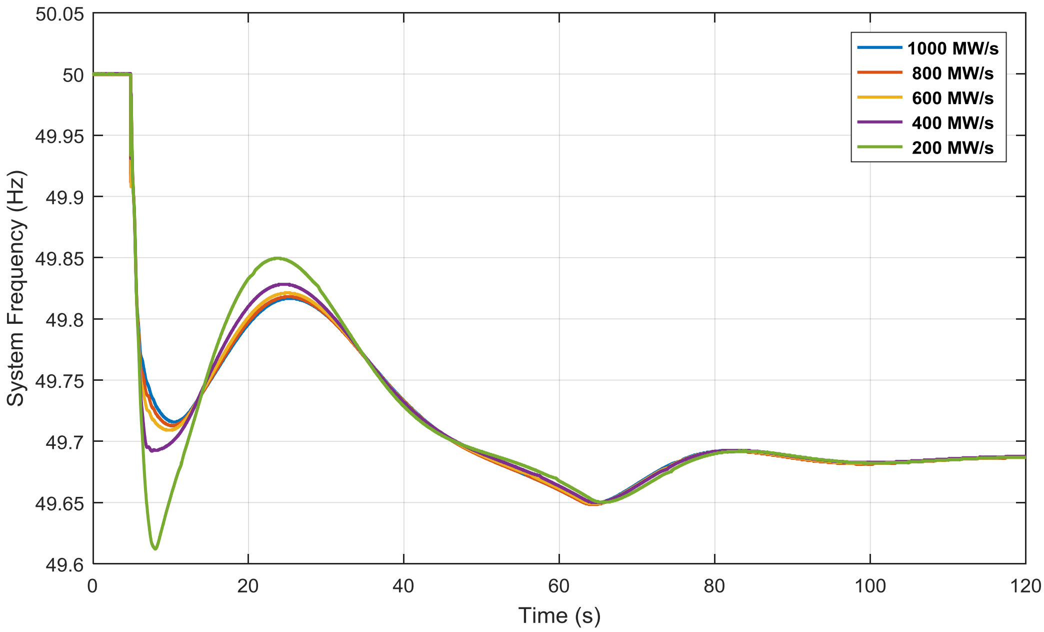

Figure 4-45 Frequency response of different service provider response ramping rates

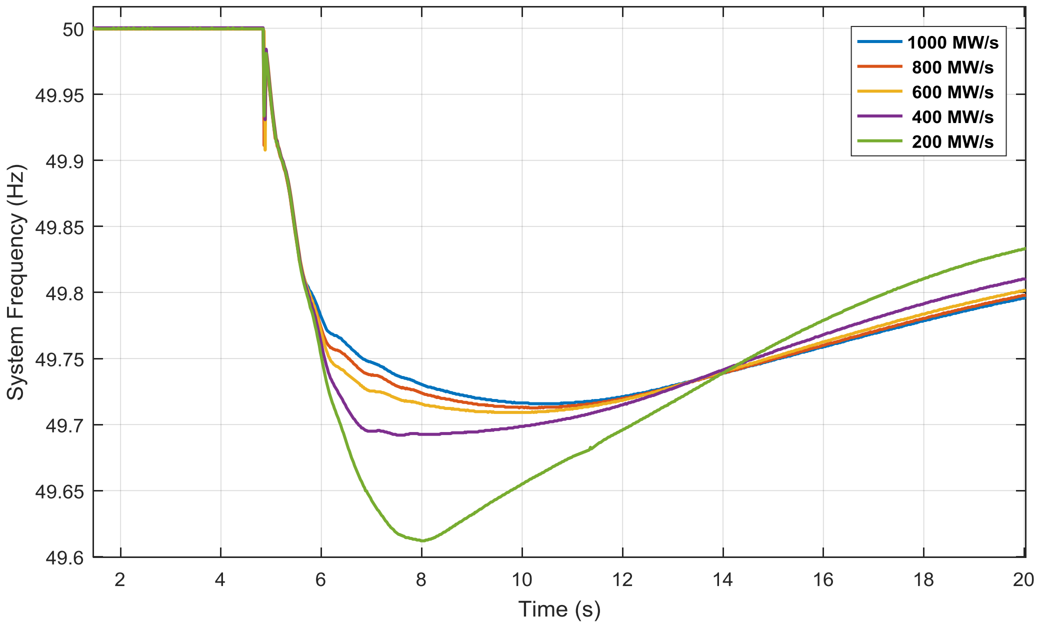

Figure 4-46 Frequency response (zoomed) of different service provider response ramping rates

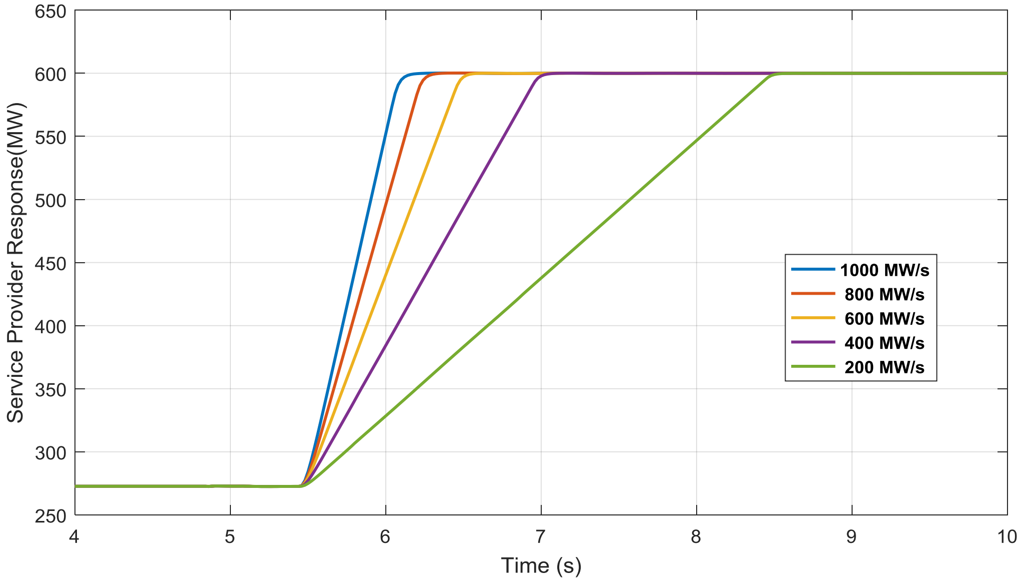

Figure 4-47 Actual service provider response with different ramping rates

In conclusion, it is highlighted that a very high ramping rate is not always necessary however in future lower inertia scenario, a high ramping rate of service response would be required. It also points out that the handshake between service provider and generator governor should be properly coordinated.

Limitation

The RTDS facilities are one of the very best in the UK, but each such test system has its limitations when it comes to the complexity of the test system.

This test uses a GB network test system that is designed to be representative of the GB system. however, a number of zones (compared to the 36 zone) is reduced in the RTDS model, allowing the incorporation of more complex resource models.

In each zone, only one aggregate synchronous generator can be modelling to represent a mix of different types of generators.

The number of virtual PMUs is also limited by the hardware availability, resulting a 4 PMUs for each region which has compromised the accuracy of the frequency and angle aggregation.

Load increasement instead of synchronous generator tripping is used to create low frequency event considering the limitation of the hardware and system stability.

By this the limitation of the test has been addressed.

Conclusions

A representative Real Time Digital Simulation model of the GB transmission system which may be used to test the operation of the GE Measurement & Control Scheme (MCS) and its associated architecture in deploying resources. Dynamic load and generation models representative of those resources upon the GB transmission system and embedded within the distribution networks are considered. The inertia condition is configured to reflect future transmission system levels of inertia, generation technology and demand type.

By developing hardware interface using industry standard communication protocol with which to enable the input and output to the MCS controller as well as time synchronization using GPS signals.

A range of Wide Area Mode analysis of system disturbances and conditions upon the GB transmission system model is conducted, and the GE MCS performance is assessed in relation to these events.

MCS performance is compared against the performance of the system without the MCS. The MCS performs as expected and robustly.

- The scheme is verified to deliver the appropriate MW response
- The scheme is verified to locate the disturbance in the right region
- LC responses follow the hierarchy – that is the order in which individual resources will be deployed.
- The scheme is able respond to the disturbance in the system when faced with an insufficient volume
- The scheme can effectively contain events that traditional services could not, however in doing so the pullback of the scheme needs to be coordinated with primary response and other frequency responses in the system.
- The scheme is secure against short circuits with consideration of practical duration and different fault type and locations.
- It is observed that a very severe fault. The voltages at different buses during fault are widely depressed and strongly impacted the system. It can actually lead the scheme to trigger. Some parameter like minimum fault blocking time can be used to resolve this problem.

In the sensitivity analysis, it is highlighted that a larger and faster response is not always better as it leads to greater sustained oscillation. With fast coordinated response of the scheme, a moderate amount of fast service response can effectively counteract the frequency contingencies.

It is also noted that the effect of disturbances is seen differently in relation to the location and proximity to PMUs used for the MCS. And this informs both the scope of PMU deployment and proper assigned PMU weightings within the MCS are needed.

The use of hardware-in-the-loop via the RTDS testing and the novelty associated with the control scheme is validated, proving fast-acting frequency-based wide area control which has not been deployed in GB yet associated with all new format of testing and simulation.

Future works

It is suggested that a bigger scale of the HiL test can be done in the future if larger RTDS facility and more number of phasor controllers are available.

Based on increased hardware capability, the number of regions can be increased more than current number and the total number of PMUs are suggested to be higher.

Due to the large number of parameters in the MCS and limited time of the project, it is also suggested that further sensitivity studies can be conducted in the future in order to investigate the impacts of other parameters and the possible optimal setting for the GB system.

References

1 GE EFCC document “Specification Event Detection” (NG-EFCC-SPEC-001)

2 GE EFCC document “Specification Control Platform” (NG-EFCC-SPEC-002)

3 GE EFCC document “EFCC Partner Interface Proposal” (NG-EFCC-SPEC-007)

4 GE EFCC document “Specification Resource Allocation” (NG-EFCC-SPEC-010)

5 UoM-EFCC report, “System studies of an appropriate GB network without Monitoring and Control Scheme (MCS) in PowerFactory”

6 GE EFCC document “Optimisation Functional Specification” (NG-EFCC-SPEC-004-FS)

7 UoM-EFCC report, “System studies of selected and known test networks in RTDS”, 23/03/2017

Appendix a: Service provider settings

Table 23: Information of service providers used in the test

Response characteristics	CCGT-LC1	DSR-LC2	PV-LC3	Wind-LC4
Region index	2	1	1	2
Positive available power	200	200	1000	300
Negative available power	300	0	1000	200
Response time for positive power (T^{+}_{delay})	0.3	N/A	0.1	0.1
Response time for negative power (T^{-}_{delay})	0.3	N/A	0.1	0.1
Response rate of positive available power ($RespRate^{+}$)	300	N/A	1000	1000
Response rate of negative available power ($RespRate^{-}$)	300	N/A	1000	1000
Response duration of positive available power ($T^{+}_{duration}$)	20	30	10	10
Response duration of negative available power ($T^{-}_{duration}$)	10	N/A	10	10