GE Digital

Distributed ReStart Deliverable 1

DRZC Design and Testing Specification

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imagination at work

Contents

Glossary

Acronym	Description
ADMS	Advanced Distribution Management System
AFB	Application Function Block
BaU	Business as Usual
BESS	Battery Energy Storage System
CLPU	Cold Load PickUp
CT	Current Transformer
DER	Distributed Energy Resource
DNO	Distribution Network Operator
DRZC	Distributed ReStart Zone Controller
DSO	Distribution System Operator
EMS	Energy Management System
FAT	Factor Acceptance Testing
FBD	Function Block Diagram
FMEA	Failure Mode and Effects Analysis
GPS	Global Positioning Satellite
H	Generator inertia constant
HiL	Hardware in the Loop
HW	Hardware
IED	Intelligent Electronic Device
IL	Instruction Lists
LAN	Local Area Network
LD	Ladder Diagram
LoM	Loss of Mains
LOPA	Layers of Protection Analysis
M&S	Maintenance and Support
MITS	Main Interconnected Transmission System
MMS	Manufactured Message Specification
MTBF	Mean Time Between Failure

MTTR	Mean Time To Repair
NGESO	National Grid Electricity System Operator
NTP	Network Time Protocol
OLTC	On Load Tap Changer
PBC	Primary Balancing Control
P-class	Protection Class
PDC	Phasor Data Concentrator
PhC	Phasor Controller
PLC	Programmable Logic Controller
PLL	Phase Locked Loop
PMU	Phasor Measurement Unit
PR	Proportional Regulation
PRP	Parallel Redundancy Protocol
PTP	Precision Time Protocol
r-GOOSE	routable Generic Object Orientated Substation Events
RoCoF	Rate of Change of Frequency
RPN	Risk Priority Number
SAT	Site Acceptance Testing
SBC	Secondary Balancing Control
SFB	Service Function Block
SFC	Sequential Function Chart
SiL	Software in the Loop
SIPS	Special Integrity Protection Schemes
SLA	Services Level Agreement
SPEN	Scottish Power Energy Networks
SS	Substation
ST	Structured Text
SW	Software
T&M	Time and Materials
TCP	Transmission Control Protocol
TO/TSO	Transmission Owner/Transmission System Operator
UDP	User Datagram Protocol

UFLS	Under Frequency Load Shedding
UI	User Interface
VPP	Virtual Power Plant
VT	Voltage Transformer
WAMS	Wide Area Management System
WAN	Wide Area Network

1 Executive Summary

GE seeks to deliver a Distributed ReStart Zone Controller (DRZC) solution to enable Scottish Power Energy Networks (SPEN) and their project partners to monitor, coordinate and control a range of DER and conventional resources to provide suitable Black Start services to National Grid Electricity System Operator (NGESO). This is a key part of the Power & Engineering Trials (PET) workstream of the Distributed ReStart NIC funded project. This document outlines the design and testing specifications for the DRZC with descriptions of each function and how they are connected to deliver the overall system.

Section 2 describes the overall DRZC system architecture including the main components, interfaces and communications protocols

Section 3 states the main assumptions around the DRZC design from GE's perspective.

Section 4 covers the main functional design including the key functional blocks, test results and supporting functions and systems.

Section 5 describes the non-functional specifications related to FMEA, design processes, testing methodology and lifecycle management.

BaU rollout costing, DRZC equipment specifications, list of standards and additional test results are included in the Appendices.

This report forms **Deliverable #1** of the DRZC project and should be read in conjunction with the other two reports being delivered by GE [1] [2].

1.1 Project Background

The Distributed ReStart project is a three-year programme (Jan 2019 – Mar 2022) that will develop and demonstrate new approaches to enabling Black Start services from Distributed Energy Resources (DER).

Case studies on the SP Distribution (SPD) and SP Manweb (SPM) networks will be used to explore options and then design and test solutions through a combination of:

- Detailed off-line analysis
- Stakeholder engagement and industry consultation
- Desktop exercises
- Real-life trials of the re-energisation process.

The GE DRZC design focussed on the Chapelcross 33kV system for the initial design. Simulated data across a range of restoration options and system conditions were used to design and test the core control scheme. The Chapelcross DRZC is built around Stevens Croft wood-fired power plant that provides the necessary anchor generation to restart the island. A load-bank is also used to provide minimum loading of the plant and for frequency control during later block loading stages.

However, the functional design outlined in this report can be applied to any distribution system where a range of DER and anchor generation can be configured. For example, other DRZCs may use hydro as the anchor technology with a battery installed to provide minimum loading. The GE DRZC design will focus on two specific project areas within the wider NIC project including:

Power engineering and trials (PET)

The power engineering and trials work stream is concerned with assessing the capability of distribution networks and installed DER to deliver an effective Black Start service.

The GE DRZC will provide the automatic control mechanism to oversee the process of establishing and maintaining the DRZ power island. It will manage island generation and load to balance the frequency and maintain the system operation within protection limits.

Organisational, systems and telecommunications (OST)

The organisational, systems and telecommunications work stream will consider the restoration process including different roles, responsibilities and relationships needed across the industry to achieve Black Start from DER at scale.

The functional design description contained in this document relates to the PET section with deliverables 2 & 3 (communications & cybersecurity, systems integration) relating to the OST section.

The DRZC sits within the automated organisational models outlined in the OST documentation. The DRZC design manages the DRZ frequency stability and supervises synchronisation. In the case of the two extreme automated organisational models, the use of automation is extended beyond the proposed DRZC design. In these extreme models, an automated control system interfaces directly with DNO and DER systems to perform tasks such as network reconfiguration, management of protection & control settings, and generator dispatch. This additional automation is beyond the proposed GE DRZC scope. However, the DRZC could support a more automated control model.

1.2 Wider organisational and technical context

The DRZC design proposed in this document will enable distribution power islands to be established that will improve the overall security of supply and reliability in the event of a Blackout. This will be achieved in a number of ways:

- Managing stability of low inertia power islands through capability assessment of load pickup, managing unplanned events, e.g. load tripping, and supervising resynchronisation. This speeds up the restoration process and reduces the risk of returning to a Black start scenario
- Safely integrating more DER into the Restart process to restore more customers more quickly at distribution level
- Enabling provision of restoration services to NGESO once a DRZ is ready for resynchronisation

Table 1 below outlines the DRZC impact on restoration times in more detail.

Function / Area	Description	Impact on restoration
Assessing block loading capability	Ensuring block load is kept below system capability (mainly anchor generation RoCoF and frequency limits)	Reduces risk of tripping anchor generation Allows DNO control room staff to plan load pickup more effectively, i.e. potentially splitting loads to avoid generator tripping

Managing unplanned events	In the event of generation or load loss the DRZC will manage the anchor generation via fast balancing control to reduce risk of tripping	Avoid returning to Black start scenario and increasing overall restoration times
Managing island frequency reserves	Slow balancing manages both anchor and flexible demand reserves to ensure adequate frequency regulation is maintained	Reduce stress on anchor generation and improve chances of multiple load pickups
Managing island resource	Resource manager monitors the status of the DER e.g. windfarm Power Available, to ensure enough resource is available to grow the island	Maximise the efficiency of the island resource and optimises the load pick-up which may be a larger number of smaller load pickups (within the block loading capability). These can be picked up faster leading to overall reduced restoration times.
MITS restoration	Direct resynchronisation to MITS once DRZ is ready. Multiple DRZC zones may resynchronise with MITS independently.	Restarting and balancing multiple zones for eventual MITS resynchronisation while reducing the DNO operator workload. Improved chance of resynchronisation through monitoring of voltage angle and frequency difference and supervising resynchronisation.
Parallel power system restoration	Enabling resynchronisation across DRZC zones before further MITS resynchronisation. Allows more resource to be aggregated to provide larger service to NGESO and supply more customers	Restarting and balancing multiple zones for neighbouring DRZC resynchronisation while reducing the DNO operator workload. Improved chance of resynchronisation through monitoring of voltage angle and frequency difference and supervising resynchronisation. Eventual resynchronisation to MITS providing larger VPP capability
WAMS monitoring	Custom views to support all stages of the ReStart process, from Blackout to grid-connected operation	Cross-validation of ADMS signals to ensure the system restoration is progressing as expected
ADMS integration	Key information exchanged with ADMS to keep DNO control room staff up to date on the restoration	DRZC provides a range of information to speed up restoration including block load

		pickup capability, event detection and resynchronisation information
Multiple DER involvement	DRZC can manage a large number of resources, opening up the market for more DER to participate	More DER participants increases island capability and capacity leading to higher number of customers being reconnected and a potentially more capable transmission restoration service for NGESO

Table 1 DRZC impacts on overall restoration times

2 Revision List

VERSION	DATE COMPLETED	CHANGE OWNER	CHANGES
V1	7th August 2020	P. McNabb	Original version
V2	31st August 2020	P. McNabb	(REDACTED). Numerous revisions outlined in change tracker document

3 Solution Architecture

The high-level architecture of the DRZC and associated systems in shown in Figure 1. The communication paths and protocols are shown with a unique colour key as well as the main measurement locations and monitoring systems. The control system relies on fast, synchronised measurements at key resource locations to enable sub-second control actions. Sub-second control is necessary to manage frequency and Rate of Change of Frequency (RoCoF) in the low inertia conditions of the DRZC island.

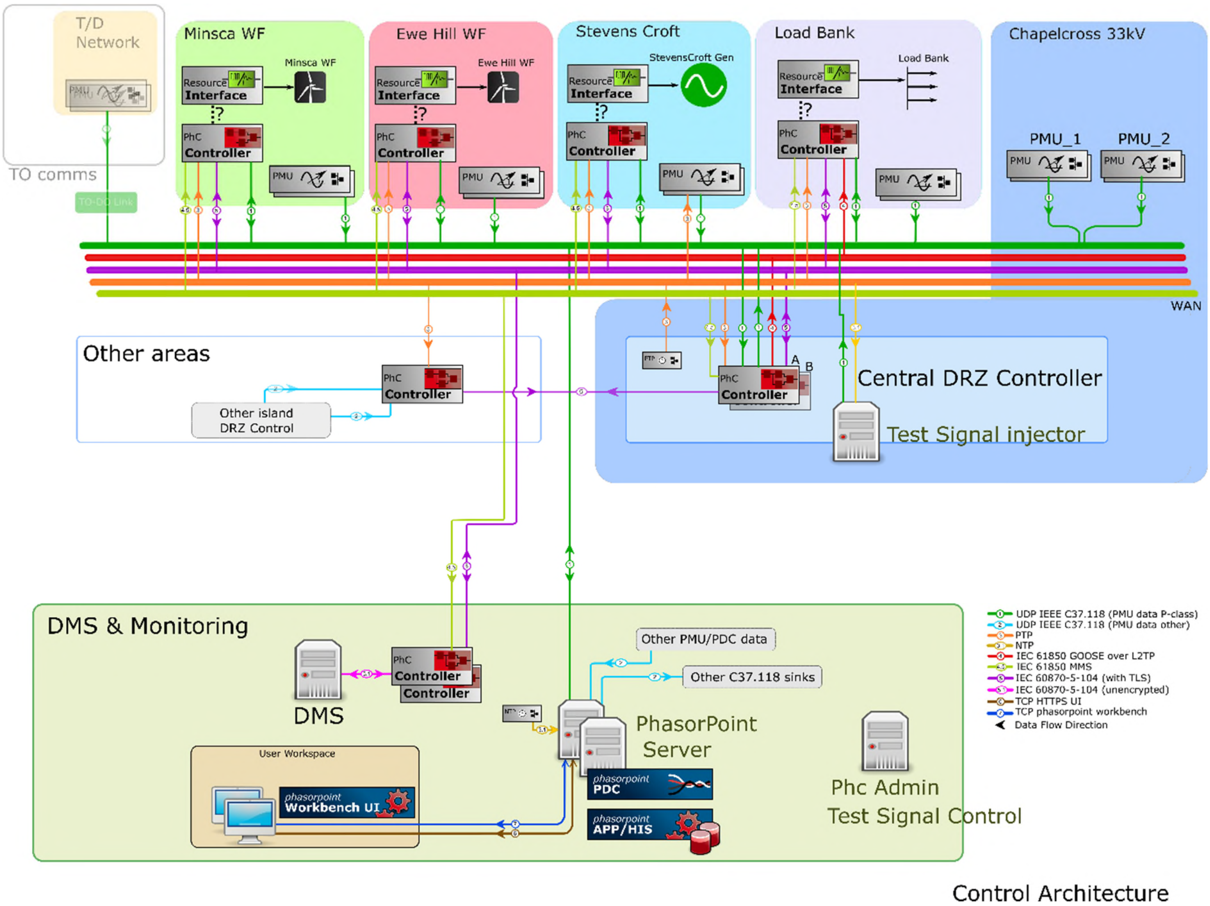


Figure 1 High level DRZC solution design including key components, links and communications protocols

The main components of the scheme shown in Figure 1 are described further in Table 2, based on Chapelcross 33kV network:

Component	Location	Function
Phasor Measurement Unit (PMU)	Main Interconnected Transmission System (MITS) Stevens Croft Load Bank Minsca WF Ewe Hill WF	Measure V&I phasors + frequency at 50FPS, streamed to main DRZC controller (Chapelcross 33kV SS) and central WAMS server. Data is streamed in real-time across the network as defined

	Chapelcross 33kV SS	by UDP IEEE.C37.118 protocol. PMUs should be configured as P-class to reduce measurement latency
Phasor Controller (PhC)	DNO Control Centre Stevens Croft Load Bank Minsca WF Ewe Hill WF Chapelcross 33kV SS	Chapelcross 33kV PhC hosts the main DRZC scheme. Control signals are relayed to resource via a range of protocols depending on latency requirements (IEC 61850 GOOSE, IEC 60870-5-104). It can also act as a PDC to forward measurements to other locations e.g. TO/TSO Other PhC locations handle encryption and protocol conversion etc. as per cybersecurity requirements outlined in [1]
Resource Interface	Resource locations	Interface to resource control systems (within resource control system) that defines communications protocol
TO-DNO link	SPD to SPT/NGESO communications	Communications channel between DNO and TO/TSO to share PMU and DRZC data. GE PhasorPoint supports the SCADA protocol IEC-60870-5-104 for this purpose. Alternatively, the ADMS may support ICCP for data forwarding.
DMS	DNO Control Centre	Primary monitoring tool for overall ReStart process and sequences. Data point sent via PhC and WAMS over IEC 60870-5-104
Precision Time Protocol (PTP) Source	Chapelcross 33kV SS	Provides PTP signals to synchronise range of DRZC devices, based on IEEE-1588 protocol
EMS	TSO Control Centre	NGESO monitoring. Information exchanged

		between DMS and EMS to be defined based on organisational model [2]
NTP	DNO Control Centre	Provide NTP source for WAMS (PhasorPoint server)
WAMS server (PDC + Applications)	DNO Control Centre	Store PMU data and DRZC control status to enable DRZC scheme to be audited. Both TCP IEEE.C37.118 and UDP IEEE.C37.118 streams can be configured with data observed via the workbench UI. Relevant data can be streamed to DMS over IEC-60870-104
Workbench UI	DNO Control Centre	JWS UI linked to WAMS server over TCP HTTPS.
PhC Admin	DNO Control Centre	DRZC controller admin to manage settings and thresholds
Other DRZC	Other DRZ islands	Potential to link multiple DRZCs under one DNO region for possible distribution resynchronisation before transmission connection

Table 2 Description of key DRZC components (based on Chapelcross 33kV network). Communications protocols are discussed in more detail in deliverable 2

4 Assumptions and Prerequisites

Table 3 outlines the DRZC operating assumptions.

Assumption	Description
DRZ protection settings updated via DMS with DRZC control settings activated	The DRZC requires thresholds and settings to operate. GE have designed the DRZC based on G99 [3] settings with additional margins. The actual island protection settings will be less restrictive compared to the DRZC, to allow the DRZC to manage island frequency with protection operation activating as a last resort
Anchor generator as grid-forming source	A synchronous generator is always the grid forming source to enable load and DER to be connected. Power electronic converted generation may be used as grid-forming in the future but is assumed to be grid-following in this design
DER capability	The capability of the resource should be available via direct measurement and thresholding or directly from the resource where appropriate i.e. windfarm power_available. The exact requirements are outlined in Section 5. Information should be provided on the interfacing to the resources i.e. ability of the resource to take a trigger signal and a MW setpoint value
DER response	The DER response should match what is made available to the DRZC as closely as possible. Large imbalances could drastically reduce the effectiveness of the control actions and use up other resource unnecessarily.
DER Availability	Anchor generation and load bank will be available at a minimum. Certain DRZC functions (slow balancing) will only be activated if DER and primary load is available.
Max number of resources	The PhasorController is hard real-time embedded device that cannot be scaled indefinitely. The maximum number of resources that DRZC can handle would be subject to testing in the design phase. Resource includes DER, load bank, BESS and multiple primary circuits (load shedding).
DRZC only manages frequency-based constraints	The DRZC will only manage frequency-based constraints in the DRZ. Voltage and oscillation-related issues are not envisaged as a threat in the Chapelcross simulations. Voltage will be managed within limits by local control of DER. Additional constraints may be added in future if required.

DER operation in very low system strength and inertia systems	Enough system strength is available to enable DER to be connected. In future, the system strength and inertia could be estimated and compared against the DER requirements. DER control modes could be adapted to manage very low system strength conditions.
Maximum sustainable load and generation loss should be specified.	The DRZC will report load pickup capability before each load block, which can be compared to the maximum sustainable load and generation loss
PMU locations	PMU measurements are required at locations outlined in 5.8.1

Table 3 DRZC operating assumptions

5 Functional Design

5.1 Overview of Distributed Restart Zone Control Operation

The primary role of the Distributed Restart Zone Controller (DRZC) is to manage the frequency and balance of the island as it is energised, loaded, run as an island, resynchronised and restored to normal operation. During a Black start procedure, the island is operated in a low inertia state and frequency is very sensitive to changes in load and generation. There is inherent uncertainty in the volume of load picked up and the variations of load and renewable generation, and combined with low inertia, this leads to highly variable frequency. This is mitigated by the DRZC which applies a supervisory control to apply fast actions to rebalance the system in response to load pickup and unplanned trips of load or generation, as well as slower balancing actions that keep the frequency close to 50Hz and frequency regulation within the control band. The DRZC manages the island operation up to and including the resynchronisation process.

The DRZC primarily uses synchrophasor measurements for observability and control. This captures the dynamics and stability of the island and provides fast-acting response. The DRZC interacts with the controllable resources in the island (e.g. load bank, battery, dispatchable generation and sheddable loads). It also communicates with the ADMS, mainly for reporting functions and to receive basic commands.

There are four key processes performed by the DRZC:

Fast Balancing Detects large RoCoF events, translates to an island power imbalance and triggers a balancing action using the flexible MW demand.

Slow Balancing Detects the primary balancing resources (anchor generator and/or flexible demand) exceeding margins for regulating the power balance of the island and initiates rebalancing so that the anchor generator and load bank / battery return within the margins.

Resynchronisation Identifies island operation and reports the status of angle and frequency limits relative to acceptable limits for resynchronisation. The operator can use this indicator to determine if the island can be resynchronised. It also reports whether the resynchronisation is successful, leading to restoration of grid connected operation.

Resource Manager Tracks availability of resources according to the categories of positive / negative and fast / slow balancing services, aggregates and distributes Fast and Slow Balancing commands to physical plants. Reports the aggregated capacities to the operator.

According to the staged process [4], the DRZC is mainly used for control in Stages 3 through 6. The anchor generator startup is monitored with phasor measurements, and once the anchor generator is established and operating in frequency regulation mode, the control processes are enabled and operate through the network energisation, load pickup and island running stages, as well as supervising the resynchronisation.

Stage 1 The network is reconfigured for Black start using switching sequences and protection settings groups deployed from the ADMS. There is no DRZC involvement in Stage 1.

Stage 2 The anchor generator is started by a local process determined by the generator operator, monitored using phasor measurements. DRZC control functions of fast and slow balancing are initiated at the end of Stage 2.

Stage 3a Network energisation is observed using the phasor measurement infrastructure. Voltage control for network energising is achieved with local control without control intervention from DRZC. However, there is a risk of unplanned load or generation trips in the island during network energisation and the DRZC will maintain the power balance and frequency through such events.

Stage 3b Load and generation pickup sequences are initiated by the operator. The DRZC triggers load bank response using the Fast Balancing approach in order to keep ROCOF and frequency within acceptable limits. Slow Balancing

Stage 4 Island running requires frequency management processes to maintain a stable frequency and to ensure that sufficient regulating margin is available. During island running, load drift and renewable generation output change the balance of the island, resulting in the Proportional Regulation governor function at the anchor generator to change output. If the anchor generator output approaches the limits of its regulating capability, a rebalancing action is taken to adjust Primary Balancing Control (the load bank) if there is headroom, or Secondary Balancing Control (preferably DER dispatch; load trip if necessary). If a disturbance occurs during Stage 4, Fast Balancing can also be triggered if the event is severe, followed by Slow Balancing.

Stage 5 Resynchronisation requires angle and frequency differences to be measured at PMUs on each side of the resynchronisation boundary. An indicator is provided to the operator to show when the frequency and angle difference values are within the pre-set limits. Once the frequency difference is within limits, the operator can arm the synchrocheck relay. The operator can then observe whether the resynchronisation was successful or not, and if not, there is immediate feedback to improve the conditions for another attempt.

Stage 6 Once continued successful grid-connected operation is confirmed by DRZC (typically within around 10-15s), the anchor generator governor can be switched to constant power and fast and slow balancing processes can be disabled. Any other changes such as restoration of grid-connected protection and earthing can be initiated by the ADMS once the successful synchronisation check is received by ADMS.

A summary of the interactions between the key DRZC functions is illustrated in Figure 2. Further detail is included in the process flow in Figure 3 (Section 5.2) and in subsequent descriptions.

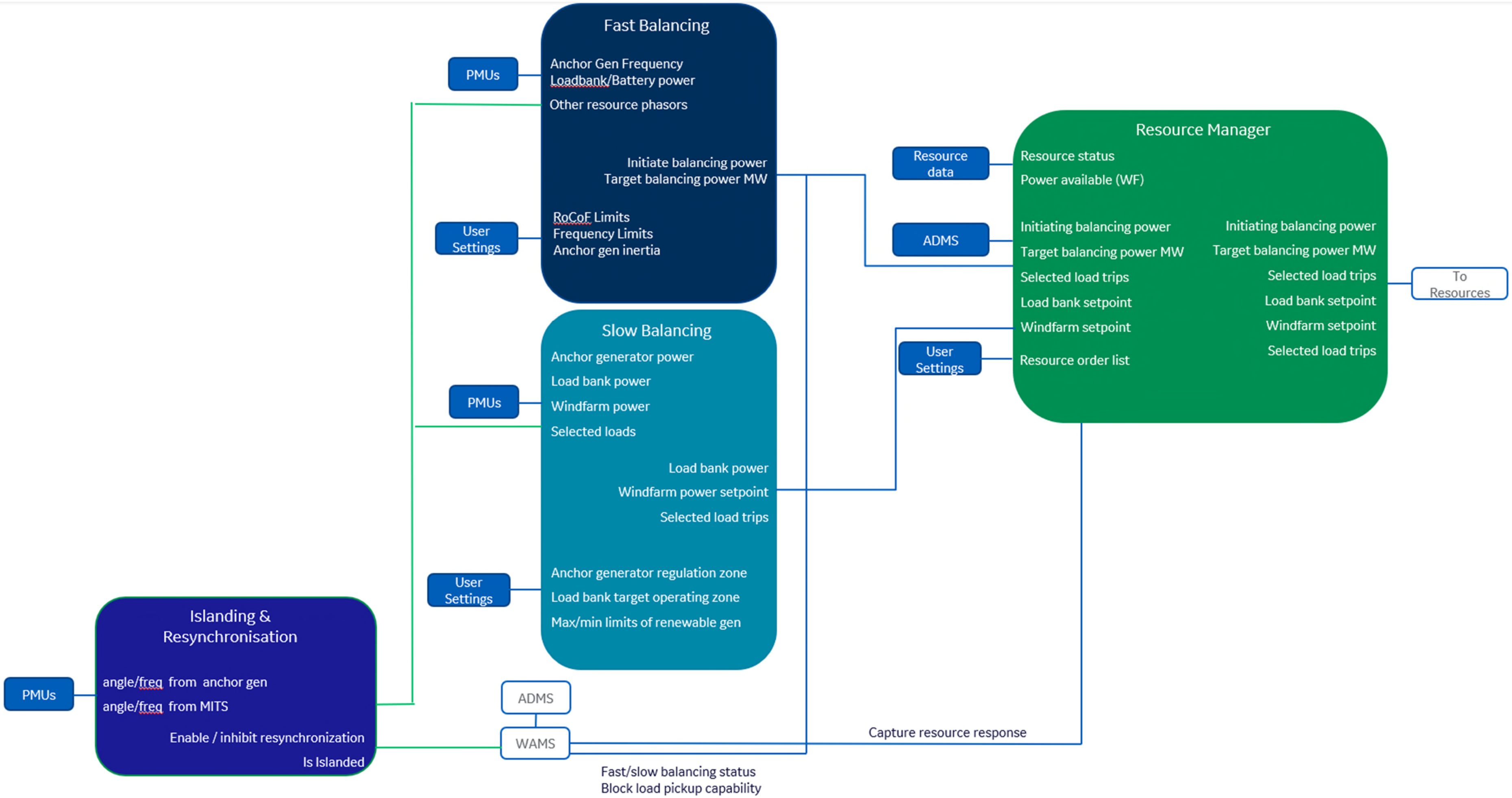


Figure 2 Information exchanges between DRZC Control Functions and with external systems

5.2 Integrated solution operation

The following description of the integrated restart process relates to the process flowchart in Figure 3 which is derived from [4].

5.2.1 Stage 1 Network Initialisation

Validate Zone Black

After the operator receives notification of a Black start service request, the operator then confirms that the zone is indeed blacked out. The WAMS UI provides confirmation that voltages and currents have zero magnitude. If any phasor is non-zero magnitude, this will be highlighted to the operator through the WAMS UI and corroborated with the ADMS system. Non-zero voltage magnitude within the zone will block the network initialisation in the ADMS.

Initialise Network

The network initialisation is carried out through the ADMS using programmed switching sequences and commands. There are two key functions performed by the ADMS:

1. Network switching schedule prepared to perform and confirm the network configuration to prepare for the Black start process.
2. Protection is reconfigured by dispatching commands to change protection to pre-determined settings groups.

These sequences are initiated by the operator through the ADMS in simple commands. Only the high-level command requires operator input and subsequent sequences are automated to relieve load on the operator and reduce potential for error. The operators will receive confirmation that the sequences have been successfully applied.

There is no input from the DRZC or WAMS UI in the network initialisation.

5.2.2 Stage 2 Anchor Generation Startup

The anchor generator startup process is applied locally without involvement by the DRZC, except to monitor the stability of the governor control. The anchor generator startup is initiated from the control room through the ADMS, but the process is managed locally by an automated or supervised process outside the scope of this report.

Anchor generator startup is complete once it is observed at the generator substation that:

1. Terminal voltage is near-nominal and stable
2. Frequency is near-nominal and stable, with no “hunting” oscillations
3. Governor droop control is enabled
4. Anchor generator power is within its Trim_Margin limits (covered in detail in Section 5.4.1)
5. Load bank power is within its Trim_Margin limits

A WAMS view is required that will allow the operator to easily confirm that these conditions are satisfied. The operator can then initialise Fast and Slow Balancing in the DRZC.

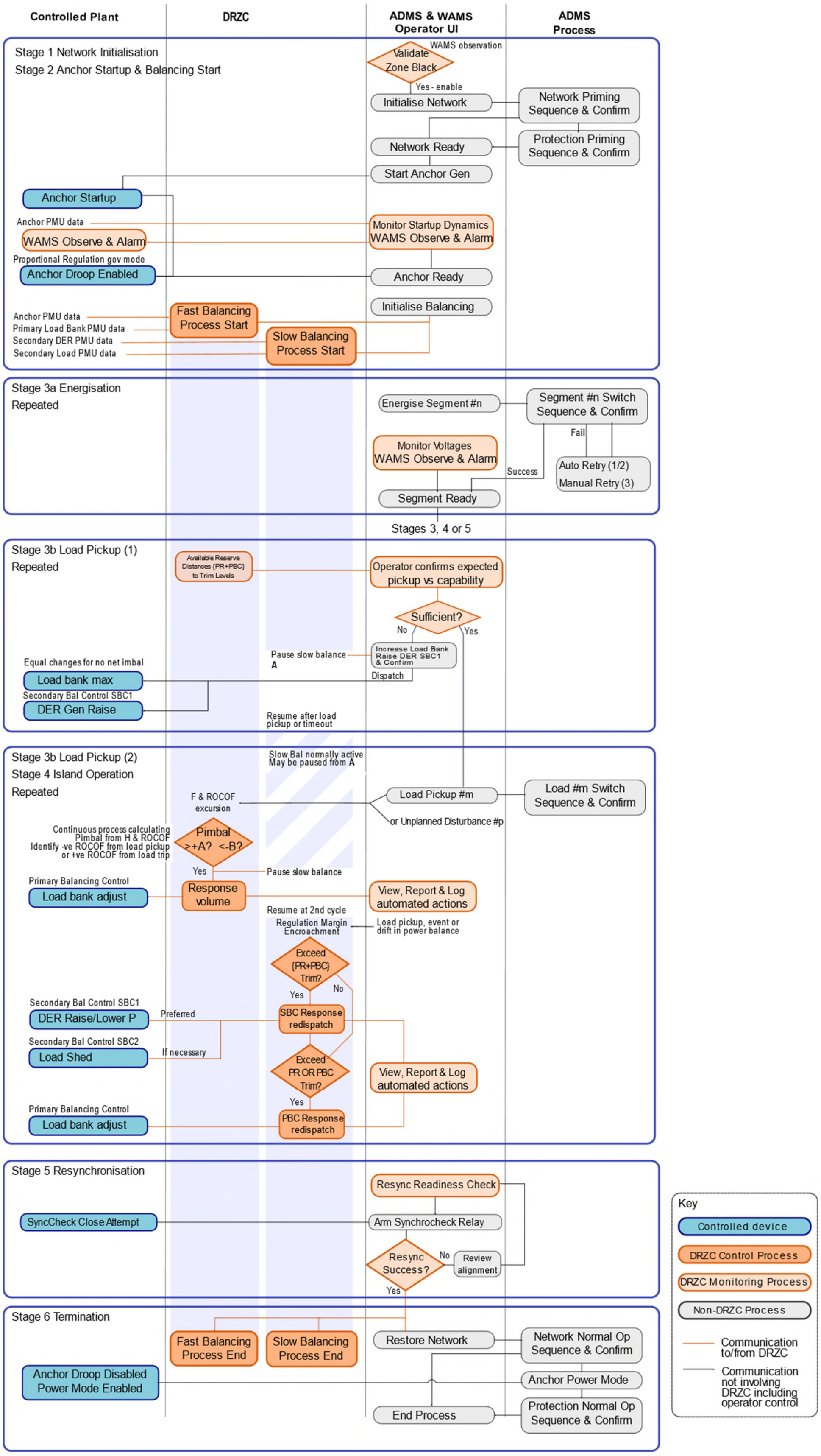


Figure 3 Integrated Distributed Restart Process Flow including DRZC Functions

5.2.3 Stage 3-4 Energising and Island Running

During Stages 3 and 4, the Fast and Slow Balancing processes manage the frequency stability during disturbances and ensure that a balancing margin is maintained in the anchor generator, load bank and/or battery (if available). The Fast and Slow Balancing processes are enabled at the end of Stage 2 and run continuously until resynchronisation, with the exception of pauses in Slow Balancing to allow for intentional dispatch of the load bank outside the Trim_margin limits.

Stage 3a involves energising segments of the network. This requires sufficient system strength and reactive control capability to keep voltage within operational limits. Voltage regulation is achieved by local control systems including the anchor generator AVR operating in voltage droop control and transformer tapping. There is no direct participation of the DRZC in voltage control, but the operator is able to observe and record the voltage at PMU measurements and reactive power deployment from locally controlled devices. A WAMS view is useful to confirm the stability of voltage as network segments are picked up.

Stage 3b is active power load pickup. Prior to load pickup, the operator will confirm using a WAMS UI view and the expected load pickup that there is sufficient regulating and primary balancing resource, as described in more detail in Section 5.4. Primary balancing resource is required to avoid violating RoCoF limits, while proportional regulation capacity (i.e. anchor governor frequency control) is required to keep frequency within limits.

Normally, load pickup can be achieved by the operator simply by initiating an automated switching sequence. However, if there is insufficient fast-acting Primary Balancing Control at the load bank, it may be necessary to increase the load bank power level if the likely load pickup exceeds the acceptable limits. To do this, Slow Balancing is suspended while the load bank is maximised and the load pickup operation is carried out.

Slow Balancing will also use a prioritised list of Secondary Balancing Control resources, normally through DER raise/lower commands and occasional use of load tripping (as a last resort). These resources are used when required to restore the balancing margins after an encroachment of margins.

Stage 4 is continuous island operation. The same Fast and Slow Balancing methods are used to manage frequency through the period of island operation. The load bank and/or battery (the primary balancing resources) and the anchor generator (proportional regulation) maintain a margin to control changes in the island power balance. If the margin on the primary balancing or proportional regulation are encroached, then Secondary resources are deployed to restore the margins.

Stages 3a, 3b and 4 do not need to be sequential. Network and load pickup can be applied flexibly according to processes that may be selected according to the prevailing conditions in the network. The island is also robust against unplanned disturbances while operating in conditions where frequency is volatile and potentially unstable.

5.2.4 Stage 5 Resynchronisation

Successful resynchronisation depends on the alignment of frequency and angle differences. Fast and slow balancing will act to maintain a stable frequency in the grid, and visualisation is available to the operator to indicate when the resynchronisation conditions are met. At this point, the operator can arm the synchrocheck relay and monitor the closure.

Failure of the synchrocheck relay may be the result of various issues, and the WAMS visualisation allows the operator to interpret which of the various causes may be responsible and establish a course of action:

- Failure to close due to frequency difference
    - Frequency difference is too high so that relay close conditions are not met → adjust anchor governor setpoint
    - Frequency difference is very small and angles do not reach alignment → retry until success, as angles will eventually align
    - Island frequency is oscillating due to governor control instability
        - → if more than one unit is providing proportional frequency response, switch all but one governor control modes to constant power
        - → growing the island by increasing load and generation will tend to improve stability compared with a lightly loaded island
        - → disable governor frequency control while resynchronising; reinstating if still not successful
- Failure to close due to voltage difference → adjust voltage setpoints to align voltages across the boundary
- Reopening after initial closing due to large power swing
    - Frequency difference too large leading to power swing as the island inertia is accelerated or decelerated on closure → reduce frequency difference and retry, and reduce synchrocheck frequency difference setting (if possible)
    - Angle difference too large → reduce synchrocheck angle setting (if possible) or manually manage frequency and angle difference

Resynchronisation is considered successful once the angles and frequency have been locked in alignment for more than a pre-set time period, e.g. 15-30s. A signal indicating a stable interconnected state will be raised and sent to the ADMS.

5.2.5 Stage 6 Termination

The DRZC will automatically disable the Fast and Slow Balancing functions as soon the interconnected state signal is raised.

Once successful resynchronisation has been achieved and the interconnected state signal has been received by the ADMS, the operator initiates the following processes through pre-defined switching sequences and automation in the ADMS:

1. Network switching sequence to restore to normal operating topology
2. Anchor generator governor restored to normal constant power mode of operation
3. Protection restoration to grid-connected settings groups

It may be beneficial to be able to reinstate island operation by reinstating fast and slow balancing, anchor generation frequency control and reverting protection to the island settings group.

5.3 Fast Balancing

The island experiences large frequency excursions in various planned and unplanned situations including:

- Load pickup
- Unplanned trip of generation or load
- Windfarm high windspeed cutout

Balancing action must be taken within a defined timeframe depending on the island inertia and the allowable RoCoF in order to stabilise frequency. The balancing action must bring the island power balance sufficiently close such that frequency regulation (mainly from the anchor generator) should keep the frequency nadir or zenith within pre-defined boundaries. Balancing action is done by switching the load bank.

By default, the anchor generator and the load bank will operate within a pre-defined band with sufficient margin to accommodate an unplanned loss of generation or load. Fast and slow balancing and frequency regulation will normally operate in parallel as follows:

- Fast balancing ensures that RoCoF is maintained within limits
- Slow balancing manages the margins available for control
- Local anchor generator frequency control (governor droop) ensures that frequency level does not exceed limits.

A monitoring process (see Section 5.8.6) will be available to determine the level of load or generation loss that can be sustained with the present level of fast balancing response and proportional regulation. The operators will be informed of the running pickup and dropoff capability and can compare this with the present level of tripping risks and planned load pickup. There may be cases where the operator temporarily pauses slow balancing and maximises the load bank power to pick up a larger load.

5.3.1 Role of BESS

Both the load bank and BESS are termed "flexible demand" that can be used by the fast balancing function to manage the anchor generation frequency. The resources can be used interchangeably and in parallel for fast balancing where a combined response would increase the BLPU capability.

The anchor generation will manage the DRZ frequency in speed-setting made and the BESS can be used for fast balancing via DRZC setpoint control. BESS would not be set in a frequency sensitive mode of control.

BESS would be subject to the same testing outlined in Section 5.3.7 to ensure the response was adequate to avoid anchor generation tripping within the allowed time budget. The resource manager described in Section 5.6 would manage the aggregated response of the PBC (flexible demand) to ensure there was enough combined response to manage any unplanned events.

Slow balancing would manage the anchor and BESS regulating margins to ensure (1) the anchor generation can manage the DRZ frequency and (2) BESS response is available in case of unplanned load tripping.

If both BESS and load bank were available in the same DRZ this would increase the BLPU capability. Both BESS and the load bank constraints could be managed by SBC to ensure greater MW response is available to fast balancing.

It is understood that BESS has STATCOM like capabilities. Voltage management by the DRZC is currently out of scope but use cases related voltage control include:

- **Increasing the reactive load pickup capability through BESS voltage control**: GE proposed a Q load probing capability to determine the V/Q response after each energisation step to determine the reactive load pickup capability. It is assumed BESS voltage control acts in <100ms to help stabilise voltage and allow increased reactive loading
- The island will be operating at very low system strength with most of the contribution coming from the anchor generation. BESS can help support system strength at near-nominal voltage and may facilitate more stable connection of DER to the DRZ

5.3.2 Operational Frequency and RoCoF Limits

<u>RoCoF Limit</u>

Operational limits are specified in order to define the volume and speed of response of frequency balancing and regulation capability, and the amount of load that can be picked up. It is also important for security against unplanned events. The limits are derived from the ENA G99 Engineering Recommendations combined with further margins for stable operation.

ENA Engineering Recommendation G99 [3] lists the protection requirements in Table 4 for distributed generation Types A / B / C / D, covering power generation modules from 800W up to >50MW generation connected at 132kV and above. Since all DER should withstand the G99 conditions, the values in the recommendation are a generalised requirement. There may be islands where maintaining these levels is impractical and protection can be set to wider limits during the islanded state (though there must be frequency protection), but in these cases it is necessary to consider the wider effects on distributed generation stability of operating outside the G99 limits. For example, the capability of Phase Locked Loops (PLL) of smaller renewable generation may be limited to certain frequency and RoCoF limits, and thermal generation may have physical turbine limits.

From Table 4, it may be noted that Loss of Mains RoCoF limits are 1Hz/s with a time delay of 0.5s. There are further latencies involved in the windowing for deriving frequency and RoCoF. There are currently no standards defining RoCoF derivation, but a recent European metrology project [5] has proposed to standardise 500ms window length (250ms latency) for RoCoF applied to Loss of Mains protection. This implies that the time available to resolve a RoCoF violation of >1Hz/s is around 0.75s before there is a risk of Loss of Mains triggering compounds a disturbance. However, the RoCoF window latency will also introduce a latency of up to 250ms for the measured RoCoF to follow the physical RoCoF. Thus, the **target time to reduce RoCoF below 1Hz/s is 0.5s** to avoid a potential cascade of Loss of Mains triggers.

It would be possible to disable loss of mains protection during islanding operation, however this is not advised. Disabling LoM protection would leave the DER generators exposed to isolated operation and over/underspeed. It would add to the complexity of the transition between island and grid-connected operation. Furthermore, operating within the G99 requirements ensures that equipment runs within boundaries for which it has been tested. The DER response to wider frequency and RoCoF excursions outside the connection requirements with protection disabled may be untested in live environments with uncertain outcomes.

Protection Function		
	Trip Setting	Time Delay Setting
U/V Stage 1	0.85 pu$^{\$}$	3.0 s
U/V Stage 2	0.6 pu$^{\$}$	2.0 s
O/V	1.1 pu$^{\$}$	0.5 s
U/F	48 Hz	0.5 s
O/F	52 Hz$^{\#}$	1.0 s
LoM (RoCoF)$^{¥}$	1.0 Hzs^{-1}	0.5 s$^{\propto}$

Table 4 G99 Settings for DER Long-Term Parallel Operation (reproduced from ENA G99 [3])

To ensure that operation remains within the protection limits and withstand capability of the DERs, a 20% margin is proposed as the control target in terms of level and time delay. The boundary of acceptable operation is therefore within the protection boundaries.

The recommended operational ROCOF limit is therefore +/- 0.8Hz/s.

Frequency Limits

It is assumed that Under Frequency Load Shedding (UFLS) and Over Frequency Generation Shedding (OFGS) can be disabled or set to wide limits for the island operation period, so the relevant limits are also related to DER G99 recommendations. As listed in Table 4, under- and over-frequency are 48Hz (0.5s delay) and 52Hz (1s delay) respectively.

A 20% margin applied to the frequency level would allow 50Hz +/- 1.6Hz. Applying a 20% limit to the time delay requires that violations are resolved within 0.4s for low frequency and 0.8s for high frequency.

However, the starting point of frequency is variable and not necessarily at 50Hz, and is assumed to be within a band of +/-0.2Hz for normal operation of the island. This means that an excursion of frequency should be less than 1.4Hz (i.e. 1.6Hz less 0.2Hz normal frequency variability). In the physical system, the frequency during a disturbance should be kept within 48.4-51.6Hz, but in simulations where pre-event frequency is exactly 50Hz, a further 0.2Hz margin should be applied, thus arriving at the limits of 48.6-51.4Hz in Table 5.

	Physical Limit	Simulation Limit	Time delay
Under frequency	48.4Hz	48.6Hz	0.4s
Over frequency	51.6Hz	51.4Hz	0.8s
ROCOF	+/- 0.8Hz/s	+/- 0.8Hz/s	0.4s

Table 5 Frequency and RoCoF Limits for Physical Operation and for Simulation-based Testing

5.3.3 Fast Balancing Process

The high-level fast balancing process is shown in Figure 4. The process consists of:

- **Event Detection**: RoCoF-based threshold (based on Table 5) to detect a fast frequency excursion that requires fast balancing action
- **Imbalance calculation**: Based on H_{ANCHOR}* RoCoF to determine amount of power imbalance in the island
- **Trigger and dispatch**: Digital trigger and MW setpoint sent to load bank (or BESS if available)
- **Growing balancing value**: The power imbalance calculation will increase up to the maximum RoCoF value. The load bank MW setpoint is continuously updated with this value to ensure the power loss is adequately balanced and frequency stability maintained (see Section 5.3.6.5)
- **Frequency and RoCoF within limits**: The operator will have access to WAMS UIs to monitor the frequency and RoCoF performance

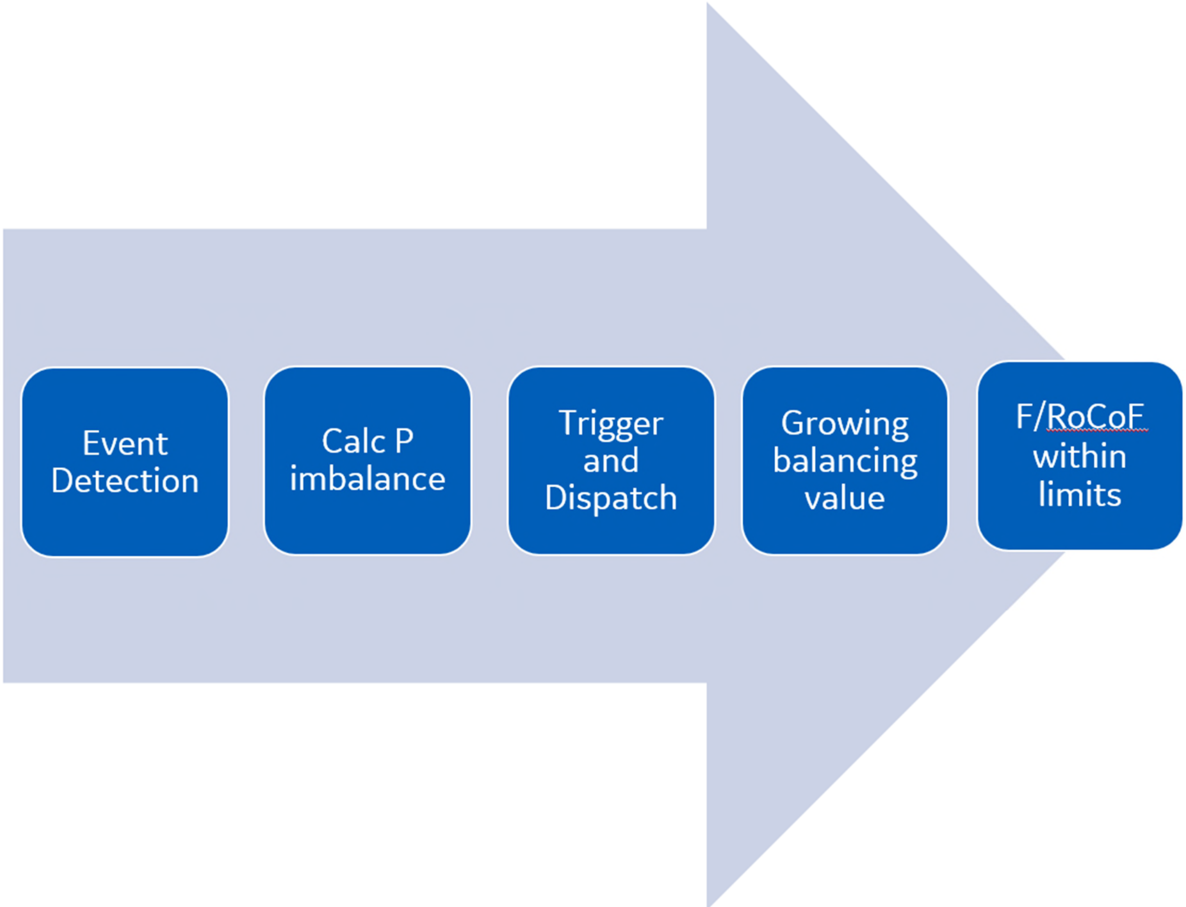


Figure 4 Fast balancing process

5.3.4 Inputs, Outputs and Parameters

Inputs	Frequency from Stevens Croft anchor generator and Chapelcross Power from load bank Power from any other loads as measured via the primary circuits Power from other resource that could conceivably be used for fast balancing i.e. BESS
Outputs	Trigger to signal an event has been detected Target balancing power MW (updated based on measured RoCoF)
Parameters	Acceptable RoCoF limits Acceptable frequency limits Event detection configuration parameters Inertia of anchor generator RoCoF configuration parameters (e.g. window length, % valid samples)
Algorithm(s)	Event detection to trigger action at earliest reliable time. RoCoF either using event detection (with growing window) or separate process over given window length using valid samples available. Inertia (use anchor generator H parameter) Power imbalance MW calculated by H.RoCoF. Note that this is only applicable to the islanded scenario, not grid connected
Pre-requisites	Inertia H parameter Islanding vs grid connected mode detection Acceptable frequency and RoCoF envelope must be defined. Regulation speed of the anchor generator and any other frequency regulators should be known Maximum sustainable load or generation loss should be defined Details of how load bank is deployed e.g. setpoint change, load block trigger, etc.

Table 6 Fast balancing inputs, outputs and parameters

5.3.5 Example Operation of Fast Balancing

When the island experiences an imbalance of power, the imbalance is proportional to RoCoF, and related by the inertia of the island. At the point of a load pickup, RoCoF immediately drops rapidly to a negative value. The Fast Balancing scheme detects the disturbance and initiates a response from the Primary Balancing Control resources, which in the case of Chapelcross is the load bank.

If there is sufficient resource available, the Fast Balancing scheme will target zero RoCoF by compensating the estimated loss of power with a controlled reduction of load at the load bank. In many cases, there will not be enough resource available to fully balance the load pickup, so the Fast Balancing approach would deploy the available resource with the effect of reducing RoCoF so that it returns within +/- 0.8Hz/s. This avoids DER tripping on loss of mains and also increases the time available for proportional regulation of frequency to act.

The example in Figure 5 illustrates qualitatively how frequency is influenced by fast balancing. Without fast balancing, the event produces an initial frequency excursion that violates the RoCoF limit and the lower frequency threshold.

An event occurs at T_0 resulting in a negative power imbalance – this could be a load pickup or an unplanned DER trip. The Fast Balancing algorithm detects a distinct change in frequency and calculates RoCoF using a growing window starting from T_0. A trigger is raised between T_0 and T_1 and takes effect at T_1 illustrated by the red line diverging from blue in Figure 5. This increases RoCoF above -0.8Hz/s within the 0.75s required to avoid loss of mains protection triggers. Slow balancing is disabled to allow the load bank to move outside the Trim_level thresholds without the response being counteracted by slow balancing control.

Proportional regulation of frequency starts once frequency has increased outside the deadband. Since it is proportional to frequency, it does not immediately respond in proportion to the scale of the event. However, it will increase in value as time passes, and reaches the maximum value around T_2. As long as frequency is outside the target range for no more than 0.4s, the control has achieved its goal.

When the fast balancing control is released, the load bank control should remain at the load level that was last deployed. The load bank level is only changed again once slow balancing is re-enabled and Secondary Balancing Control is deployed in order to restore a frequency balancing margin.

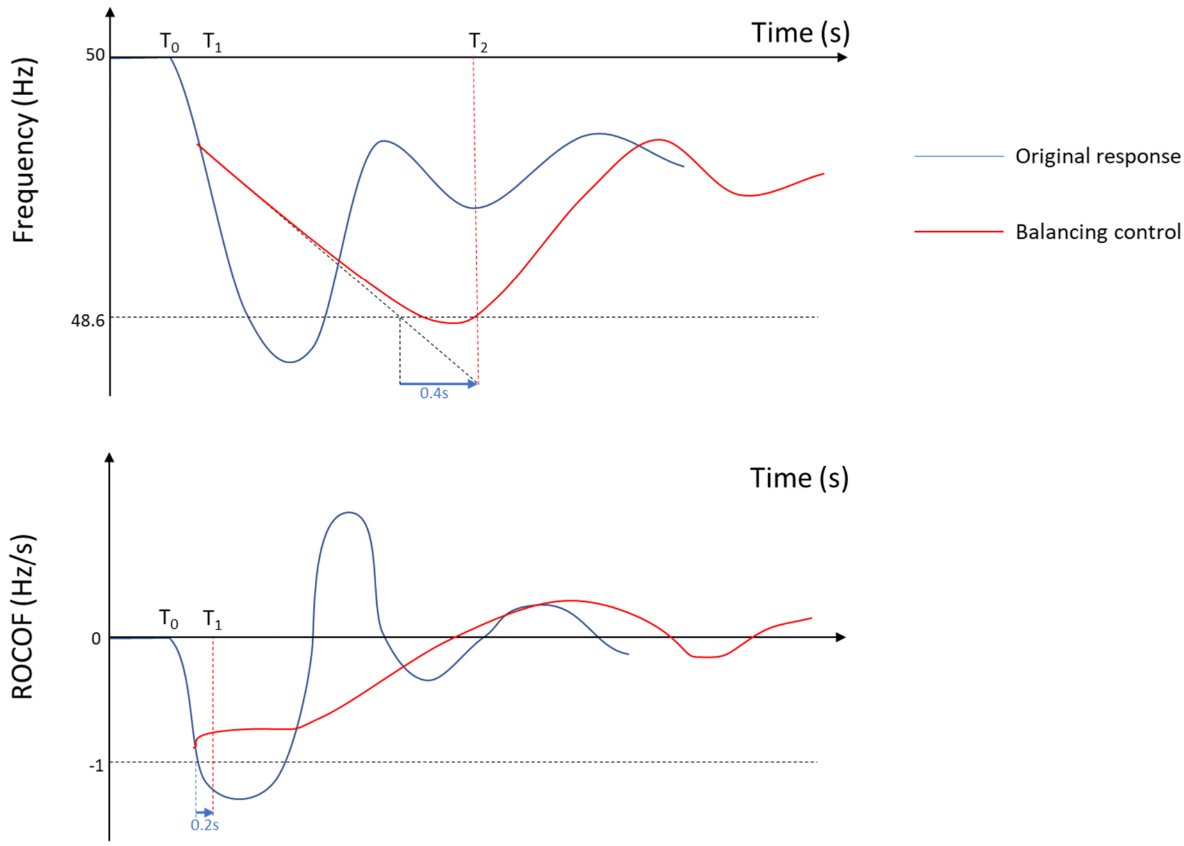


Figure 5 Qualitative illustration of the effect of Fast Balancing on frequency and RoCoF

5.3.6 Algorithm Description

The algorithm detects events using anchor generation RoCoF and calculates the power imbalance based on RoCoF and the inertia of the anchor generator. The algorithm sends the required balancing power to the load bank where the setpoint change is implemented.

5.3.6.1 Inputs

A frequency measurement from a P-class PMU that is compliant with IEEE C37.118 2011 (rev 2014) standards with a 50 FPS update rate.

5.3.6.2 Outputs

Trigger: A digital indicating the detection of an event.

Balancing Power: The required power to balance the system in MW

5.3.6.3 Settings

The fast balancing Application Function Block (AFB) has the following configurable settings outlined in Table 7. This gives the description of each setting as well as the value used for the Chapelcross test cases.

Setting Name	Value used in testing	Description
detectionMovingWindow	0.5 s	Window length for ROCOF
safetyTimeDelayDetection	0 s	Time delay to avoid triggers due to spurious measurements
frequencyChangeThreshold	10%	If frequency changes by more than this setting, detection is blocked.
overFrequencyThreshold	5%	Threshold for triggering based on frequency deviation if ROCOF is within limits. This is used for slow ROCOF events.
underFrequencyThreshold	3%	Threshold for triggering based on frequency deviation if ROCOF is within limits. This is used for slow ROCOF events.
RoCoFThresholdOF	0.5 Hz/s	Over-Frequency ROCOF Threshold.
RoCoFThresholdUF	0.5 Hz/s	Under-Frequency ROCOF Threshold.
dfForOverFrequency	0.05 Hz	The difference in frequency that must be observed for the over-frequency event algorithm to be initiated.
dfForUnderFrequency	0.05 Hz	The difference in frequency that must be observed for the under-frequency event algorithm to be initiated.
Inertia	200 MVAs	Inertia is used to calculate the balancing power from ROCOF
resetEventTime	2 s	The time to clear the event, if ROCOF remains within limits for this amount of time.

Table 7 Fast Balancing AFB Settings

5.3.6.4 Event Detection

There are three checks implemented for detecting an event. These include (1) measuring the RoCoF and comparing it with defined thresholds to capture events with a large power imbalance, (2) measuring frequency differences within a specified time period for faster event detection and (3) absolute frequency deviation for detection of events with a low RoCoF that lead to large frequency deviations.

This RoCoF-based method is shown in Figure 6. The algorithm uses a moving window with a maximum size defined by the setting "detection moving window". The algorithms are designed to detect events with rate of change of frequency greater than the setting "RoCoF threshold" (there are separate thresholds for over and under-frequency RoCoF).

The algorithm also uses the settings "Δf for under frequency" (ΔF_{UF}) and "Δf for over frequency" (ΔF_{OF}). If the frequency deviates by more than Δf within time Δt, this indicates a RoCoF of $\frac{\Delta f}{\Delta t}$. The maximum time to trigger, is therefore defined by Δf and the RoCoF_threshold, $\Delta t_{max} = \frac{\Delta f}{ROCOF\_Threshold}$. For the test cases in this report, Δf=0.05Hz, and RoCoF_threshold=0.5Hz/s which gives a maximum triggering time of 100 ms. If the time corresponding to this frequency difference equal to ΔF_{OF} or ΔF_{UF} is less than the maximum trigger time (100ms), event detection algorithm will be triggered.

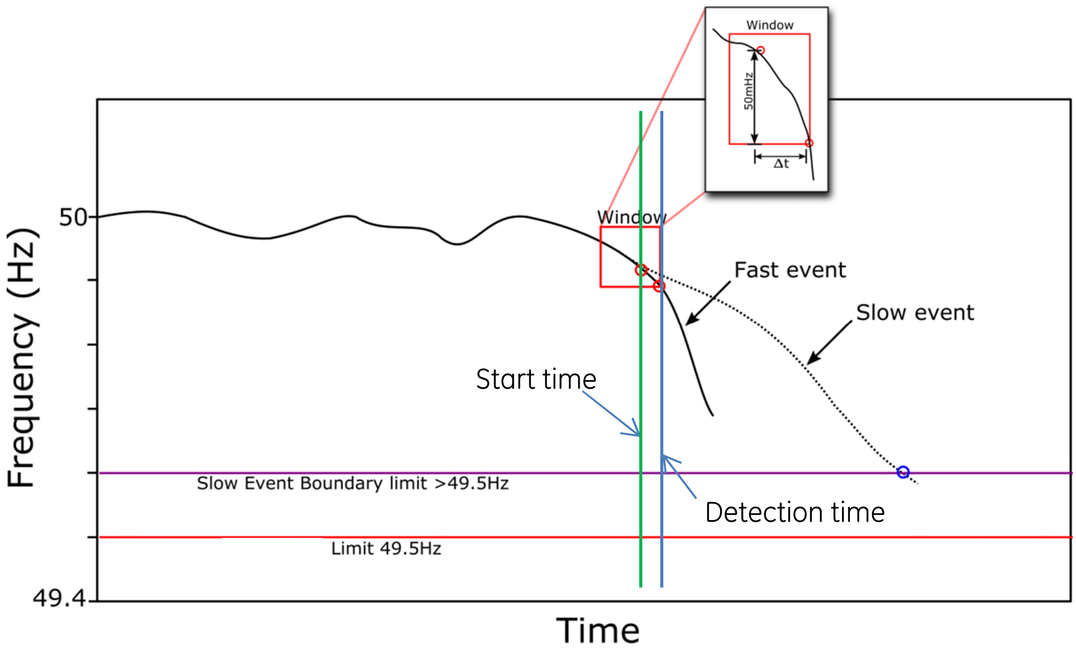


Figure 6: Event Detection method based on frequency and RoCoF

The advantage of this method is that it does not need to wait for a predefined time or window to find a RoCoF which can add a delay, but instead will use frequency and calculate the time difference. This provides faster detection for high RoCoF events, however slow events may not be captured, i.e. a frequency change less than 0.5 Hz/s (the RoCoF threshold is defined by the setting "RoCoF Threshold for Over/Under-Frequency").

If the frequency change is slow, it may not be detected by RoCoF. Therefore, an additional set of bounds is added that is slightly less than the protection limit thresholds. If a slow frequency event occurs, it is detected once it crosses a boundary value such as 48.5Hz/52.5Hz (3% and 5% difference) combined with a hysteresis value (the boundary frequency values are set by the settings "over/under Frequency Threshold" and the hysteresis value is equal to the "Safety Time for Delay Detection" value). The hysteresis will prevent triggering on a single sample moving outside the boundary.

5.3.6.4.1 RoCoF Calculation

The frequency values are initially stored in a buffer. The whole of the buffer is then checked for cases where the difference between any measurement and the latest frequency measurement is larger than the "Delta Frequency Setting for Over/Under-Frequency" (while ensuring that the quality of the compared frequencies is valid). This defines whether the occurrence of an event is possible, as per the description in the previous section. The growing gradient calculation is performed on the buffer values.

The steps of the frequency growing window calculation are shown in Figure 7. The initial gradient is calculated in Figure 7 (a) using the start-time and the detection time as the initial points which is used to trigger detection. For the next stages of response allocation, a RoCoF value will be required to characterise the MW response of the load bank. Therefore, a window is then created in Figure 7 (b) and the best fit method is applied to give a better representation of the RoCoF compared with taking two samples. If this window size is less than the maximum size, the window is allowed to grow in size by taking more samples providing a larger sample set by which to calculate the best fit and refine the gradient value. The start time remains the same, however, for each new sample; the window size is increased to accommodate this new value as shown in Figure 7 (c). Once the maximum window size has been achieved, the window will shift across, so for every new measurement point, the first point in the window will also move accordingly as in Figure 7 (d). This method ensures that as much data as possible is available for the RoCoF calculation hence providing the best estimates for frequency gradient.

Linear regression is used to calculate the best-fit frequency gradient using a number of frequency samples based on the window size at each execution.

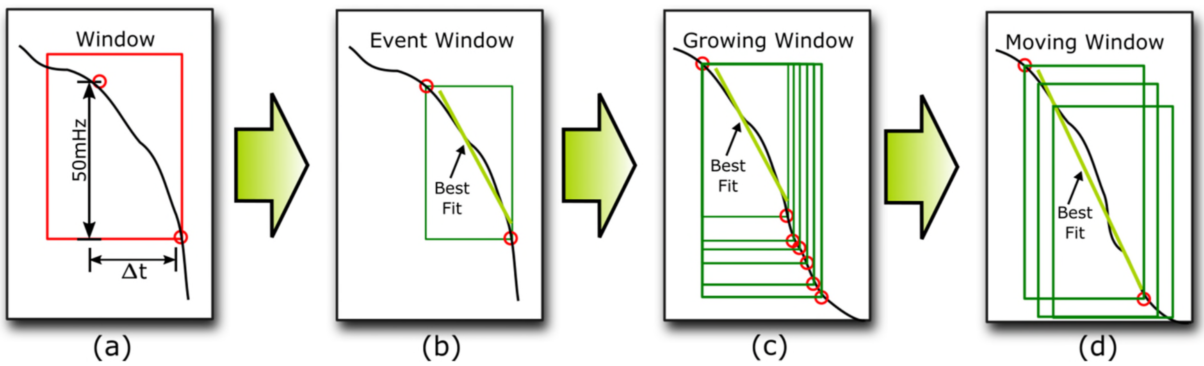


Figure 7 Moving Window for gradient calculation

The output is then compared with the "ROCOF Threshold for Over/Under-Frequency" values. Again, if the RoCoF exceeds one of these thresholds for longer than the "Safety Time for Delay Detection" value, the overall output is set and an event is detected.

5.3.6.5 Calculating the Balancing Power

The balancing power is calculated using the anchor generator inertia and the event RoCoF. In the tests described here the generator inertia is 200 MVAs. Balancing power is calculated as follows:

$$BalancingPower = \frac{2H * ROCOF}{NominalFrequency}$$

It is expected that RoCoF will increase as the event enters the analysis window. It is also expected that RoCoF will reduce during the event due to the fast balancing and anchor generator responses. The calculated balancing power is only allowed to increase with RoCoF (with the same sign) and will stay at that level so that the response is not reduced as soon as RoCoF starts reducing. The load bank / battery will remain at the output corresponding to the largest RoCoF recorded during the event, until the slow balancing AFB changes the load bank set point to prepare it for the next event.

This is illustrated in Figure 8 where the actual imbalance is compared against the balancing power of the load bank. There is a delay in changing the load bank setpoint based on the event detection trigger and communications latency etc. The MW response will increase based on the measured RoCoF and will stabilise at the maximum RoCoF. The load bank response should deliver a MW response close to the actual loss. Statistics can be produced showing how closely the response met the imbalance. The example on Figure 8 shows a ±20% requirement within 1sec of the event.

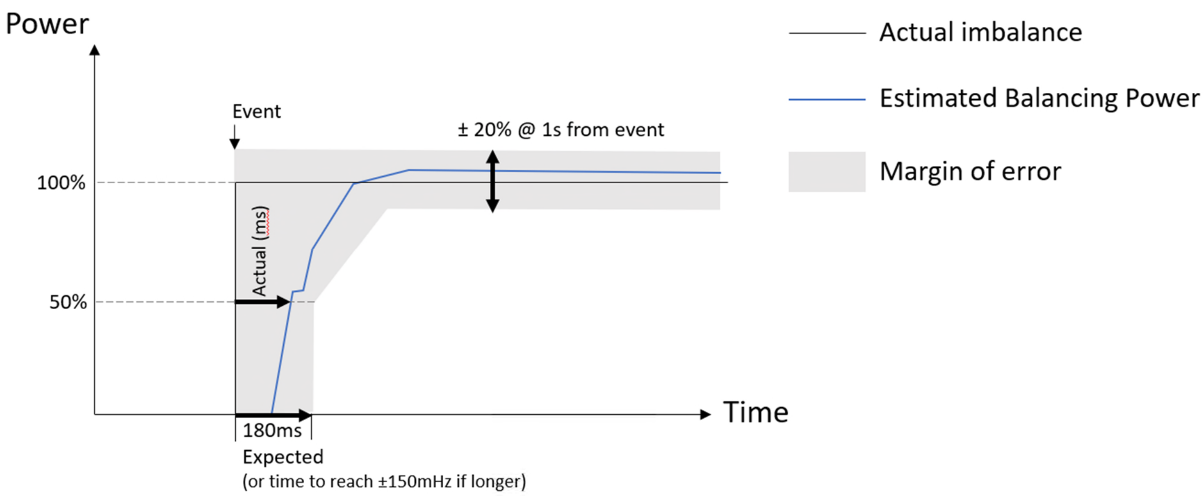


Figure 8 Load bank power response based on measured RoCoF during an event (continuous response provided up to maximum RoCoF). Response should settle within some defined margin of actual imbalance

5.3.6.6 Resetting the event

When an event is detected, the fast balancing AFB will raise a trigger to high and will remain high until the event has ended. This is important as the balancing power needs to be reset so that it can be re-calculated for new events.

The condition for resetting the event is based on absolute RoCoF being less than the RoCoF thresholds for a settable period. The tests carried out in this report use a setting of 2 seconds.

5.3.7 Testing

The algorithm was tested using 6 simulation cases produced by TNEI based on restoration options outlined in [6]. These chosen test cases were the constant impedance load tests for Option 1, Option 2, Option 3, Option 4a, Option 4b, and Option5. These tests were open loop, i.e., the simulated signals are passed to the algorithm, but the output of the algorithm does not impact the simulated signals.

5.3.7.1 Test Criteria

In closed loop tests, it would be advisable to base test criteria on RoCoF and frequency staying within certain limits. However, due to the limitations of the open loop testing we cannot calculate the combined impact of the anchor generator and the fast response on the island frequency. As a result, we have chosen the following criteria for the open loop testing of the fast balancing AFB:

- For events with a RoCoF greater than 0.6Hz/s, a response of at least 50% of the power imbalance within the trigger time requirement described below
- Expected trigger time is the greater of 180 ms or the time for frequency deviation to reach 150 mHz from the start of the event. This means that for events with more than 6.67 MW actual imbalance the expected trigger time is 180 ms. The 180 ms requirement was calculated based on the requirement of total elapsed time to respond being less than 500 ms, as described in Section 5.3.2 and shown in Figure 9.
- The target balancing power output should be within 20% of the initial power imbalance 1 second after the start of the event.
- Must not trigger for events below 0.4 Hz/s which is equivalent to 3.2 MW of imbalance
- If RoCoF is between 0.4 Hz/s and 0.6 Hz/s, both triggering and not triggering are acceptable responses. There is no requirement on the trigger time. However, the balancing power should be less than 5 MW

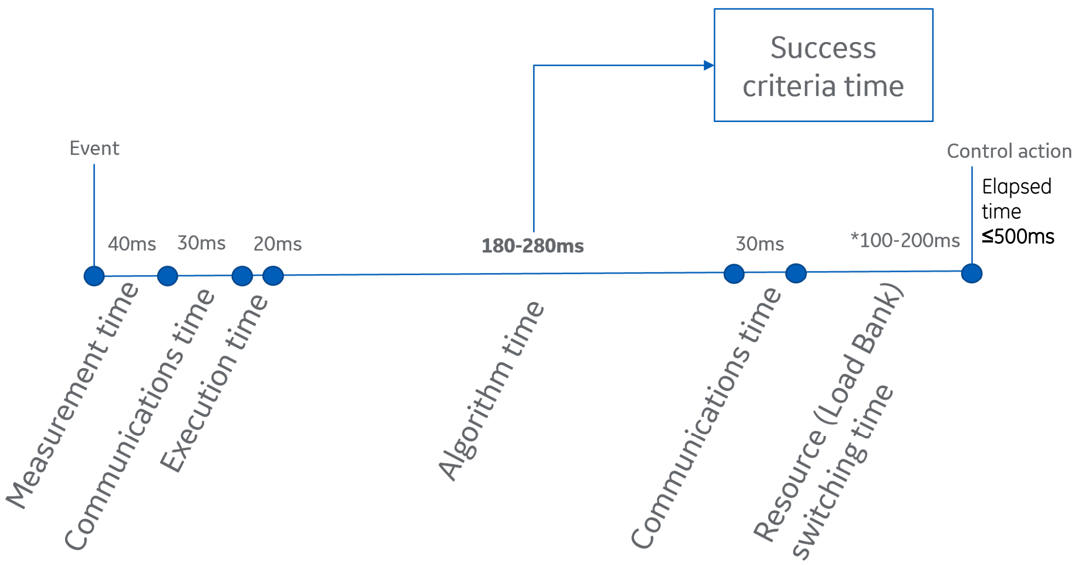


Figure 9 Time budget from triggering event to control action and algorithm response time target

5.3.7.2 Test results

Each test had a simulation period of 600 seconds with multiple events contained in each test. Figure 10 to Figure 12 show an example from the first event in the Option 1 test case. The switching occurs at 140 seconds with a power imbalance of 12 MW (load pickup). The event is detected at 140.06 seconds, but the balancing power reaches 50% of the imbalance at 140.08s, 80ms from the start of the event. This is well within the 180ms requirement. Similar charts for all events from all test cases are included in Section 8 (Fast Balancing test results) appendices.

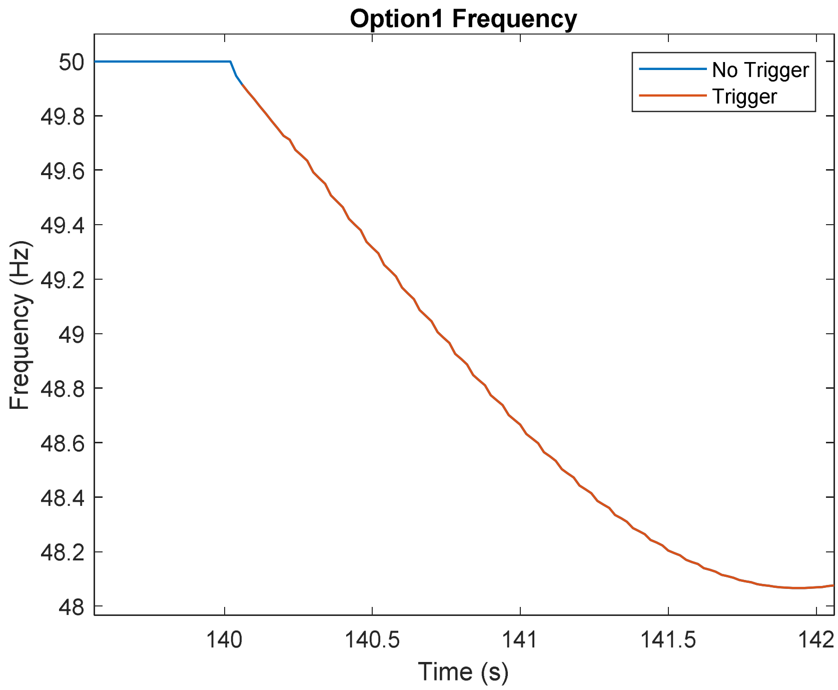


Figure 10 Frequency measurement for a load pick-up event (12MW block load)

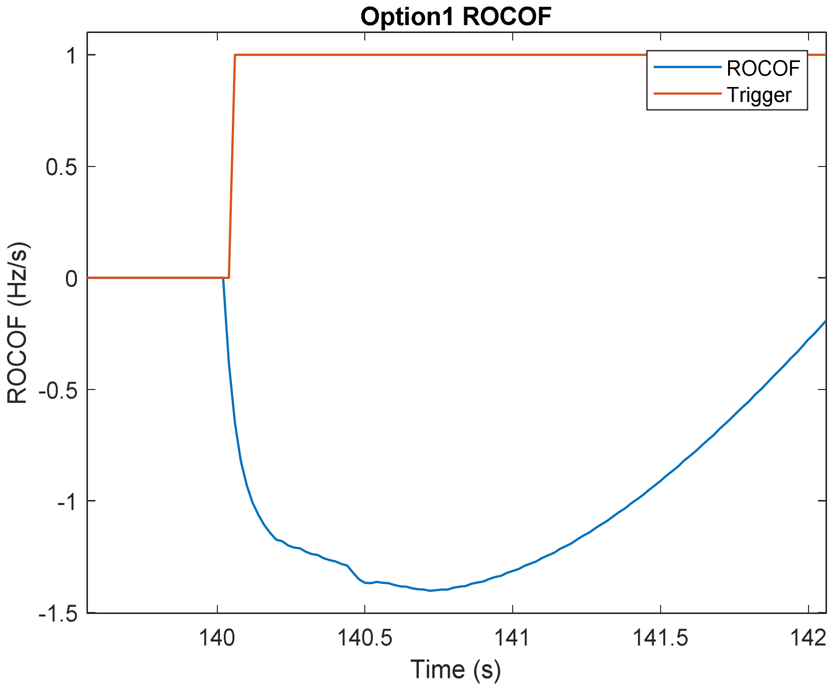


Figure 11 RoCoF measurement for a load pick-up event (12MW block load)

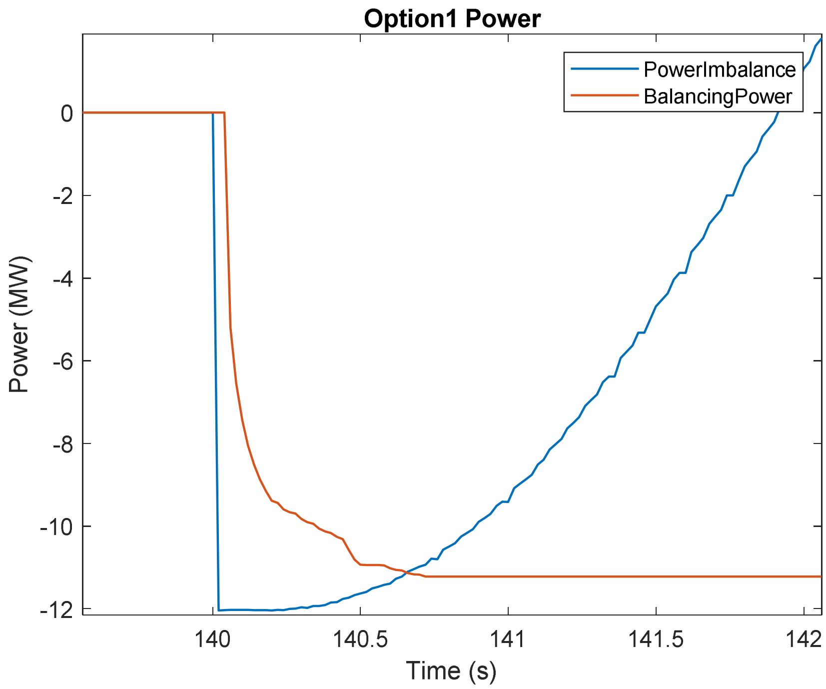


Figure 12 Power imbalance in island and balancing power requested by Fast Balancing algorithm

Table 8 below gives the time for the response to reach 50% of the imbalance for cases with RoCoF greater than 0.6 Hz/s which is equivalent to a ΔP of 4.8 MW. In all cases the response was triggered within 60-80ms, well below the target of 180ms. It should be noted that these results did not include any safety delay/hysteresis which would be required when using real measurements to avoid spurious triggering on spurious measurements.

Event Time (s)		Option 1	Option 2	Option 3	Option 4a	Option 4b	Option 5
140	ΔP (MW)	12	12	12	12	12	10.6
	Target P (MW)	11.2	11.6	11.2	11.3	11.3	10.1
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	80	80	80	80	80	80
160	ΔP (MW)	11.2	11.2	11.3	11.3	11.3	11.3
	Target P (MW)	10.7	10.3	10.3	10.4	10.4	10.1
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	80	80	80	80	80	80
170	ΔP (MW)	7.6	7.5	7.6	7.7	7.7	9
	Target P (MW)	6.7	6.7	6.7	6.8	6.8	8.2
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	60	60	60	60	60	60
210	ΔP (MW)	8.3	8.3	8.3	8.2	8.3	10.5
	Target P (MW)	7.6	7.5	7.2	7.2	7.5	9.5
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	60	60	60	60	60	80
220	ΔP (MW)						6.4
	Target P (MW)						5.5
	Expected (ms)						200
	Actual (ms)						80
250	ΔP (MW)	11.9	11.9	11.9	11.9	11.9	13.9
	Target P (MW)	11.4	11.5	11.5	11.7	11.5	13.8
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	80	80	80	80	80	80
330	ΔP (MW)	10.8	10.8	10.5	10.6	10.6	11.4
	Target P (MW)	11.1	11	11	11.1	11.1	11.5
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	60	60	60	60	60	80
400	ΔP (MW)	10.2	10.2	9.8	9.7	9.8	11.6
	Target P (MW)	11	10.6	10.6	10.8	10.5	11.9
	Expected (ms)	180	180	180	180	180	180
	Actual (ms)	60	60	60	60	60	80
420	ΔP (MW)						7.5
	Target P (MW)						6.9
	Expected (ms)						280
	Actual (ms)						100

Table 8 Summary of fast balancing test results

5.4 Slow Balancing

The goal of Slow Balancing of the island is to maintain the Proportional Regulation (anchor generation) and Primary Balancing Control (load bank) within the operating regions in which they maintain reserve for changes in the island power balance, including slow drift of operating state and following actions of the Fast Balancing function.

The "Slow Balancing" task performed by DRZC will dispatch controls direct to the participating DER and breakers. Slow balancing runs in parallel with Fast Balancing that is also controlled directly from the DRZC. Interaction between DRZC slow balancing and the DER includes:

- DER operating points and Power Available sent from windfarms to the DRZC
- DRZC will send dispatch changes and trip signals to DER plant and load breakers

Description	Slow balancing applies generation constraints in order to keep a regulating margin available at the anchor generator and to ensure that there is capacity for positive and negative load steps at the load bank. There may also be a requirement for load relief if the anchor generator is running close to the maximum output. The anchor generator should normally operate within a given band, with a margin to its maximum and minimum regulating points. If the generator exceeds these limits, action should be taken to constrain generation or disconnect load in order to move the generator closer to the middle of the regulating range. If this can be done by changing the load bank operation and moving it closer to the midpoint (or the preferred operating point), then this is given priority. Otherwise, resources such as windfarms shall be sent revised setpoints (< available power) or loads rejected (as a last resort). The action is not time-critical since frequency is continuously regulated provided sufficient regulating margin is allowed.
Inputs	Anchor generator power Load bank power Windfarm power Selected loading (power) in Chapelcross primaries
Outputs	Load bank power Windfarm power setpoint Selected load trips
Pre-requisites	Available power signal for windfarms

	Windfarm response time
Parameters	Anchor generator target operating zone Load bank target operating zone Max/min limits of renewable generation
Algorithm(s)	Thresholding with deadband and hysteresis Ordered action list Response validation Iteration of control process

Table 9 Fast Balancing Inputs, Outputs & Parameters

5.4.1 Slow Balancing Procedure

Slow island balancing is achieved with the following co-ordinated methods:

1. **Proportional regulation (PR):** governor droop or speed control carried out by the anchor generator. This is continuous control, active as long as the generator is within its normal operating power zone. PR has no direct input from the DRZC.
2. **Primary balancing control (PBC):** load bank and/or battery control that is achieved by setpoint control with rapid response. Primary balancing does not affect customer supply.
3. **Secondary balancing control (SBC):** Setpoint or tripping control applied when proportional regulation and primary regulation have insufficient reserve margin to accommodate a possible change in the island power balance. A subset of resources (SBC1) acts on DER generation and does not affect customer supply, while SBC2 resources involve load tripping. SBC1 is used in preference to SBC2 wherever possible.

Slow island balancing is used to dispatch primary and secondary balancing. It has no direct control on the proportional regulation, but primary and secondary changes will affect frequency and therefore will influence the power of the anchor generator.

The goal of Slow Balancing of the island is to maintain the Proportional Regulation and Primary Balancing Control within the operating regions in which they maintain reserve for changes in the island power balance, including slow drift of operating state and following actions of the Fast Balancing method.

To achieve this without direct control of PR, the slow island balancing will act as follows, with reference to Figure 13:

1. Define preset Trim levels for PR and PBC, defining the margin that should be maintained (Trim Level) and the target range to be achieved to complete a trimming action (Trim Margin).
2. Raise **Trimming_in_progress** when either PR or PBC reaches the preset Trim Level (+ or -)
3. Determine if the combined PR & PBC levels are within the total PR & PBC Trim Margins, i.e. $B_1+B_2 < PR+PBC < C_1+C_2$
    a. If YES define and adjust value of adjust PBC by the larger of
        i. the value that moves PR within its Trim Margins
        ii. the value that moves PBC within its Trim Margins

   b. If NO use SBC as described in set 4 below to achieve total PR & PBC levels within the Trim Margins
4. If SBC response needed (step 3.b.)
   a. Determine maximum and minimum response value of SBC to move PR+PBC within $\{B_1+B_2 < PR+PBC < C_1+C_2\}$. May be positive or negative.
   b. Select an SBC resource, or a stacked set of resources that achieves $\{B_1+B_2 < PR+PBC < C_1+C_2\}$ with minimal dispatch, subject to the size of blocks of available SBC reserve and margin of error for confidence to achieve the result.
   c. Dispatch SBC resources according to
      i. SBC1 Resources prioritized e.g. DER Raise/Lower with no customer loss of supply
      ii. SBC2 Resources e.g. customer load shed used if SBC1 insufficient
      iii. Where possible using step sizes smaller than steps that may trigger a Fast Balancing response (may not always be possible)
   d. Repeat step 3.
5. If no further SBC response needed (case 3.a), confirm that PR and PBC are both within their respective Trim Margin levels.
   a. If YES lower Trimming_in_progress
   b. If NO repeat from 3
6. Trimming_in_Progress should not remain raised continuously. Although it does not create a problem for other actions (PR and Fast Balancing are not interrupted), the state would indicate that there is a problem with controlling the devices or that there is insufficient resource available as SBC. If Trimming_in_Progress remains raised for more than a pre-defined time period or number of Slow Balancing cycles, a warning is raised with the operators for manual resolution.

Timing is important. Slow balancing is carried out on a regular cycle with sufficient time for the anchor generator governor to settle to a new steady-state level. This would typically be 10-15s, but would be a settable parameter. After a fast balancing action, the slow balancing is disabled for at least two cycle periods of slow balancing.

Power signals are filtered with a lowpass filter before driving the slow balancing process. This removes electromechanical dynamics, avoiding spurious responses to power swings and oscillations. The filter is intended to attenuate components above 0.5Hz; typical local mode oscillations of generators of this size will tend to be above 1Hz.

A fast balancing response may be triggered by a step change of power balance caused by SBC2 load shedding action. A load trip will affect the PR+PBC level and may require a rebalancing between the load bank and generator. The sequence below is possible in the case of an SBC2 load disconnection:

1. SBC initiated as anchor generation (PR) rises above D_1 (Trim Level +) and/or negative power of load bank (PBC) rises above D_2 (Trim Level +) such that PR+PBC is above C_1+C_2 Trim Margin+
2. Large step change applied as SBC action (e.g. SBC2 load trip)
3. Frequency rises and large positive ROCOF detected
4. Fast balancing is triggered to increase load at load bank. Frequency gradient is reduced (to target zero-RoCoF if possible) as in a normal fast balancing operation
5. Anchor generator responds to high frequency by reducing generation (PR) bringing frequency into the normal operating zone within Trim_Margin limits

6. Slow Balancing will instruct a load bank change if necessary so that PR and PBC both achieve the appropriate margins.

Similarly, if there is a large load pickup, there is a large negative RoCoF that triggers fast balancing to decrease the load at the load bank. In unusual circumstances, this may result in a Slow Balancing SBC2 load trip response, however the operational procedure and tools in Section 5.8.6 is intended to avoid this. Load pickup is not blocked during a "Trimming_in_progress", however the load pickup procedure is described in more detail below.

Slow balancing is not time critical. Therefore, DRZC slow balancing actions are relayed through the Resource manager and onto the ADMS. The ADMS will be responsible for instructing setpoints and trip commands to the available resource.

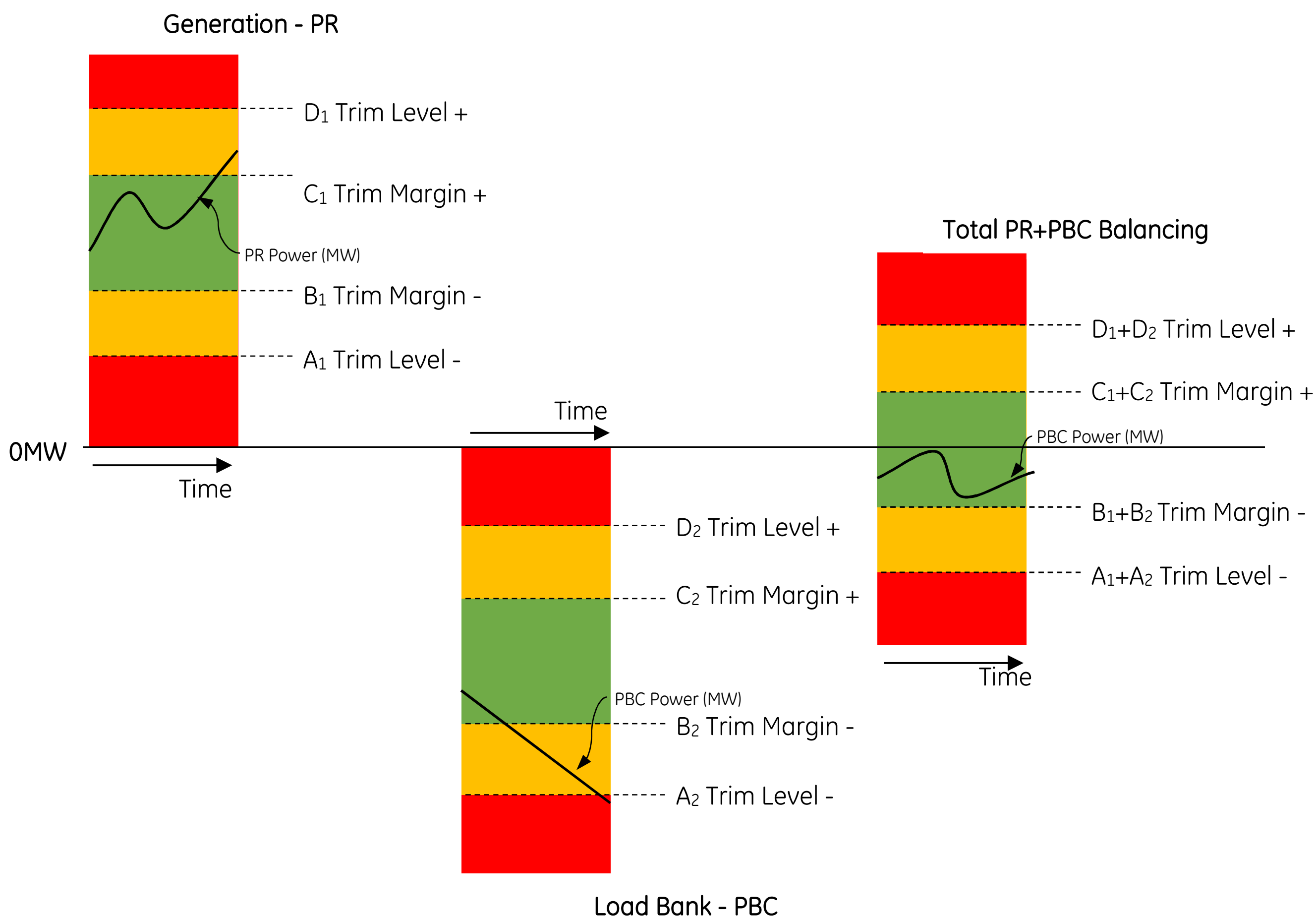


Figure 13 Trim Levels and Margins for Slow Island Balancing Process

5.4.2 Enabling, Disabling, Pausing and Resuming

The slow island balancing function is disabled on startup, as the no-load condition is outside both the anchor generators trim levels and regulation zone, and also outside the load banks trim levels.

The function can be enabled once the anchor generator and the load bank are within their respective trim margins (green zones in Figure 13). If there is a signal available via the ADMS to indicate that the anchor startup is complete, the ADMS and Trim Zone level checks can be used to cross-check the readiness to enable Slow and Fast Balancing.

Slow and fast balancing processes can both be enabled in parallel after the anchor generator has completed the startup procedure and is available. Both slow and fast balancing remain operational for the entire duration of island running from stages 3 through 5 (resynchronisation). Fast balancing is always armed, however there are some instances in which slow balancing will be temporarily paused:

1. Following a fast balancing trigger, the slow balancing action will be paused for two cycles, ensuring that at least one full cycle period passes between the fast balancing trigger and the next slow balancing action
2. An operator dispatch intervention may be required for larger load pickups, where the operator manually rebalances DER secondary resources (SBC1) and maximises load bank demand, prior to load pickup. In this case, the operator should manually suspend slow balancing prior to the load pickup. The load pickup will initiate a fast balancing action, which will indicate to the DRZC that slow balancing can be re-enabled on the second cycle after the fast balancing action (as per point 1 above). A timeout will be configured so that if the load pickup is not carried out or is smaller than expected, the slow balancing process is not blocked indefinitely.

5.4.3 Load Pickup Procedure with Slow Balancing

The DRZC will continuously report to the operator the value of load pickup that can be achieved in the current operating condition using the anchor generator and primary balancing control.

The value of load that can be picked up has two components; both are reported to the operator via the ADMS but the smaller value takes precedence:

ROCOF constraint {ROCOF_limit (-1Hz/s) * inertia} + {fast balancing load relief = load bank MW}

Balancing constraint Distance between PR+PBC and {D_1+D_2 trim limit}

If a load pickup operation is expected to add a smaller load than the pickup capability, then the slow balancing process carries on operating through the procedure. Fast balancing may occur, followed by slow balancing to re-adjust the levels of PR and PBC.

If there is an unexpectedly large load pickup, this is also managed by Slow Balancing by using some SBC capability, however there is a possibility that if there is insufficient DER resource available, there may be a load trip response.

However, if the operator is attempting to pickup a large load, which is greater than the current pickup capability that is determined by the monitoring process in 5.8.6, the following procedure is followed:

1. Disable Slow Balancing
2. Maximise Load bank capability to balance load pickup. Prior to load pickup, the island is balanced by increasing DER while anchor generator in maintained in green regulating zone
3. Operator initiates load pickup switching sequence
4. Fast balancing action is triggered by negative ROCOF

5. Resume Slow Balancing

5.4.4 Managing response deficits

Slow balancing isn't time critical as it manages the PR and PBC regulation margin rather than a hard constraint with associated protection actions. As such, there is a greater time budget for requesting additional resource from the ordered priority list (managed by the resource manager, see Section 5.6).

Slow balancing operates based on a settable cycle time which GE suggest should be in the order of 10-15s. If a resource doesn't provide the expected level of response, then the target value (MW setpoint within the trim margin) will not be met and the next resource in the ordered list will be triggered in the next slow balancing cycle. The resource will cycle to the next resource in the ordered list until the target value is met. Load tripping will be the lowest priority on the ordered list once all DER regulation capacity is used up.

5.4.5 Operational Examples

The following examples qualitatively illustrate the action of slow balancing in various scenarios.

Figure 14 Generator PR at D_1 Trim Limit+ → PBC response

> Describes a redispatch of load bank to return the anchor generator within the Trim_Margin levels. This scenario does not involve any Secondary Balancing Control as adjustment of Primary Balancing Control within the load banks margins is sufficient to restore the generator Proportional Regulation within the margins.

Figure 15 Generator PR at D_1 Trim Limit+ → SBC response

> In this case there is insufficient PBC resource to restore the generator PR within margins, so Slow Balancing calls on SBC resources to rebalance such that PR and PBC can return within margins.

Figure 16 Fast Balancing Event followed by Slow Balancing with SBC

> In this case, a Fast Balancing event is triggered which applies all available PBC (load bank) resource, therefore moving PBC outside the Trim Limit. Once Slow Balancing is enabled after the initial pause, it applies the standard Slow Balancing process first to deploy SBC resource (load shedding and SBC generation at capacity) and then adjust PBC to restore the normal PR and PBC margins.

Figure 17 Operator adding load when trimming is in progress

> This case looks at trimming coinciding with an operational procedure, using the example of a load pickup. It shows that trimming can continue while other actions are taking place.

Figure 18 Slow balancing triggering fast balancing

In certain circumstances, slow balancing (SBC2) can trigger load shedding leading to a fast balancing response. This example illustrates how this can occur and how it resolves through the standard Slow Balancing process.

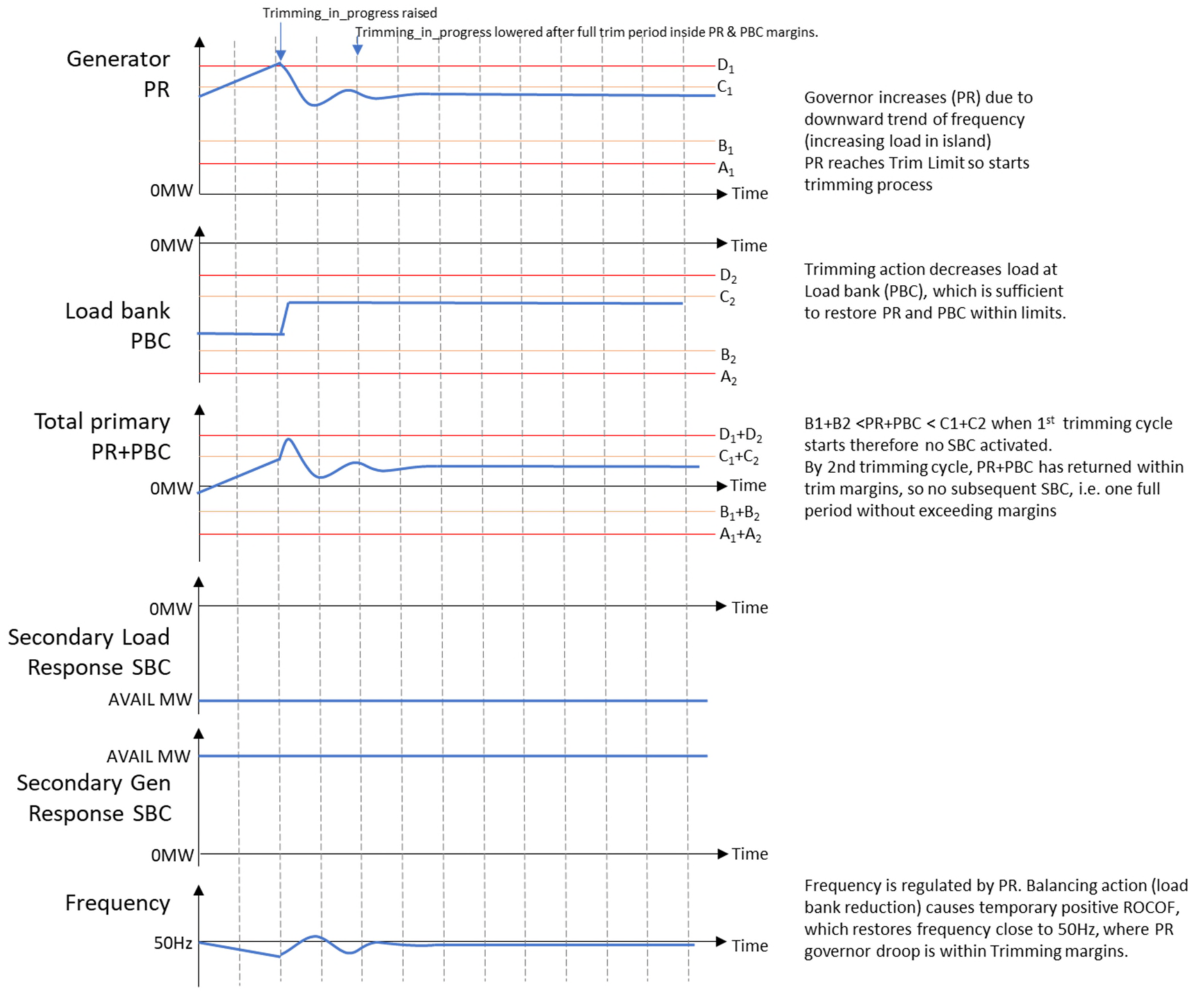


Figure 14 Generator PR at D_1 Trim Limit+ → PBC response

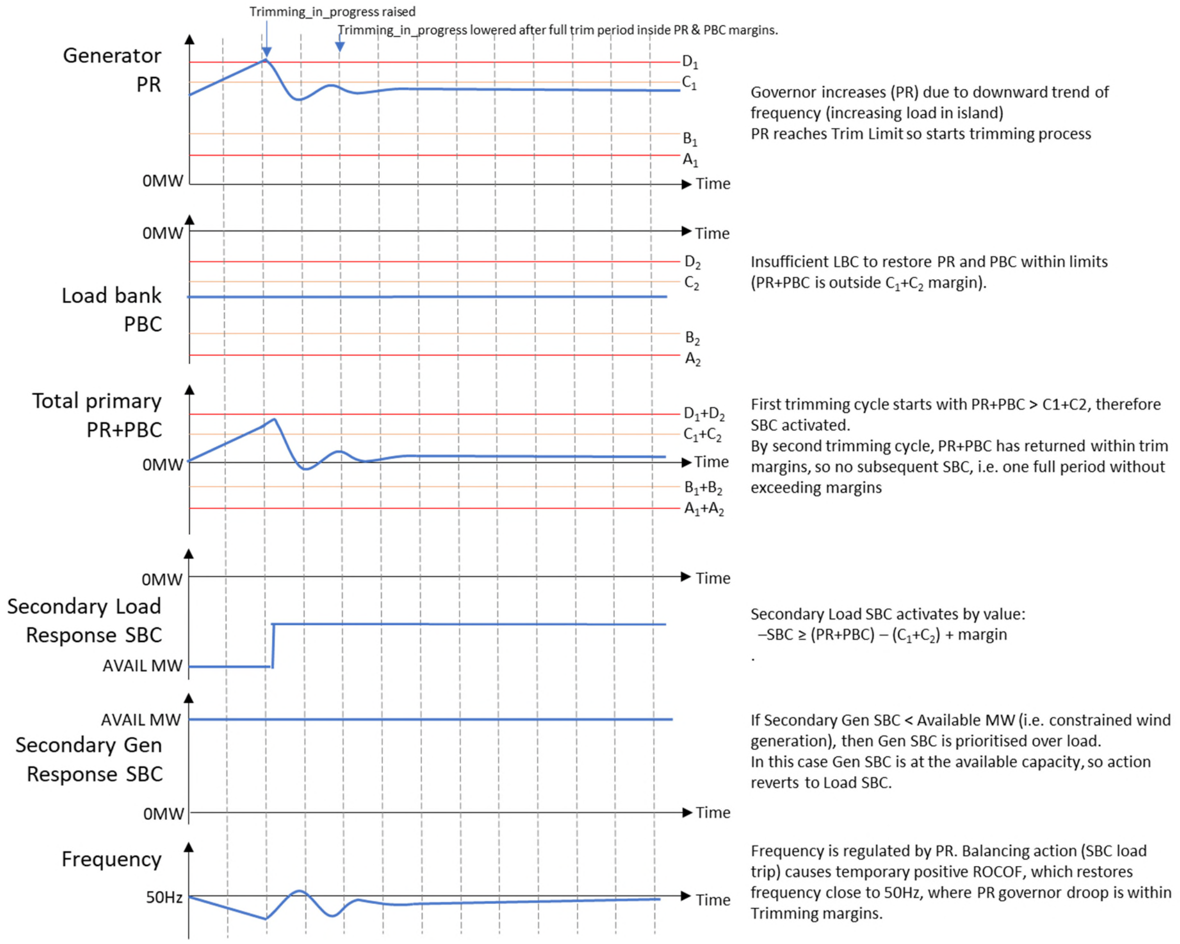


Figure 15 Generator PR at D_1 Trim Limit+ → SBC response

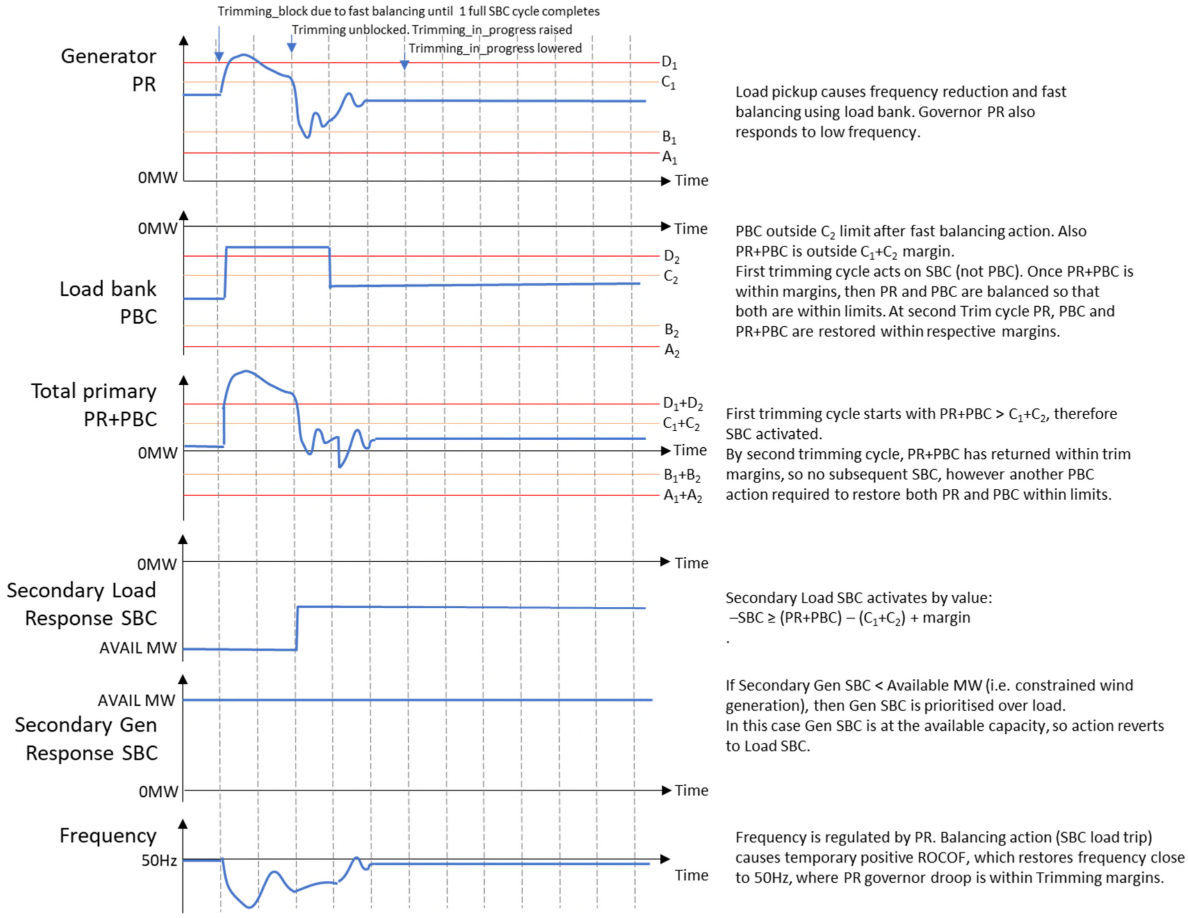
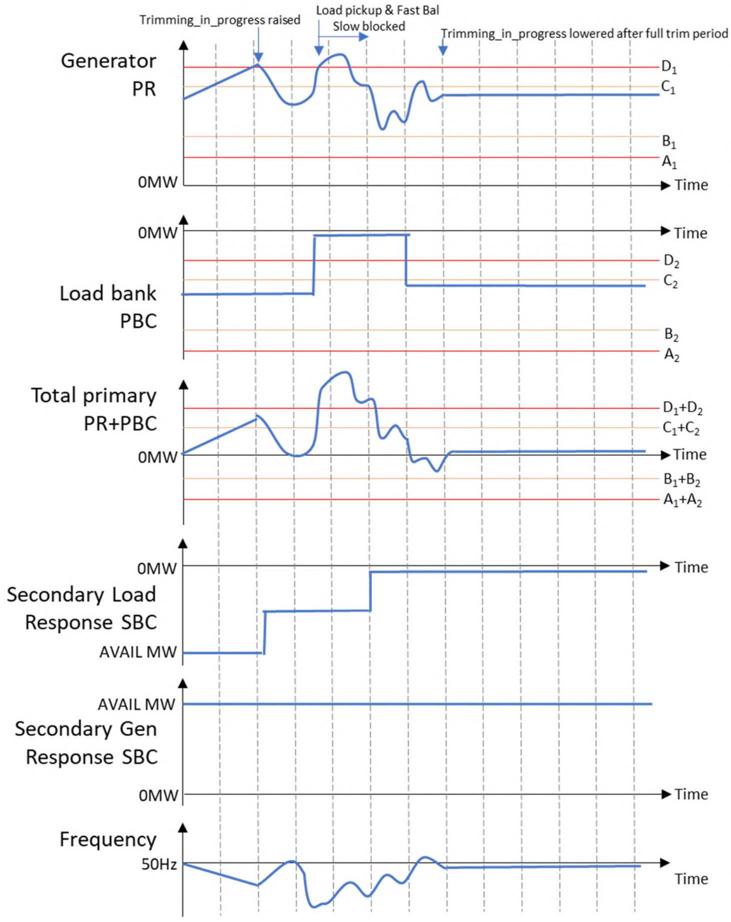


Figure 16 Fast Balancing Event followed by Slow Balancing with SBC



Governor increase (PR) due to downward frequency trend (load increase). PR reaches Trim Limit so starts trimming.
Load addition causes frequency disturbance, Gen PR increases output, crossing D_1 Trim Level+ again.
Fast balancing blocks Slow balancing for one full cycle, then SBC activates and Gen PR reduces.
Once (PR+PBC) within margins, PBC acts, PR follows frequency.

Insufficient LBC to restore PR and PBC within limits (PR+PBC is outside C_1+C_2 margin) – as previous example.
Operator adds load and load bank Fast Balancing response is triggered, moving PBC outside margins.

First trimming cycle starts with PR+PBC > C1+C2, therefore SBC activated.
Fast balancing pushes PR+PBC outside Trim Limits, but Slow Balancing initially blocked.
Once Slow Balancing unblocked, SBC action taken, followed after one more cycle with PBC response.
PR, PBC and PR+PBC remain within margins.

Secondary Load SBC activates by value:
$-SBC \geq (PR+PBC) - (C_1+C_2) + margin$ (in both cases).

If Secondary Gen SBC < Available MW (i.e. constrained wind generation), then Gen SBC is prioritised over load.
In this case Gen SBC is at the available capacity, so action reverts to Load SBC.

Frequency is regulated by PR. Balancing action (SBC load trip) causes temporary positive ROCOF, which restores frequency close to 50Hz, where PR governor droop is within Trimming margins.

Figure 17 Operator adding load when trimming is in progress

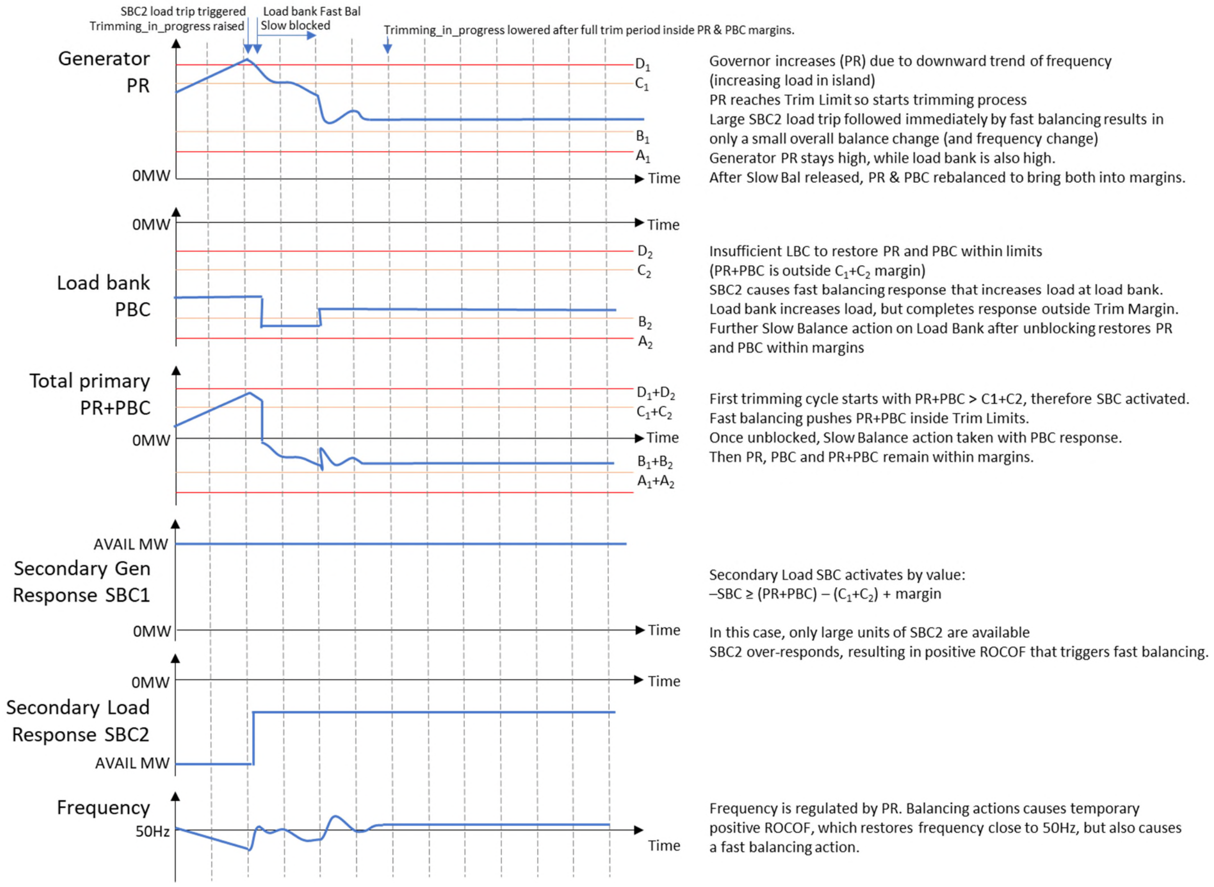


Figure 18 Slow balancing triggering fast balancing

5.5 Islanding/Resynchronisation

The success of resynchronisation depends on frequency difference and angle difference. It is also a function of the impedance between the areas being synchronised and on the inertia of the areas. Limiting the angle and frequency difference limits the power swing between the resynchronizing areas.

In the case of resynchronizing to the transmission grid, the transmission system can be considered an infinite bus with little or no impedance, and the impedance and inertia of the island network are the limiting factors.

Instantaneous power on breaker closure is determined by the angle difference and the impedance, in this case, we assume the angle difference between the anchor generator (approx. centre of inertia) and the transmission grid measurement.

Frequency difference on closure will lead to a power swing as power is imported or exported to accelerate or decelerate the region to match the frequency of the external grid.

The most onerous condition is closure on high frequency in the island and leading angle, or lagging angle and low frequency in the island. In either case, the power transfer will swing larger before returning to a steady state. Larger inertia in the island and connection to a large stiff system (rather than connecting two small islands) is the most limiting for frequency deviation.

The resynchronisation function measures the angle and frequency difference between the anchor generator and the other side of the resynchronisation boundary. It applies limits to the angle and frequency differences, and requires the value to stay within these limits for a preset time.

It detects success or failure of resynchronisation and if failure (by breaker closure and reopening) by observing the angle and frequency differences to ensure they stay synchronised for a preset period of time e.g. 15-30s.

5.5.1 Algorithm Description

5.5.1.1 Inputs

Inputs are phasor measurements from both sides of the resynchronisation boundary. This requires a measurement at the grid side and a measurement in the island. For example, a PMU measurement of the anchor generator point of coupling and a measurement from the 132kV bus or lines at the grid side would be sufficient.

All four measurements should be taken from P-class PMUs compliant with IEEE C37.118-2011 (rev 2014) standard with a sampling rate of 50 frames per second.

1. Voltage angle measurement from the island.
2. Voltage angle measurement from the grid.
3. Frequency measurement from the island.
4. Frequency measurement from the grid.

5.5.1.2 Outputs

1. Islanding state: A digital indicating whether the system is islanded or connected to the grid.
2. Resynchronisation Enabled: A digital indicating whether resynchronisation should be enabled or inhibited. This is will be used to assist the operator in the resynchronisation process

5.5.1.3 Settings

Table 10 below gives the configurable settings for the Islanding AFB. The values shown in the table are the ones used for the testing.

Setting Name	Value	Description
frequencyDifferenceThreshold	0.4 Hz	Threshold for detection of Islanding
angleDifferenceThreshold	1.483 radians	Threshold for detection of Islanding
angleThresholdPickUpDelay	12 samples	Delay in triggering based on angle difference. In this example this is set 240 ms.
islandingResetDelay	3000 samples	Delay in clearing the islanding event. In this example this is set to 60 seconds.
enableResynchFrequencyDiff	0.05 Hz	Upper limit of frequency difference for enabling resynchronisation.
enableResynchTimeDelay	1500 samples	Time delay to enable resynchronisation (30 seconds).

Table 10 Settings for the Islanding AFB

5.5.1.4 Islanding detection

The algorithm is based on thresholds on frequency and angle measurements. A large difference in either of the two quantities will trigger an Islanding detection.

Detection based on frequency difference triggers an islanding event immediately, while the detection based on angle difference has a delay of 240ms to account for possible measurement issues that could result in large spikes in angle.

An islanding event can be detected very quickly due to the large transients in frequency and angle following an islanding event. Large frequency differences usually occur due to the power imbalance in the island.

5.5.1.5 Resynchronisation Detection

Detection of resynchronisation is more challenging, as the resynchronisation transient could be smaller. It is also possible that the two islands' frequencies and angles become aligned for some time without them actually being synchronised. This requires a relatively long delay to clear the event to ensure successful resynchronisation. The event is cleared if frequency and angle differences fall below the thresholds for a configurable period of time. In the test case, a delay of 60 seconds was used to clear the islanding event and confirm resynchronisation. This ensures that the event was not cleared during the nearly half hour that the system was islanded.

5.5.1.6 Enable/Inhibit Resynchronisation

An enable/inhibit resynchronisation signal is provided to assist the operator in the resynchronisation process. This is based on the frequencies of the two islands being close for a configurable period of time. A pick-up timer with a delay of 30 seconds is used to enable resynchronisation, and there is no delay in returning to an inhibit state if the frequency difference exceeds the threshold.

5.5.2 Tests

Due to the unavailability of resynchronisation test cases for Chapelcross, real PMU signals of an islanding event followed by resynchronisation were used.

Acceptance criteria:

- Correct detection of Islanding.
- Event is not cleared before resynchronisation.

Figure 19 and Figure 20 show the angle difference and frequency for the entire test duration along with the Islanding detection flag ("islanding state"). The period when the system is Islanded can be easily identified from the angle difference chart showing values changing between +/- 180. It can be seen that the islanding flag remained high for the entire time the system was islanded. This is best observed on Figure 20 when the frequency signals are decoupled.

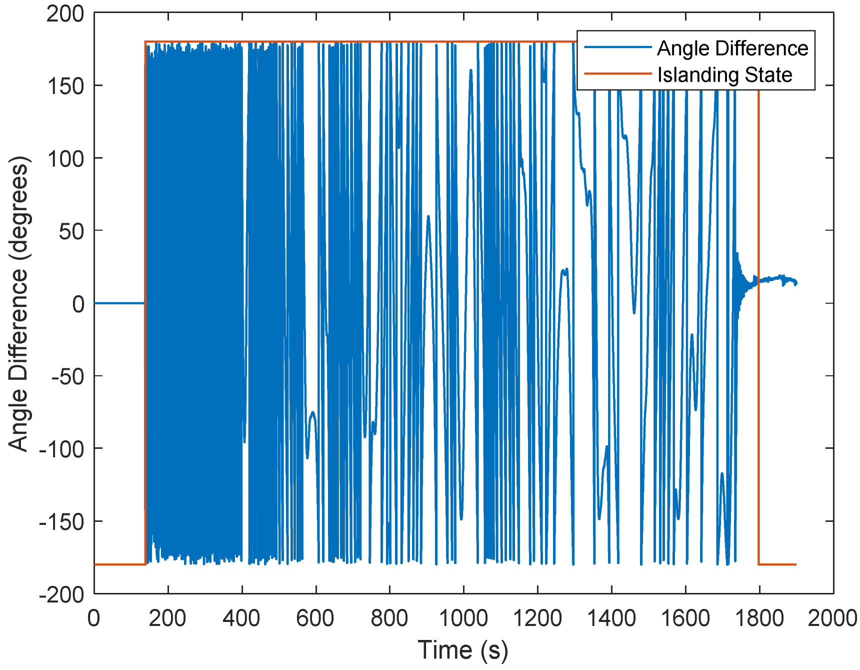


Figure 19 Angle difference across the resynchronisation boundary for the whole islanding event

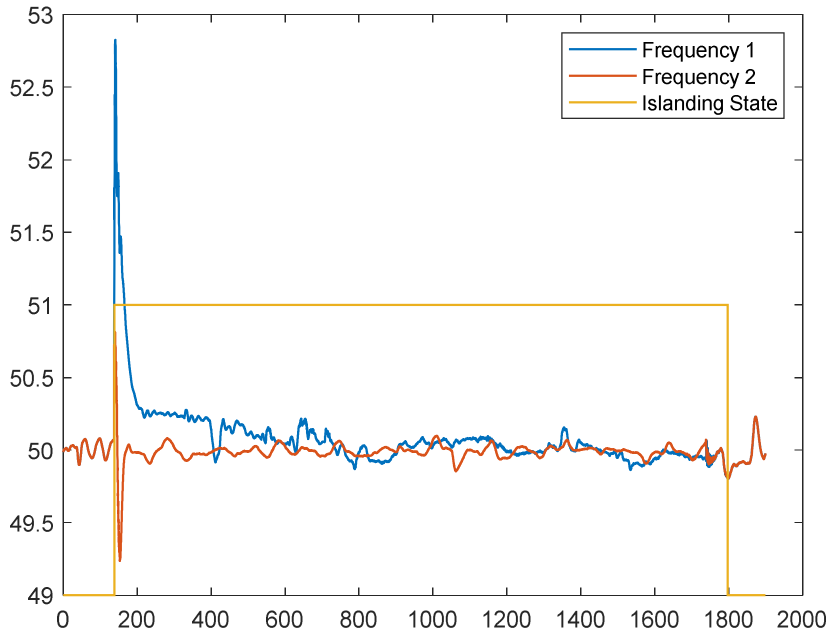


Figure 20 Frequency measurements for the whole islanding event

Figure 21 to Figure 24 show the detection and clearing times. The detection is almost immediate, and clearing the event takes about 60 seconds which is the configured delay for the islanding reset delay to confirm resynchronisation. The resynchronisation is clear in Figure 23 and Figure 24 where the angle difference stabilises and the frequency signals are synchronised.

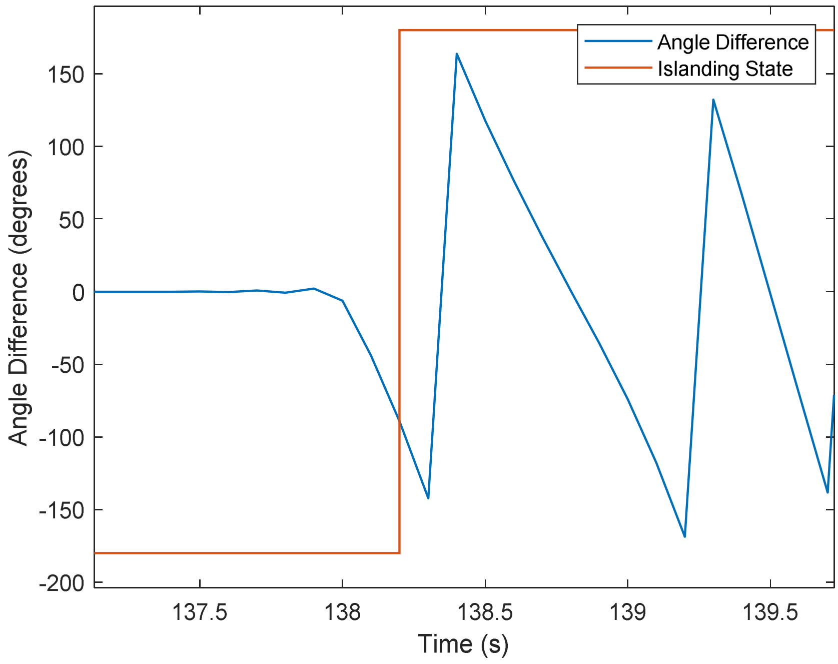


Figure 21 Angle difference across the resynchronisation boundary at the start of the event

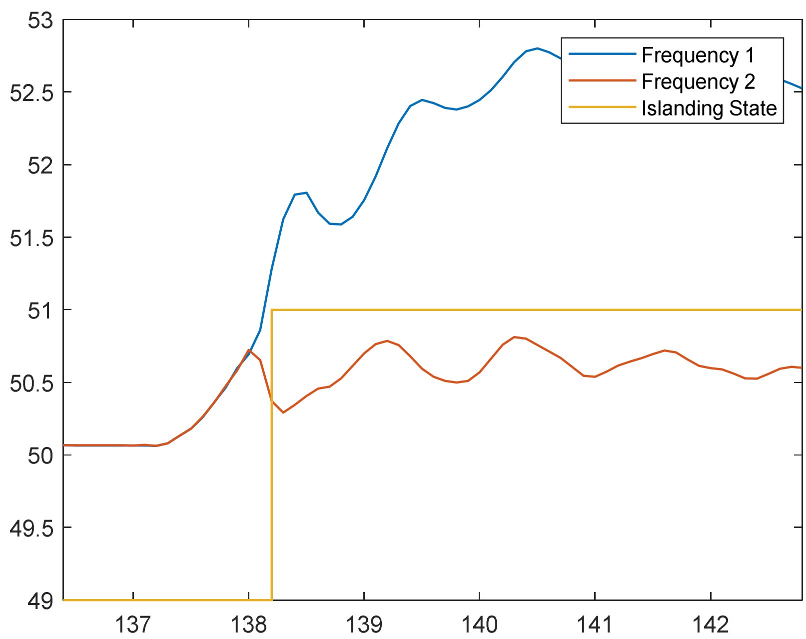


Figure 22 Frequency measurements at the start of the event

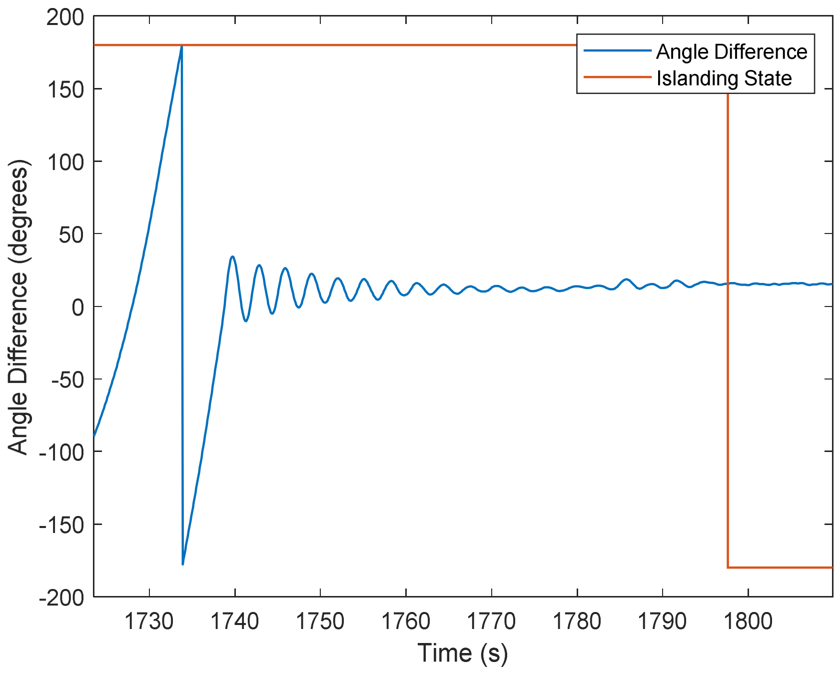


Figure 23 Angle difference across the resynchronisation boundary at the end of the event

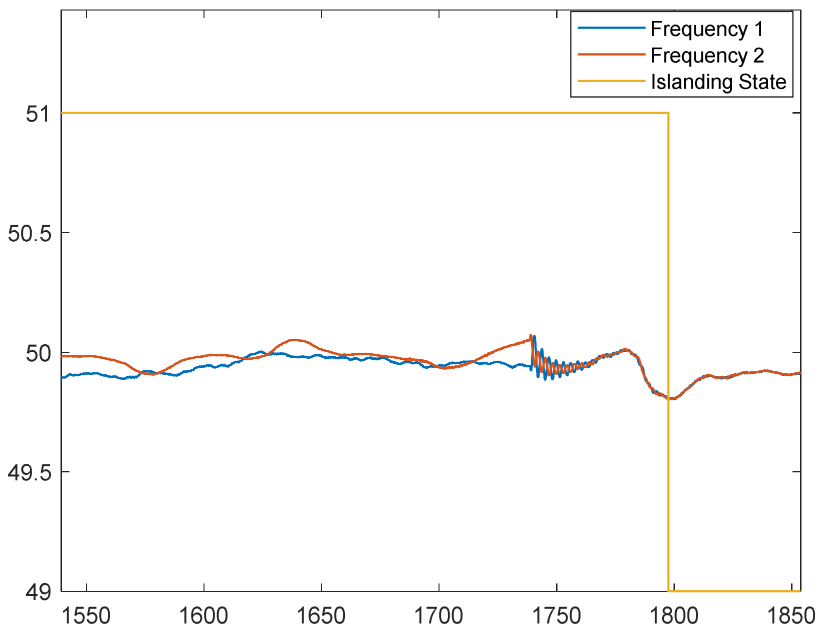


Figure 24 Frequency measurements at the end of the event

Figure 25 and Figure 26 show the frequency and angle difference against the resynchronisation enabled output of the AFB. It can be seen that the output is enabled during periods of small frequency difference and slow moving angle difference (given that the frequency difference is the rate of change of the angle difference).

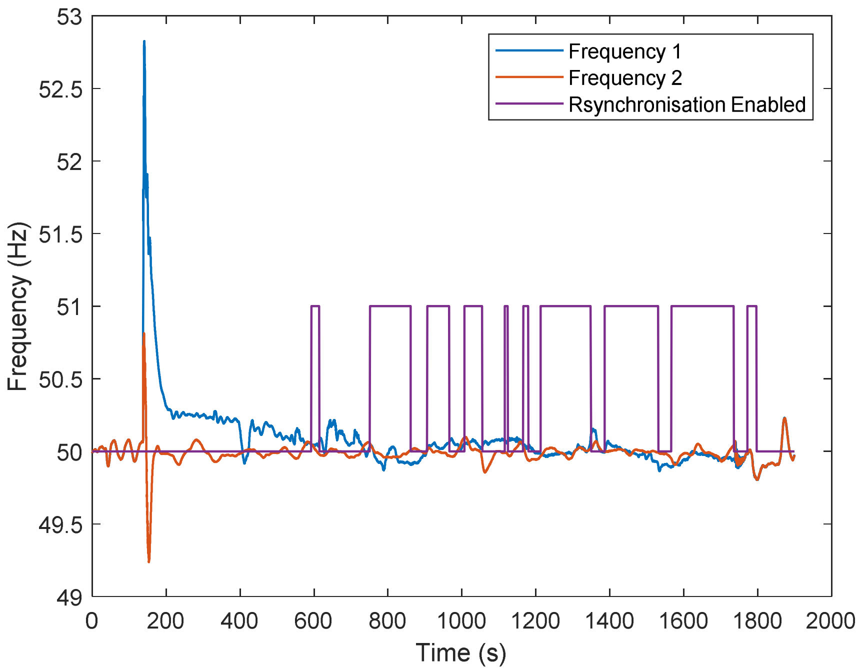


Figure 25 Frequency measurements and the Synchronisation Enabled signal

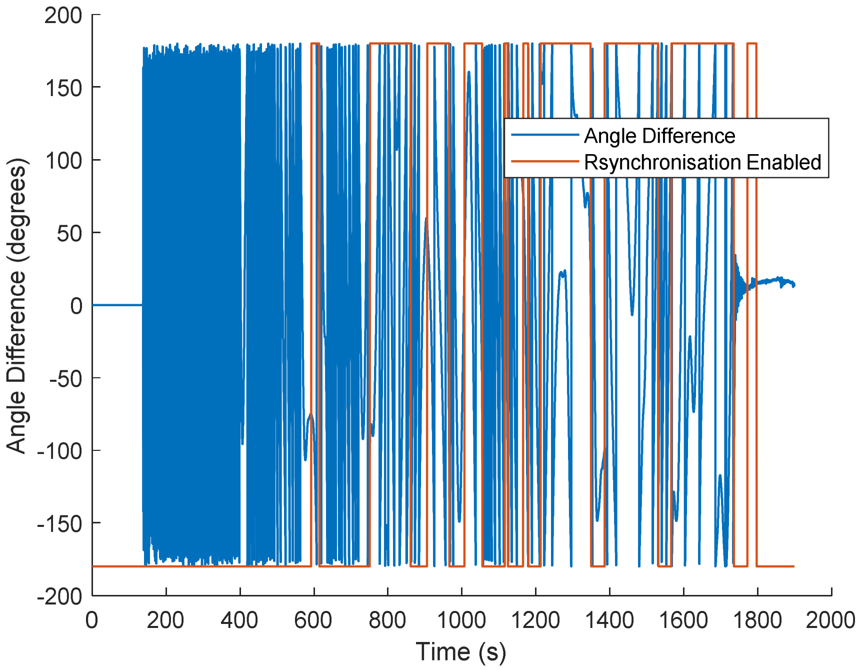


Figure 26 Angle difference and the Resynchronisation Enabled signal

5.6 Resource Manager

The resource manager is responsible for the aggregation and deployment of controlled resources for both fast and slow island balancing functions. It relies on information from the controlled resource and PMU measurements to ensure enough response is available to manage various planned and unplanned events.

Fast Balancing controls the Primary Balancing Control (PBC) resources (load bank) via the Resource Manager which dispatches the commands. To reduce latency, given fast balancing is time critical, the resource manager should instruct the load bank directly rather than through the ADMS.

PBC resources are fast acting devices, typically load bank and/or battery, which are used to balance the island in the event of a load loss, generation loss or load pickup. The Resource Manager receives a “FastTarget” MW value from the Fast Balancing block and applies the control to the available resources.

1. If the FastTarget value is less than the resource available, and the resource supports a setpoint value, the Resource Manager will dispatch the relevant setpoint.
2. If the resource does not support a setpoint value, the resource is assumed to be deployed as a single block such as a load or generator trip.
3. If there is more than one PBC resource, the Resource Manager will deploy the resources in order of priority defined in the setting parameters
4. If the FastTarget value is greater than the available resources, the Resource Manager will dispatch all available resources, and provided the operational process in Section 5.8.6 is applied, this will contain RoCoF within the specified limits.

In Chapelcross there is only one load bank as PBC resource, so there is no aggregation. However, in the rollout, it is expected that there may be combinations of load banks, batteries and non-critical sheddable loads that could provide the necessary speed of response to manage RoCoF.

Similarly, the Slow Balancing function will issue a “SlowTarget” MW value to the Resource Manager. The Resource Manager will track the PBC and SBC resources and order and stack them to ensure there is:

- Enough resource available to manage an event
- Classification of Secondary Balancing Control resources into SBC1 for preferred use and SBC2 for exceptional use, where SBC2 is typically customer load shedding
- Resource deployed in proportion to the SlowTarget value.

The Resource Manager will receive information from PMUs or from the ADMS on how much resource is available from each controlled plant. Once a Slow Balancing command is received, the Resource Manager will select the resources to deploy and send the appropriate dispatch commands through the ADMS. It will also keep a continuous record of the total available resources in each category (PBC, SBC1 and SBC2) which are made available for the operator to view and for archiving.

5.6.1 Recording and Aggregating Resources

The Resource Manager records and categorises the available resources. The resources are classified into:

Primary Balancing Control PBC	Fast-acting control such as load banks and batteries
Secondary Balancing Control SBC	Slower controlled resources
SBC1	Preferred resources such as DER raise/lower
SBC2	Second tier resources such as load shedding

The classification also divides the above resources into:

Positive	Increasing the power feeding into the island e.g. load bank power reduction, DER raise, load shed, battery export
Negative	Decreasing the power feeding into the island e.g. load bank power increase, DER lower, battery export

The classification is illustrated in Table 11. The input data to populate the data can be obtained from:

- Direct PMU data from resources
- SCADA values from the ADMS

The DER resource values must include a measure of the power available as well as the current operating power. This allows the DER units to be used as a positive balancing resource when the unit is constrained below the available power. In a case where a power available signal is not present from a particular resource, then it is replaced with the operating power and the DER can only be used as a negative balancing resource.

The total for each category is recorded and made available to operators and can be archived.

The function of stacking and distributing resources uses the lists of available resources to select and deploy the required volume of response.

Category	Available Resource	Total Available
PBC Positive[†]	Load_Bank [1] {operating MW} Battery [1] {export_capacity – operating MW*}	<sum> MW
PBC Negative[†]	Load_Bank [1] {capacity – operating MW} Battery [1] {import_capacity + operating MW*}	<sum> MW
SBC1 Positive[†]	DER_wind [1] {P_available – operating MW} DER_wind [2] {P_available – operating MW} ... DER_wind [*m*] {Pavailable – operating MW}	<sum> MW
SBC2 Positive[†]	Cust_Load [1] {operating MW} Cust_Load [2] {operating MW} ... Cust_Load [*n*] {operating MW}	<sum> MW
SBC1 Negative[†]	DER_wind [1] {operating MW} DER_wind [2] {operating MW} ... DER_wind [*m*] {operating MW}	<sum> MW
SBC2 Negative[†]	n/a	n/a

* battery operating MW defined with battery export as positive value

[†] positive values are capacity to increase power balance in the island, e.g. generation increase, load shed, battery export; negative values are capacity to decrease power balance, e.g. generation reduction, battery import

Table 11 Classification of Resources for Fast and Slow Balancing in the Resource Manager

5.6.2 Stacking and Distributing Resources

Resource stacking combines multiple contributions within the relevant category in Section 5.6.1 to deliver a total response.

The process of resource stacking is as follows and is applied in the same way for PBC (fast) and SBC (slow) resources, and for the positive and negative power balance responses. The algorithm selects the resources that match or exceed the FastTarget or SlowTarget value issued by the balancing functions.

The selection logic is as follows:

1. Resources are stacked with largest as #1 and smallest as #N
2. Target is received from Fast or Slow Balancing
3. Find Block_i, such that $\text{Block}_i < \text{Target} < \text{Block}_{i+1}$
4. If $(\text{Block}_i - \text{Target}) < (\text{Block}_{i+1} + \text{Block}_{i+2} - \text{Target}) \rightarrow$ Select Block_i
5. Else select consecutive blocks from ($i+1$) until the sum exceeds Target

For selecting preferred SBC1 and second-tier SBC2 resources, the above logic is applied first to the SBC1 list (positive or negative as appropriate). In the case where all SBC1 is used, the remainder (Target-TotalSBC1) is then dispatched to SBC2 resources using the same method.

At this stage, it is proposed that PBC is treated as variable resource, while SBC is treated as blocks that are dispatched as entire units. It would be possible to refine the approach to use variable resources where they exist. If a variable resource exists in the selected blocks AND if the Target is smaller than the sum of blocks, the response can be fine-tuned by issuing power setpoints to the variable resources such that the dispatched volume matches Target volume.

5.7 Voltage management

The DRZC is capable of voltage management through estimation of system strength during energization steps from changes in voltage and reactive current.

5.7.1 System strength

Estimates of the system strength can be obtained during energization steps where a change in reactive loading causes a change in voltage magnitude. Low system strength implies a larger change in voltage magnitude for a given change in reactive current (higher system impedance). The system strength measure could be used in the control room to tap voltage higher than normal before energising a transformer for example. Alternatively, the system strength could be used to arm fast voltage control response from BESS or other devices capable of voltage control.

The DRZC can provide information to the ADMS which may automatically (or manually) tap voltage to prepare for a large reactive low. It is assumed the primary voltage control comes from other local voltage control active in the grid.

5.8 Supporting functions and systems

5.8.1 Measurements

This section outlines the measurement requirements for the GE DRZC. This includes the geographical locations of the measurement devices, as well as the measurement signal requirements in terms of accuracy, speed and resolution. The requirements include redundancy to ensure the communications and cybersecurity requirements are met.

The Phasor Measurement Units (PMUs) will monitor voltage and current phasors (magnitude and angle), as well as the frequency. The power and reactive power, as well as the RoCoF is derived from the fundamental signals within the DRZC. Only positive sequence phasors are required as phase imbalance is not managed by the DRZC.

PMUs capable of measuring voltage and current signals at 50FPS sampling rate would be installed to measure primary circuits connected at Chapelcross 33kV bus, the outputs of the configured DER, anchor generation and load bank, and at least one PMU at transmission level for resynchronisation purposes. Some PMUs can measure up to 4 x voltage 3-phase buses and 4 x 3-phase circuits, which would reduce the number of PMUs required by the DRZC to manage the island.

Figure 27 Schematic showing the hardware installations for the Chapelcross 33kV system and communications protocols. This is based on the 2 x WAN's with PRP ports architecture outlined in Section 4.1.5 of the communications report [1]

The PMUs should meet or exceed the IEEE C37.118-2011 (rev_2014) standards and be configured to stream data at a 50 FPS update rate. P-class measurements should be configured to reduce the PMU processing latency while maintaining the measurement accuracy for synchrophasor-based control.

Figure 27 shows the required hardware for the DRZC scheme with redundancy with communications protocols.

PMUs will measure either bus or line voltage depending on the availability of measurement VT's. Current is measured via measurement CT's. The transmission PMU will provide the voltage phasor angle and frequency to enable successful resynchronisation.

Location	Number PMUs	Description
Chapelcross 33kV substation	6	Measure primary loading (if full 11 circuits are monitored)
Ewe Hill	2	WF output
Minsca	2	WF output
Stevens Croft	2	Loading and frequency
Load Bank	2	Loading
Transmission	2	MITS frequency and angle
TOTAL	16	

Table 12 Locations and number of PMUs

Table 12 contains the PMU measurement requirements in terms of location and number of PMUs. The level of redundancy required to meet the availability criteria means that 2 x PMUs would be installed at the key measurement and control sites within the DRZ. The number of PMU devices in Table 12 is based on the GE DR60 PMU that can be configured with 16 VT and CT inputs (4 x 3ph currents and 4 x 3ph voltages). For example, to measure the 11 primary circuits connected at Chapelcross 33kV, 3 x DR60s would be needed (total of 6 to provide redundancy). This assumes a suitable layout of the substation VTs and CTs and that the 3 x PMUs can be installed at locations to access these VTs.

5.8.2 DRZC Controller Location

GE envisages that 2 x PhasorController devices (master DRZC) will be installed at the Chapelcross 33kV substation to provide redundancy. These will both monitor the distribution grid status and take control actions when necessary to maintain island operation as well as supervising resynchronisation.

5.8.3 Validate Zone Black

Before starting the process, the operators must confirm that the network is de-energised to avoid a safety issue with the network in an unknown state.

Real-time visualisation of voltage phasor measurements in the control room is available to confirm that the network is de-energised. The WAMS view can be used to cross-check with ADMS.

The voltage phasors measured from the anchor generator point of connection and all other available voltage phasors that are required to be zero are presented in an operator's real-time view showing the voltage magnitude component (not angle). If any of the voltages are shown as live, this indicates that the zone is not black.

The operator will also be able to observe voltage magnitude measurements on ADMS and can confirm between the two systems that there is no live voltage in the region to be restarted.

5.8.4 Monitor Anchor Generator Startup Dynamics

As the anchor generator starts up, it passes through sensitive light-load operating points until the minimum load level of the generator is reached. During this time, governor stability could be a problem. If governor instability occurs, it is likely to appear as low frequency oscillations in the electrical frequency at the generator terminals.

To monitor this in real-time, a high-resolution chart fast-update chart should be available showing PMU-based frequency from the PMU(s) at the anchor generator. The charts are available both to the control room operator and to the anchor generator local operators if the station is manned.

High resolution charts reproduce the full native resolution of phasor measurements, with charts updated every 1 second with 50 samples of incoming data. Charts can be configured to show between 1 and 3 minutes of real-time high-resolution data which captures any governor-related oscillations.

Instability and near-instability are easily identified by observing the high-resolution chart. Oscillation amplitude takes time to grow and operators have can select from pre-defined courses of contingency action that improve stability in light loading, such as:

- Reduce gain of frequency regulation (increase droop)
- Temporarily switch off governor frequency regulation and manually balance until a minimum or stable operating point achieved

5.8.5 Monitor Voltages and Alarm

The DRZC actively controls frequency while voltage is managed by the anchor generator AVR and other local closed loop controls e.g. transformer tapping.

Although not used in control, phasor measurements provide a very useful resource to monitor the voltage regulation in far greater detail than SCADA measurements. For example, after a reactive load pickup such as lines or transformer energisation, it is useful to observe the effect on voltage, including high or low transient voltage excursions and the occurrence of delayed voltage recovery. If there are unusually large voltage disturbances with network energisation, it may guide the operators to select a variant of the process with more conservative reactive load pickup.

Voltage views will be available from phasor measurements as:

- Standard live updates on 15-minute charts with navigation to specific voltage measurements
- Easy navigation from live charts to zoom into full resolution record e.g. of a network segment pickup
- Pre-configured 1-3 minute high-resolution live charts for selected voltage measurements

- Pre-configured live and historic views of voltages throughout the island
- View of external grid voltage for awareness of the state of the grid and readiness for resynchronisation

All voltage phasors will be recorded for later analysis.

5.8.6 Fast Balancing Operational Margin Monitoring

A control room monitoring function is planned to determine the level of positive or negative power balance step-change disturbance that can be sustained without violating frequency and RoCoF limits. This is presented to the operator as a table that can be compared with the load pickup expected in the next operation. The table can also be used to compare with the maximum N-1 contingency that may be experienced in the system.

The table includes the requirements for respecting RoCoF and frequency limits given the inertia available in the system and the volume of frequency regulation and balancing reserve available.

A power imbalance in the island results in RoCoF, which is sustained until the load and generation return to a balance point, at which RoCoF=0 at the frequency nadir/zenith. The first criterion is that RoCoF will stay within +/-0.8Hz/s as described in Section 5.3.2.

Net power imbalance (ΔP_{imbal}) in the island can be extracted from ROCOF and inertia:

$$\Delta P_{imbal} = \frac{2H}{f_o} ROCOF$$

To ensure that the RoCoF remains within limits, it is necessary to contain the power imbalance such that:

$$-0.8 * \frac{2H}{f_o} \leq \Delta P_{imbal} \leq +0.8 * \frac{2H}{f_o}$$

The largest sustained value of ΔP_{imbal} during a disturbance comprises the system event less the fast-acting response that is deployed within the 0.75s window before loss of mains triggering. In effect, the power imbalance ΔP_{imbal} is the difference between the size of the system event causing an excess of power (P_{excess}) and the fast balancing response capability. P_{excess} is positive for a load loss, and negative for a deficit due to load pickup or generation trip.

In general form, the convention used is that an excess of power in the island is positive, leading to positive RoCoF.

$$\Delta P_{imbal} = P_{excess} - P_{fast\_bal}$$

Thus:

$$-0.8 * \frac{2H}{f_o} \leq P_{excess} - P_{fast\_bal} \leq +0.8 * \frac{2H}{f_o}$$

For clarity in the presentation to the operator, values will be presented for negative RoCoF and positive RoCoF. The negative RoCoF value is a limit for load pickup and generation trip, while the positive RoCoF value is the limit for load tripping leading to high frequency response. For island operation, N-1 security is achieved if the maximum credible load or generation loss are within these values.

As well as respecting RoCoF limits, the island must be operated with sufficient reserve that a frequency deviation must be balanced by proportional regulation (PR) at the anchor generator and fast Primary Balancing Control (PBC) at the load bank. The frequency capability is shown in Table 13 . The table can be presented in both the WAMS and ADMS systems.

Negative ROCOF Load pickup / Gen trip limit ($P_{deficit\_max}$)	MW	$\left[0.8 * \frac{2H}{fo} + P_{load\_bank}\right]$ (A)
Positive ROCOF Load trip limit (P_{exess_max})	MW	$\left[0.8 * \frac{2H}{fo} + (P_{lb\_max} - P_{load\_bank})\right]$ (B)
Negative Frequency Balancing	MW	$\{Anchor_{HighRegLimit} - AnchorPower\} + P_{load\_bank}$ (C)
Positive Frequency Balancing	MW	$\{AnchorPower - Anchor_{LowRegLimit}\} + \{P_{lb\_max} - P_{load\_bank}\}$ (D)
Low frequency capability	MW	Min { (A), (C) }
High frequency capability	MW	Min { (B), (D) }

Table 13 Frequency Capability Table presented to operator to confirm security of frequency in load pickup and unplanned disturbances

Other resources can easily be included, for example if two Distributed ReStart Zones are combined and two PR anchor generators provide droop response, or if two or more PBC resources such as batteries and load banks operating together.

<u>Assumption for Frequency Balancing</u>

It is assumed that there is time for PBC resources and frequency regulation to deploy before the frequency violates the G99 limits. The time available includes the time for frequency to move from near 50Hz to the F±1.4Hz limit, plus the delay in UF/OF relays (0.5s, see Table 4). Thus, the limits on load pickup are defined only by RoCoF considerations and available resource to balance an event.

If there is a risk that proportional regulation cannot respond in time, then a more conservative RoCoF limit can be applied, accompanied by:

- Reduced load pickup through ADMS switching or unplanned outage size limit
- Some fast-response SBC resources incorporated in PBC e.g. non-critical load tripping and generation tripping.

However, this is outside the current scope, as it is understood that governing response at Steven's Croft is sufficiently fast.

5.8.7 WAMS View, Report, & Log

The Wide Area Measurement System provides a valuable resource for real-time views and historic analysis. The WAMS system will record and present all PMU data as well as derived analogue values and digital triggers from the DRZC.

Historical recording is flexible to configure, but a typical setup includes:

- Continuous full-resolution data at 50Hz recording for 6 months data
- Lower resolution data at 1Hz recording for 2 years
- Long-term snapshot storage (for auditing) of all PMU records for specific times for indefinitely retaining test and activation data for a total of 2 months, copied automatically using alarm triggers or manually by an analyst following an event.

Alert and alarm thresholds can be set up on individual signals, and logical combinations of alarms can be applied. Hysteresis can be applied to the alarms so that issues such as delayed voltage recovery can be flagged if the condition remains for a given length of time. Dynamics alarms on oscillations or transients can be set up.

The logical combination of alarms can be used to create high level summary alarms that can be sent to the ADMS.

In a related project in Westfjords, Iceland, PMUs were used to tune the control for running the 11-33kV network in island mode, and continues to be used for control room monitoring and analysis of the network. The frequency and voltage during a Black start and energisation are shown in the example in Figure 28. This illustrates the detail of dynamic information from PMU measurements, in contrast to steady-state information available from SCADA measurements.

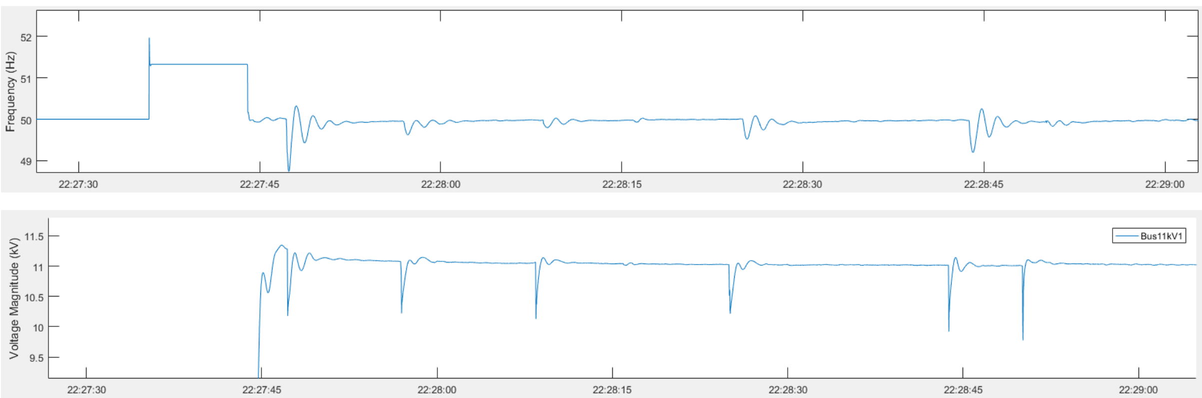


Figure 28 Example of PMU measurements of Distribution Island Energisation in NW Iceland

5.8.8 ADMS Switching Sequences and Automation

The ADMS includes the capability to automate switching sequences and other tasks that would otherwise require significant manual effort by a control room operator. By using these facilities, the task of supervising the Distributed ReStart process is greatly simplified.

At this stage, it is proposed that the operator will have a number of high-level actions to apply in the sequence, but operators will not have to carry out detailed manual switching procedures. A full end-to-end automation process is not recommended due the uncertainties in the ambient conditions such as available renewable resources and network outages that may require some operator judgements on alternative restoration paths.

ADMS involvement in the ReStart process is planned for:

- Switching sequences and automation for
  - Configuring the network topology to a known initial state for Black starting
  - Switching protection settings groups to island mode using the Automation Application
  - Restoring grid-connected protection settings groups after resynchronisation
- Operator initiates load pickup stages via ADMS – this may be just individual breaker close, but possibly there may be more complex sequences, e.g. staggering load pickup to manage RoCoF
- Operator visualisation in ADMS of the island incorporating high level alarm indications and resource availability interchanged between the WAMS system and ADMS.

6 Non-functional Specification

6.1 Design Processes and Applicable Standards

The final design of the system needs to consider various processes and meet existing industry standards requirements. The end-to-end system must be implemented in accordance with the recommended approaches and should be fully evaluated to detect any non-compliance. Where the designed system is not compliant, the severity of the effects should be investigated and where necessary, the roadmap and plans toward full compliance should be determined.

6.1.1 Safety Assessment

The safety can be defined as freedom from unacceptable risk of physical injury or of damage to the health of people, either directly, or indirectly as a result of damage to property or to the environment. Functional safety is part of the overall safety related to the correct operation of a system or equipment in response to its inputs. The future ReStart system derived from this project needs to be designed in such a way as to prevent dangerous failures or to control them when they arise. Any safety strategy must consider not only all the elements within an individual system (for example PhasorControllers, sensors etc.) but also all the safety-related systems creating the total combination systems.

6.1.1.1 IEC 61508

IEC 61508 international standard covers those aspects to be considered when electrical / electronic / programmable electronic systems are deployed to perform safety functions and it provides the requirements to minimise safety-related failures. It offers a safety lifecycle model that will serve any project and considers all lifecycle phases including initial concept, through design, implementation, operation and maintenance to decommissioning.

Two types of requirements are necessary to achieve functional safety:

- safety function requirements – the objectives and services that must be provided by a safety function.
- safety integrity requirements – the likelihood of a safety function being effective and satisfactory as planned.

The safety function requirements are identified from the hazard analysis and the safety integrity requirements are determined from the risk assessment. The higher the level of safety integrity, the lower the likelihood of dangerous failure.

According to IEC 61508, the system design should be checked against 3 types of failures:

- Random hardware failures
- Systematic failures
- Common causes failures

IEC 61508 provides a basic and generic standard for functional safety. Therefore, various industry sectors provide their own specific standards and guidelines as needed, such as IEC 61513 for the nuclear sector, IEC 62061 for the machine safety sector, and IEC 61511 for the process control sector.

6.1.1.2 IEC 61511

IEC 61511 is a process industry derivative of IEC 61508. Although the underlying approach used within IEC 61511 is specifically aimed at the protection issues surrounding process plant – handling, transporting and storage of products – it may also be applied to the protection of equipment and systems that are used as part of electricity supply, including the machinery involved in that process. Process safety is best achieved by using inherently safe processes. However, when this is not practical or possible, protective systems are required to mitigate the risk of hazards to an acceptable level. Functional requirements for these protective systems are determined from a Hazard and Risk Assessment (H&RA).

IEC 61511 gives requirements for the specification, design, installation, operation and maintenance of a safety instrumented system (SIS), so that it can be confidently entrusted to achieve or maintain a safe state of the process. Implementing an SIS lifecycle management system provides a framework for managing people, processes, and systems to improve overall safety and operational performance. SIS is responsible for safe operation and ensuring the emergency stop within the limits considered as safe, whenever the operation exceeds such limits. The main objective is to avoid accidents, such as fires, explosions, equipment damages, protection of production and property and, above that, avoiding life risk or personal health damages and catastrophic impacts to community. It should be clear that no system is completely immune to failures and, even in case of failure, it should provide a safe condition.

It is important to include cyber security in the requirements for the identification and management of threats. Whilst IEC 61508 was the first functional safety standard to define the requirements for cyber security through use of internationally recognised standards for cyber security, namely IEC 62443, IEC 61511 has gone further by referring to two additional cyber security-related standards ISA TR84.00.09 and ISO 27001.

6.1.2 Layer of Protection Assessment (LOPA)

A process hazard analysis (PHA), such as Hazard and Operability Study (HAZOP), is useful in identifying potential hazard cases; however, a PHA can only give a qualitative indication of whether sufficient safeguards exist to mitigate the hazards. LOPA is the methodology for hazard evaluation and risk management that can provide a more detailed, semi-quantitative assessment of the risks and layers of protection associated with hazard scenarios. It helps to identify the scenarios that present the most significant risk and determines if the consequences could be reduced by the application of inherently safer design principles. LOPA can also be used to identify the need for SIS or other protection layers to improve process safety in accordance with the IEC 61511 standard. In fact, LOPA builds upon well-known process hazards analysis techniques and should be typically applied after a qualitative hazards analysis has been completed.

6.1.3 Failure Modes and Effects Analysis (FMEA)

FMEA is a systematic method of evaluating an item or process to identify the ways in which it might potentially fail. In addition, it is used to study the effects of the mode of failure upon the performance of the item or process and on the surrounding environment and personnel. Understanding and addressing failure modes and their subsequent effects and criticality (including probability of occurrence and level of severity) significantly reduces non-productive time and safety-related incidents. The purpose of performing an FMEA is to support decisions that reduce the likelihood of failures and mitigate their effects. Therefore, FMEA can improve reliability, reduce environmental impact, reduce procurement and operating costs. The IEC 60812 standard gives general guidance on how to plan, perform, document and maintain an FMEA.

FMEA can be carried out several times in the lifetime for the same item or process. For this project, a preliminary analysis has been conducted with the focus on GE items and processes according to the early stages of design and planning. However, this analysis needs to be followed by a more detailed analysis considering all aspects of the end-to-end system and in collaboration with other project associated participants.

6.1.4 Software Testing

It is necessary to test software before it is released to the users to reduce the risk of mistakes in software production having a negative impact once deployed and operational in the system. Software testing should focus on providing information about a software product and finding as many defects as possible, as early as possible in the development process, under given constraints of cost and schedule. The IEC 29119 series of software testing standards aim to provide stakeholders with the ability to manage and perform software testing in any organization. It describes the role of software testing in an organisational/project context and defines how software testing fits into different life cycle models.

Testing is the primary approach to risk treatment in software development. IEC 29119 standard defines a risk-based approach for testing. Risk-based testing is a recommended approach that allows testing to be prioritised and focused. It should be noted that the standard only addresses testing and it does not address the other activities of validation and verification. To provide complete validation and verification of a product, it is required to use this standard in conjunction with other standards, including IEC 12207 and IEEE 1012.

6.1.5 Software Life Cycle Process

A life cycle can be described using an abstract functional model that represents the conceptualisation of a need for the system, its realization, utilization, evolution and disposal. The IEC 12207 standard, Systems and software engineering — software life cycle processes, defines a set of processes, which can be used in the definition of the systems life cycle. It helps to provide life cycle policies, processes, models, and procedures that are consistent with the organizations objectives, that are defined, adapted, improved and maintained to support individual project needs. Such processes are applicable during the acquisition, supply, development, operation, maintenance or disposal of software systems, products, and services. These life cycle processes need to be accomplished through the involvement of stakeholders, with the ultimate goal of achieving customer satisfaction. IEC 12207 is intended to be compatible with the quality management system specified by ISO 9001, the service management system specified by ISO/IEC 20000-1, and the information security management system specified by ISO/IEC 27000.

6.1.6 Communications

The implementation of this project requires extensive data communications and employing of equipment, including controllers, measurement devices, Ethernet switches, routers, etc. The project involves mission-critical applications, such as control functions, alongside the use of widespread communication technologies and devices. Data errors and failures in any of these items can result in an incorrect operation. Therefore, it is important to make sure that communication equipment can operate reliably according to the exiting industry standards. IEEE 1613, Standard Environmental and Testing Requirements for Communications Networking Devices in Electric Power Substations, specifies service conditions, ratings, and environmental performance and testing requirements for communications devices used in the substation environment. In addition, IEC 61850 is an international standard that defines a wide range of communications protocols for electronic devices at electrical substations. This standard is divided into 10 parts, with IEC 61850-3 covering EMI (electromagnetic interference) immunity and other environmental requirements.

6.2 Testing methodology and stages

6.2.1 Development

There are two main stages of testing that are recommended during the development, namely *software-in-the-loop* and *hardware-in-the-loop.*

6.2.1.1 Software-in-the-loop

Software-in-the-loop (SiL) testing is used to test code/algorithms in a modelling environment. It is recommended to first perform open-loop testing, where the algorithms are driven using simulated data to verify the high-level functionality of the algorithms. Once open-loop testing in a software environment is completed, closed loop testing can be performed, but it is necessary if there is a suitable platform for hardware in the loop testing. Creating a harness between an environment that could run control algorithms and the conventional power system simulation tools, (e.g. DigSilent, PSS/e), is complex and non-standardised, therefore it is recommended to perform sufficient testing in the SiL environment to ensure high confidence on the high-level features of the scheme.

The open-loop simulations are usually driven by a set of outputs from a simulated power system scenario, therefore it is important to have a detailed set of scenarios which can cover the different operating criteria of the scheme.

It should be noted that because this simulation is open-loop, the output of the code will not be able to impact the state of the power system, therefore only certain components can be tested in this manner. For example, detection of an event and its corresponding request for a control action can be tested, but not how the control system would respond after such control action was taken. This would be testing in closed loop testing.

6.2.1.2 Hardware-in-the-loop

6.2.1.2.1 Functionality

It is recommended to test the control scheme with a digital simulator for closed-loop hardware in the loop (HiL). As with the open loop testing, there should be a clear set of scenarios which can be run in the simulator. The initial focus of the testing should be on functionality, to verify the ability of the control scheme to act in response to the power system. Therefore, it is only required to test using the hardware which performs the main functionality and can use simulated PMUs for example and ignore protocol conversions and expensive amplifiers. It should be noted that these tests are a key part of the development process as the outcome of the closed loop tests will likely inform design changes which will go into a deployed system. It is recommended to create a realistic set of test scenarios including cases where the scheme should act, should not act but also edge cases where required.

It is also recommended to record the outputs of both the real-time simulator and the control scheme as these can be used for commissioning testing.

6.2.1.2.2 Reliability

Once the functionality of the scheme is verified, further testing on the scheme can be done in the Hardware-in-the-loop environment to test non-functional elements such as data quality, reliability and performance (e.g. latency). In a laboratory environment, it is possible to create scenarios such as loss of data, or equipment failure to test the overall behaviour of the scheme in different failure modes. The specific tests will be informed by the final architecture, e.g. is redundancy required etc. These tests should include all equipment which is required for the appropriate test, e.g. if reliability is being tested, then redundant equipment is required, if latencies are being tested, a communication emulator would be required as well as any device performing protocol conversion.

6.2.1.2.3 Cybersecurity testing

It is recommended to perform an intrusion test on the final solution to identify any vulnerabilities in the system. The architecture for this test should include all equipment that is required to make the solution secure and may include equipment that is also to be installed in operator control rooms, such as key vaults etc. The set of tests will depend on the chosen architecture and level of security that has been agreed upon.

Upon completion of these tests, functionality, reliability and security testing will be completed in a laboratory environment with the system now ready for deployment. In order to minimise the risk during commissioning, it is recommended to consider the following testing during development:

- Localised field trials (testing ability of resources to accept control)
- Communications links (if different from communications links available in lab, e.g. 4G)

6.2.2 Commissioning

6.2.2.1 Factory acceptance testing (FAT)

It is recommended to perform a factory acceptance test of the scheme to be delivered. This can be done with a hardware real-time simulator (if available) or driven using simulated signals, or captures during the development phases. The purpose of the FAT is to ensure that all agreed functionality is working as expected and that each of the components-under-test are communicating with each other. It is not expected to include all elements of the scheme as resource controllers or the ADMS is outside of the scope, therefore it is recommended that some test tools are available in place of these components. The FAT serves as the last complete control solution test to demonstrate the full functionality of the scheme. Another purpose of the FAT is to sign off on the equipment which is to be installed as it is the same equipment that will be installed in the substations.

For subsequent additions or installations, a FAT is not always necessary however it is recommended that a more detailed set of tests are performed in the SAT of the additional equipment. For example, if a new site is identified for measurements, the device could be installed after limited testing and then more detailed tests carried out with the overall scheme.

6.2.2.2 Site acceptance testing (SAT)

It is likely that the SAT will be split into a number of different tests given that there are a number of locations involved to complete the solution, which includes a centralised controller, synchrophasors devices, protocol convertors etc. It is recommended that a SAT be completed for each unique site location to ensure that the installed equipment remains operational as verified by FAT. It is recommended that a SAT be completed for each of the following sites/components:

- Field sites where resources are located
- Field sites where PMUs only are located
- Central control scheme
- Control room (limited to interaction with the control scheme)
- Full scheme (testing of the full end to end solution within the SAT constraints)

As part of the SAT, equipment will be installed and configured to receive live measurements, therefore it is not intended to test the operation of the scheme during SAT. The outcome of the SAT is that each piece of equipment is sending/receiving live and valid data and is integrating with the other components of the system.

As part of the commissioning process, it may be possible to inject test signals prior to configuration to live measurements. This can involve a signal injector (e.g. Omicron) for measurement devices, PMU simulators for control devices. It is recommended to perform signal injection testing to ensure the correct signal chain has been configured for each site. The exact testing sequence and setup will depend on the site locations. In each test with an injected signal, the devices should not trigger any resource such as load banks or generation. This should be achieved through a "test mode" whereby an operator or commissioning engineer can place certain devices into a testing mode which will test functionality but allow the operator to supress any control action from taking place.

6.2.3 Regular checks during lifetime

6.2.3.1 Architecture

The architecture including the test signal injector and the behaviour of the devices is shown in Figure 29. The test signal injector is a substation PC which will require a connection to the control room operators in order to run the test scenarios.

Figure 30 shows the data layer for the test architecture.

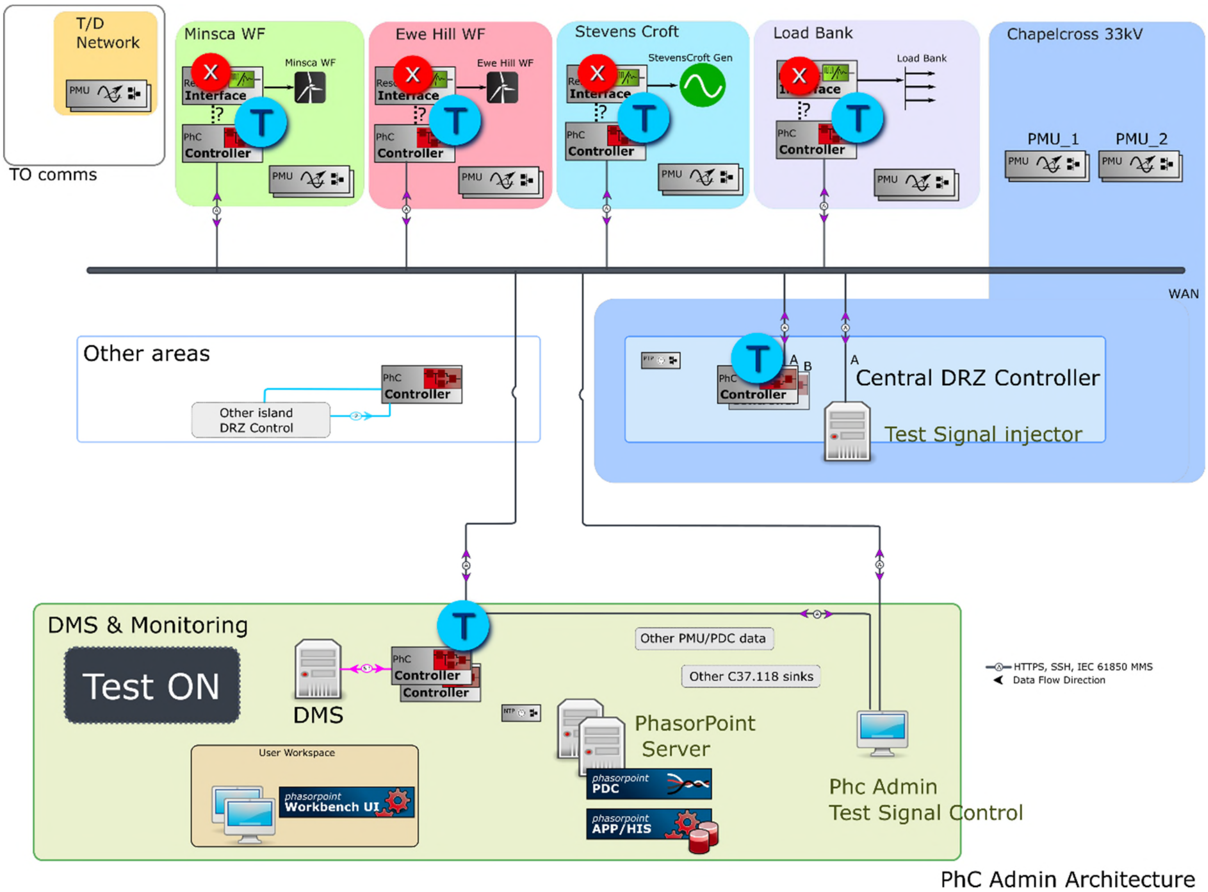


Figure 29 Administration layer for testing

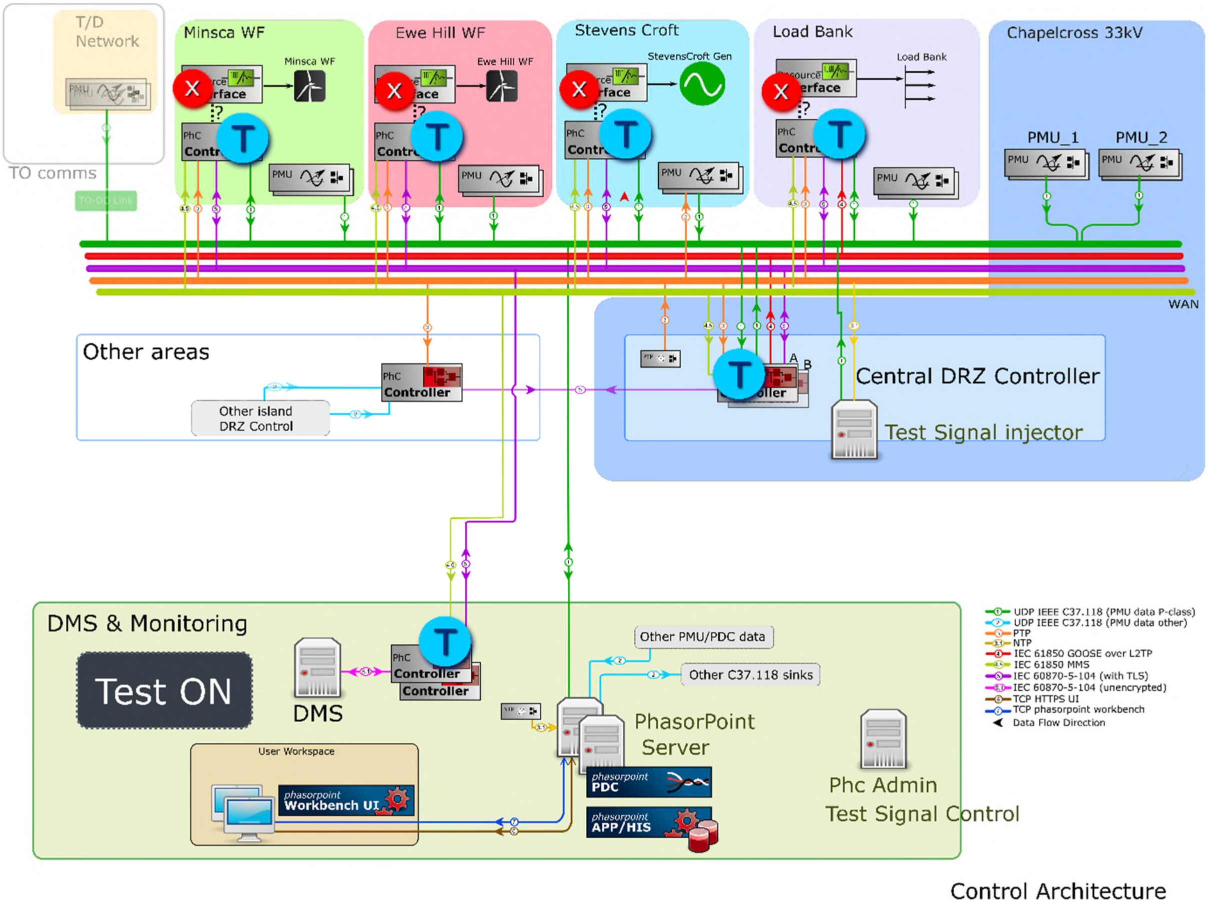


Figure 30 Data layer for testing, showing the IEEE C37.118 link from signal injector to WAN.

6.2.3.2 Deployed Scheme

The scheme should be tested regularly to ensure its availability if it is ever required. The description of regular testing assumes that there as an "A" and "B" system for redundancy, which also allows operators to test a scheme in stages without affecting the ability of the scheme to operator if required.

The regular testing of the scheme will utilise the IEC 61850 defined behaviour for "test mode" and will also include a signal injector to be located at the central control location.

6.2.3.2.1 Test Signal Injector

To test the functionality of the scheme, there must exist a method by which to inject data into the scheme which replicates an "operate" state. This can be achieved by installed a test signal injector at the site of the Central Controller. The test signal injector comprises a substation PC with a software playback tool which could produce a set of "emulated" PMU streams to the control scheme. The tester will have the ability to control the playback cases. There can exist a case library of outputs which can be the same used in the development and FAT processes. The playback of the cases will be controlled via a web interface to the substation PC.

6.2.3.2.2 Test Mode

It is recommended to make use of the IEC 61850 standard with reference to device and behaviour testing modes. This allows operators to place components and schemes into a specific mode for testing, but also to inject signals which are marked as test signals. In the scenario where an operator wishes to test the scheme using the signal injector, the outputs of the injector will be marked as “test” in their metadata. If the scheme is in healthy mode, the controllers will ignore such signals. However, if the scheme is placed in test mode, it can be configured such that only signals which are marked as “test” are used in the algorithms, thus allowing the user to simply switching sources for data. When the scheme is in test mode, it will be designed such that any tripping or control outputs are supressed, and are instead send as monitoring values so that an operator can confirm the behaviour without taking any control.

The behaviour while in test mode is summarised in Figure 31, where data marked as “test” from the signal injector is only consumed if the device or scheme is in “test”.

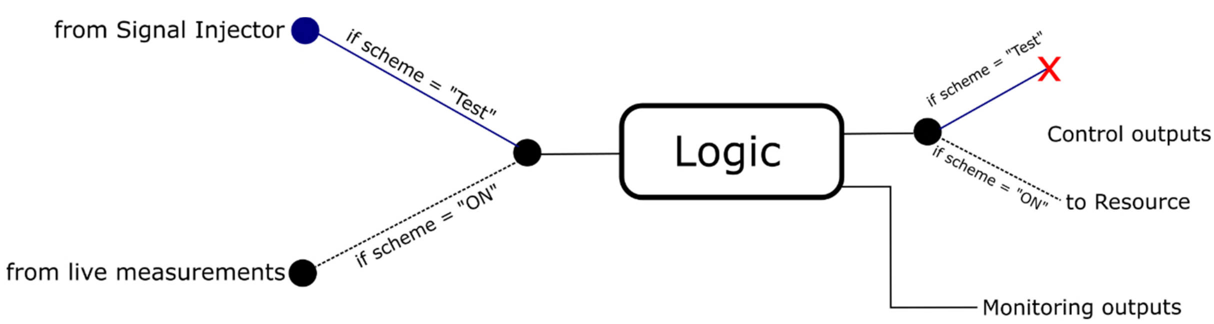


Figure 31 Test mode signals

6.2.3.3 Testing sequence

Testing should be carried out on each of the redundant systems one at a time. The following outlines the key steps in the test sequence:

1. Operator enables test	Operator places either system A or B into test mode via an IEC 60870-104 signal from the DMS or via MMS via the PhasorControllers in the control centre. This sends a test command down to each piece of equipment in the chain.
2. Operator starts signal injector	Start injecting data into the system under test from the injector device, accessed via a PC in the control centre.
3. Operator opens monitoring system	Have the monitoring system open and verify data is received from the devices under test.
4. Operator selects a test case on the signal injector and runs it	The signal injector contains a set of cases which can be played back, these can include different cases to test different scenarios or different functions

5. Observe the results in the monitoring application	No control actions should be initiated from the system under test, instead a control signal can be visualised in the monitoring application, but will not be sent to the resource. Operator to verify that correct action was taken.
6. Switch System A back to normal	Operator to remove the test mode on system A, this should automatically let it switch back to live measurements
7. Switch system B into test mode and repeat	Repeat the same tests on system B and verify behaviour.
8. Switch system B back to normal	Upon verification of both system A and System B, both systems should now be back to normal.

Table 14 Testing Sequence

6.2.3.4 Substation maintenance and new additions

For devices installed in substations, there should be the ability to place devices in test mode to prevent any unwanted tripping if the substation is under test. This applies to both measurement devices and control devices.

Where new additions are made to the scheme, either new measurement points or new control locations, a clear set of test criteria must be created. Ideally, where there are significant changes, a replica of the main controller would be recommended so that changes to the scheme can be made away from the live system. When changes have been verified, the updates should be rolled out to the system and tested using the signal injector. It is likely that data corresponding to the new changes will be required so that there is equivalent data in the test library. For example, if new measurement devices are added, there should be a new equivalent data stream from the signal injector. When the additions have been completed to the case files, the system should be tested based on test sequence for regular checks. If a replica system is available, the test cases that were used to test that system can be migrated over to the signal injector.

6.3 Training requirements

6.3.1 DRZC Controller Training

DRZC training is designed for staff involved with the deployment, testing and operation of the DRZC controller, and will cover the following areas:

- Control Scheme architecture
- Control Scheme operation
- Training on the use of the GE PhasorController platform

The purpose of this training is to provide an introduction on how the DRZC scheme will operate and how it is implemented on the controller. The training shall use, as a training tool, a generic power system and may not be customised to the SPEN distribution systems.

6.3.2 WAMS Training

WAMS training is designed for staff who are involved in monitoring and analysis of the DRZC scheme, and will cover the following areas:

- Control scheme supervision through WAMS
- Auditing system and DER response
- Training on the use of the GE PhasorPoint platform

The purpose of this training is to provide an introduction on how the DRZC scheme will interface to the WAMS.

6.3.3 PMU Training

A PMU training course will be run by the vendor and should be designed for staff who operate and maintain the measurement systems, as well as staff who use PMU measurements for analysis. The training course should cover all aspects of the PMU installation and operation. GE recommend the DR60 product for synchrophasor measurement.

7 Bibliography

[1] GE, "Distributed ReStart Deliverable 2: DRZC Communications Requirements Report".

[2] GE, "Distributed ReStart Deliverable 3: DRZC System Integration Requirements Report".

[3] ENA, "https://www.energynetworks.org/assets/files/ENA_EREC_-G99_NI_Issue_1_April_2019.pdf (Table10.1 Settings for Long-Term Parallel Operation, p89)".

[4] SPEN, "Distributed ReStart - Revision to Appendix 2,3 and 4 of ITT.pdf".

[5] "Smart Grid ROCOF project, http://www.RoCoFmetrology.eu/ accessed 15/6/2020, EMPIR programme and EU Horizon 2020 funded".

[6] SPEN, "CHAP Restoration Strategies 16_1_2020.xls".

8 Appendices

Appendix A: Cost Breakdown

The aim of this section is to provide the DNO utility with a guideline implementation cost, including a breakdown into individual components and incremental cost of expanding the system beyond the initial installation.

The following assumptions are made in order to simplify the costing exercise and the subsequent usage of the guideline cost figures:

1. Investments into the primary substation equipment (generators and transformers), as well as certain secondary systems (for example ensuring the availability of resilient power supply for 72 hours and beyond) are not accounted for. Calculating the cost of such investments remains responsibility of the DNO.
2. The cost of upgrading the DNO communication infrastructure to meet the Distributed ReStart requirements is not accounted for.
3. The present costing exercise is focused on the business as usual (BaU) roll-out of the proposed solution in the UK DNOs. It is therefore assumed that by the time of the BaU roll-out the Distributed ReStart solution would have already been fully developed and tested through other funding mechanisms. The cost of developing and testing of the required applications and features is not included in the analysis below.
4. The initial roll-out cost is provided for the smallest viable solution that can be implemented while maintaining all key functions described in Section 5. It will consist of the following components:
    a. DNO Control Centre part with ADMS, Monitoring and Configuration tools
    b. Central DRZ Controller substation (e.g. Chapelcross 33kV)
    c. Anchor Generator (e.g. Stevens Croft generator)
    d. Load Bank
    e. A single windfarm location used for Slow Balancing.
5. Subsequent additions of Fast or Slow Balancing resources to the Distributed ReStart Zone are provided as an incremental cost per resource.

The following table presents the cost breakdown for the initial Distributed ReStart package:

Component	Cost, £k	Included equipment or services
DNO Control Centre	261	See below
Hardware	82	HW for PhasorPoint x1, HW for Crypto Key Vaults x3, PhasorController PhC213 x2, Switches x2, Cables and Accessories, Rack x1, Warranty for HW
Software Licenses	54	PhasorPoint SW license x1, PhasorController Designer licenses x5
On-site labour cost	95	Deployment and configuration of PhasorPoint and PhasorControllers, Integration with ADMS (using IEC 60870-104 or IEC 61850 MMS), ADMS configuration and new screens, Training (PhasorPoint, PhasorController, overall solution)
HW Installation	30	Cost of installation by a third-party contractor. This is a high-level assumption; the actual cost needs to be confirmed by the DNO with their selected installers.
Central DRZ Controller SS	245	See below
Hardware	94	PhasorController PhC214 x2, DR60 PMUs x4, Switches x2, Cables and Accessories, Warranty for HW

Cabinets x3	30	Assumed based on 3 cabinets £10k each. The actual number of cabinets and their price needs to be confirmed during the design stage.
On-site labour cost	31	Deployment and configuration of PhasorControllers and PMUs, equipment commissioning. The cost of third-party contractors is not included.
Cabinet installation x3	90	Cost of installation by a third-party contractor. This is a high-level assumption; the actual cost needs to be confirmed by the DNO with their selected installers.
Anchor Generator	128	See below
Hardware	57	PhasorController PhC213 x2, DR60 PMUs x2, Switches x2, Cables and Accessories, Warranty for HW
Cabinet x1	10	Assumed based on 1 cabinet at £10k, to be confirmed during the design stage.
On-site labour cost	31	Deployment and configuration of PhasorControllers and PMUs, interfacing with the resource, equipment commissioning. The cost of third-party contractors is not included.
Cabinet installation x1	30	Assumed cost of installation by a third-party contractor
Load Bank	128	See below
Hardware	57	PhasorController PhC213 x2, DR60 PMUs x2, Switches x2, Cables and Accessories, Warranty for HW
Cabinet x1	10	Assumed based on 1 cabinet at £10k, to be confirmed during the design stage.
On-site labour cost	31	Deployment and configuration of PhasorControllers and PMUs, interfacing with the resource, equipment commissioning. The cost of third-party contractors is not included.
Cabinet installation x1	30	Assumed cost of installation by a third-party contractor
Windfarm	116	See below
Hardware	45	PhasorController PhC212 x2, DR60 PMUs x2, Switches x2, Cables and Accessories, Warranty for HW
Cabinet x1	10	Assumed based on 1 cabinet at £10k, to be confirmed during the design stage
On-site labour cost	31	Deployment and configuration of PhasorControllers and PMUs, interfacing with the resource, equipment commissioning. The cost of third-party contractors is not included.
Cabinet installation x1	30	Assumed cost of installation by a third-party contractor
Other labour cost	160	Type registration/homologation of new equipment types, FAT and SAT of the integrated solution (all components linked together), project documentation.
Spares	67	PhasorController PhC214 x2, DR60 x2, Switches x2.
TOTAL	1105	

Table 15 Cost breakdown of the initial proposed Distributed ReStart package

To summarize, the estimated cost of the proposed smallest viable Distributed ReStart package is £1.1m.

It also allows utilities to assess the cost of scaled-up schemes. For example, if the initial package includes not one but three windfarms, then the cost will become 1105 + 2*116 = £1337k.

The subsequent additions of Fast or Slow Balancing resources to the initial package can be estimated at £150-160k per each resource. This figure is based on the cost provided above for different types of resources (i.e. £116-128k) with an approx. £30k added to fund the partial re-testing of the integrated solution, see Section 0 "Table 14 Testing Sequence

Substation maintenance and new additions".

In addition to the core scope of the proposed control solution, the following options (Table 16) are recommended by GE:

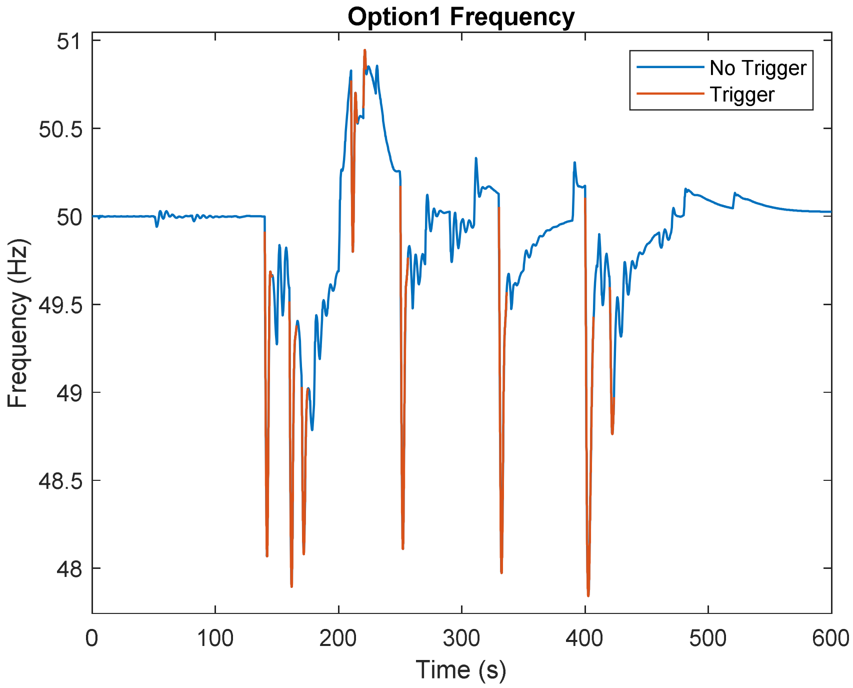
Component	Cost, £k
Replica/preproduction system (a representative copy of the deployed production system, to be used for testing and validation purposes)	540
Baselining and data analysis reports	
- one-off after 6 months of initial data collection	40
- periodic every month for 1 year	60
• T&M pool for control scheme amendments, covering 2 years support	120

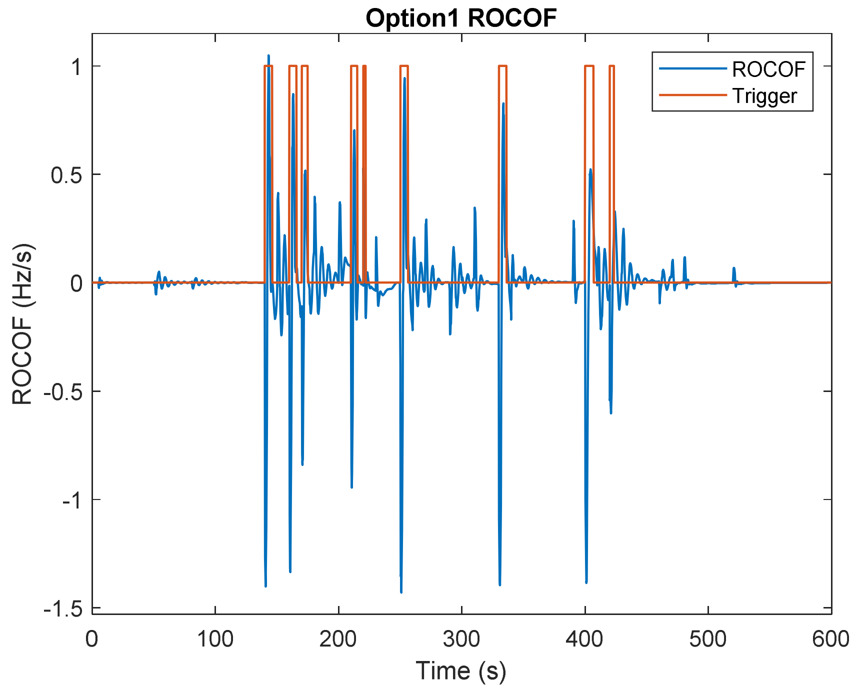
Table 16 Recommended options

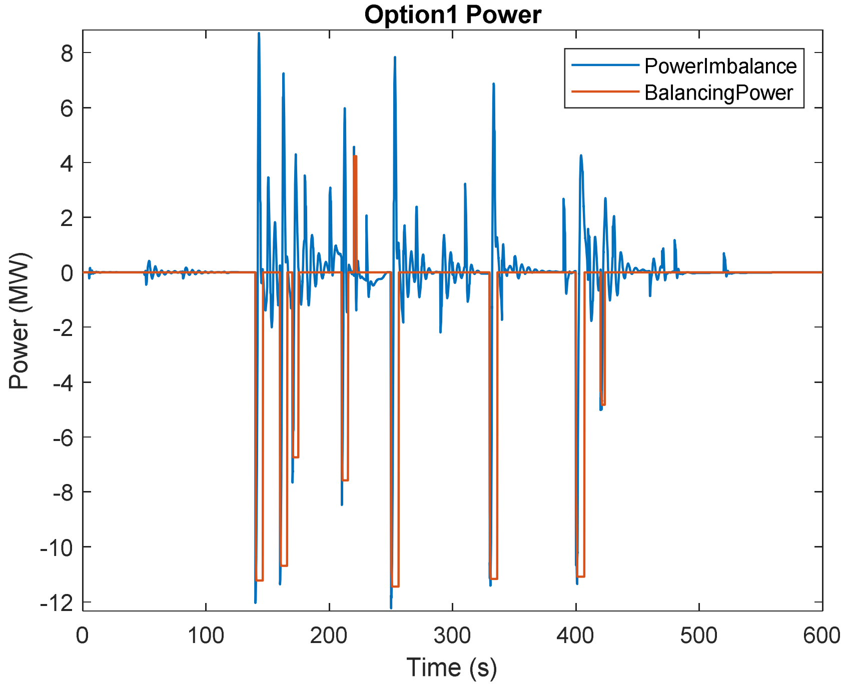
Appendix B: Fast Balancing test results

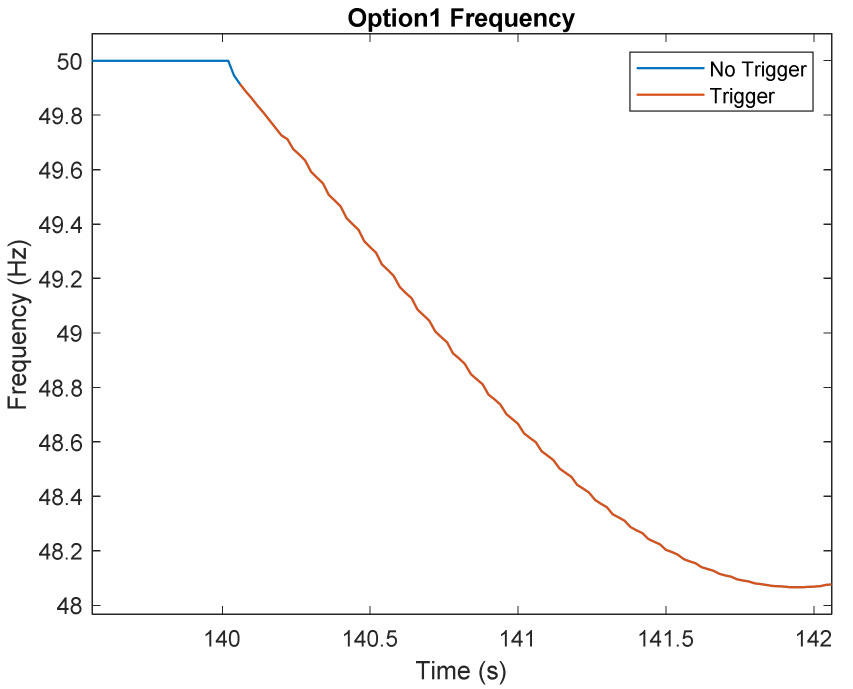
This appendix contains all 6 test cases from Section 5.3.7 which covered a range of restoration options. The plots show the entire 600 seconds for each test as well as a detailed view of each event that leads to a trigger.

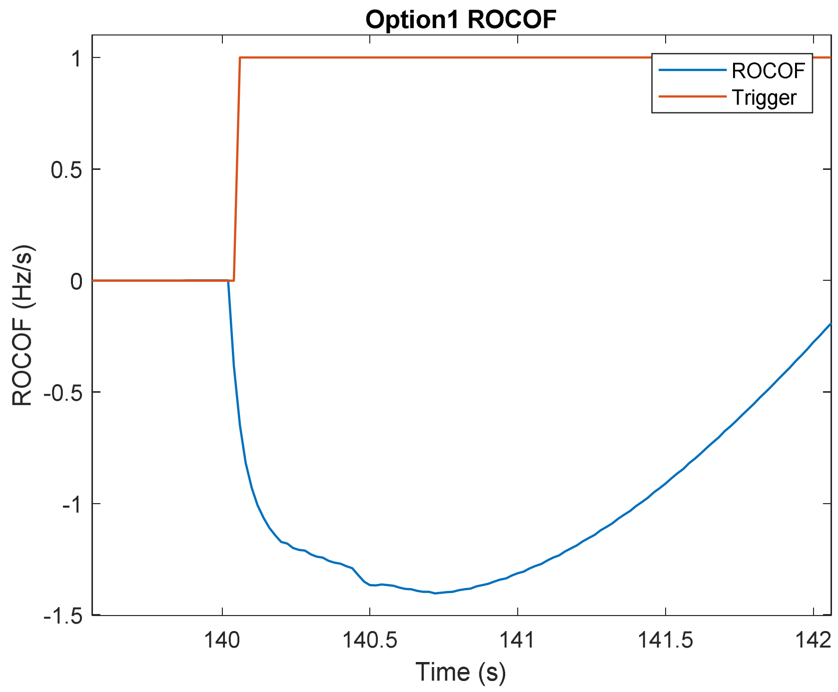
B.1.1 Restoration Option 1

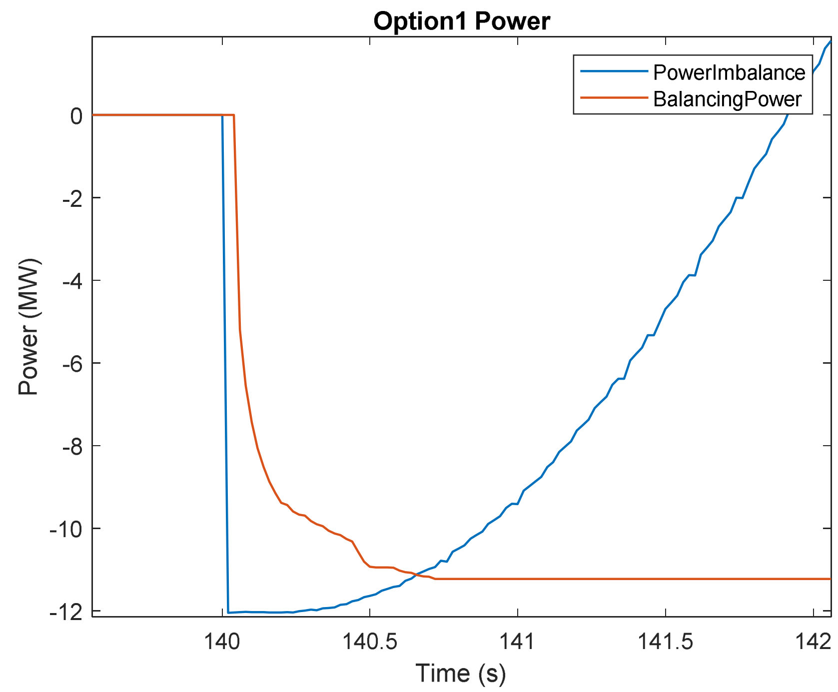


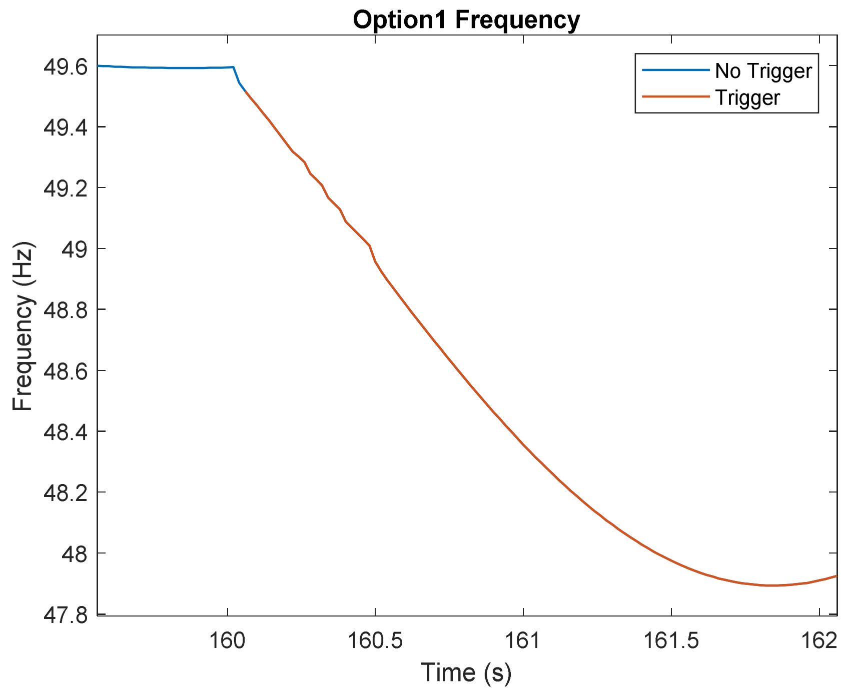


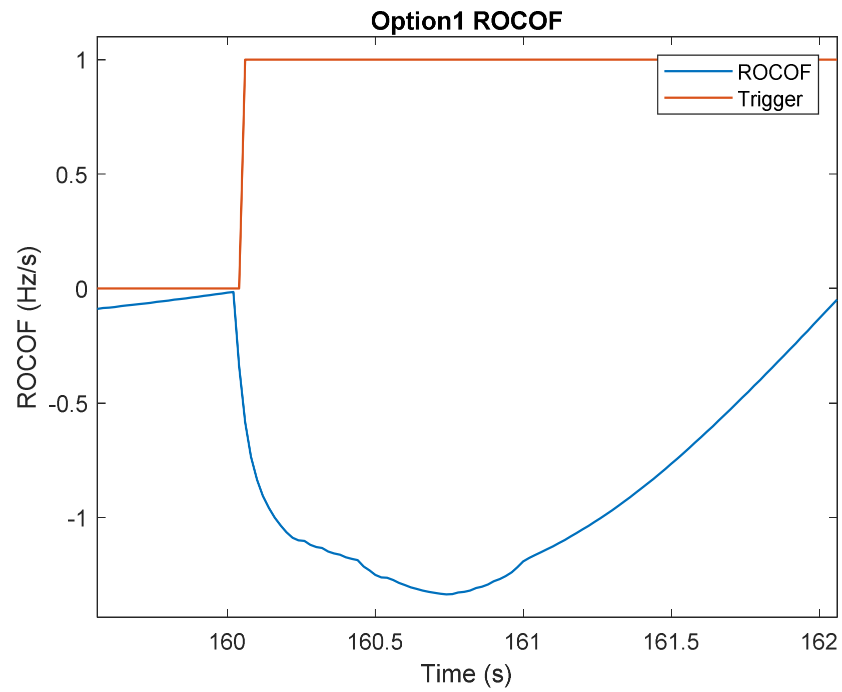

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
8
6
4
2
0
-2
-4
-6
-8
-10
-12
0
100
200
300
400
500
600

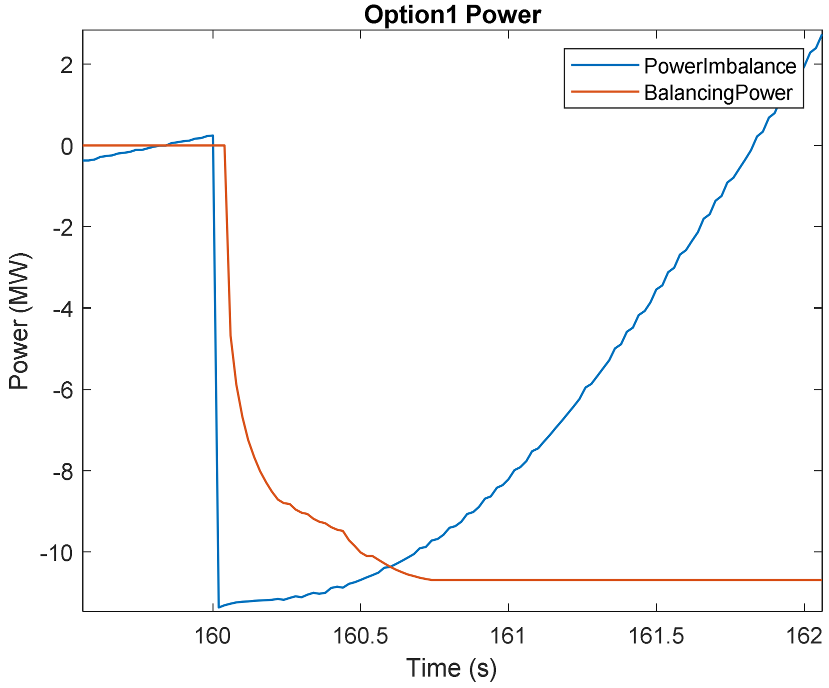

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
140
140.5
141
141.5
142

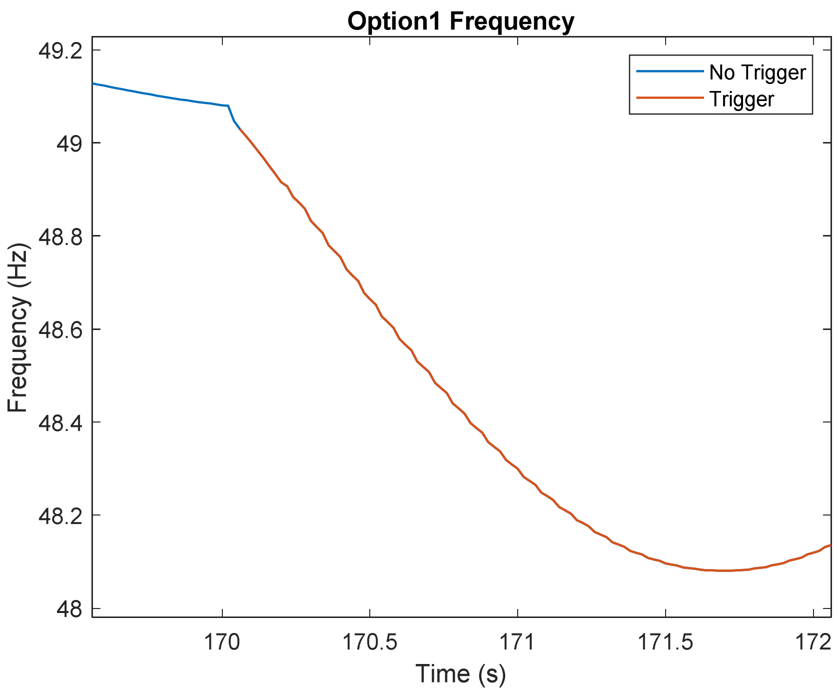

Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
140
140.5
141
141.5
142
Time (s)

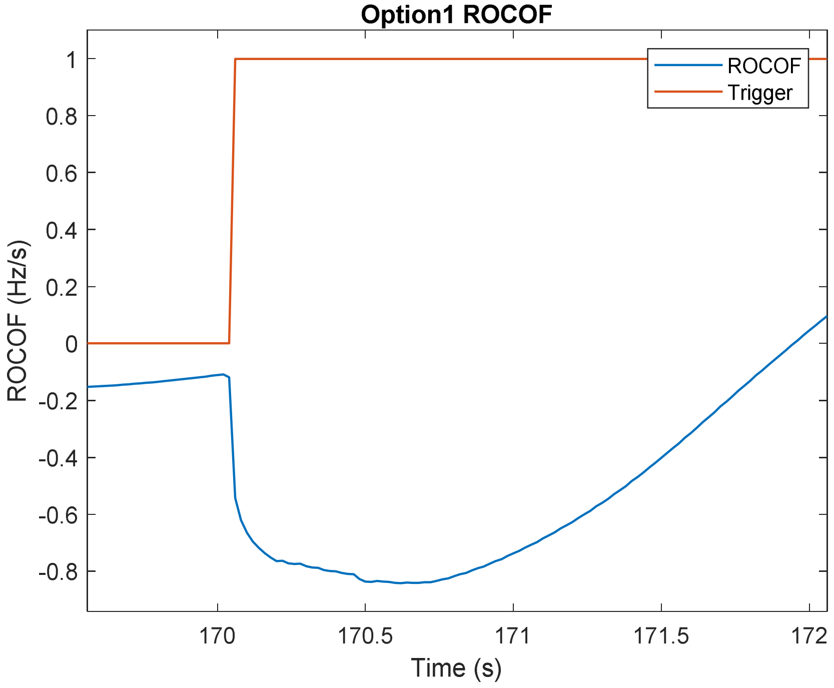

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
140
140.5
141
141.5
142
Time (s)

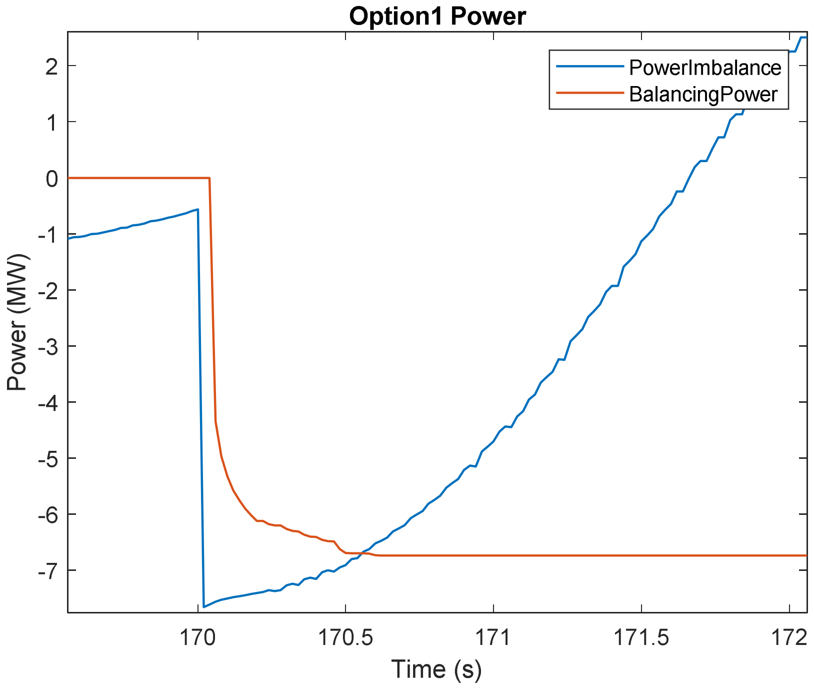

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
47.8
160
160.5
161
161.5
162
Time (s)

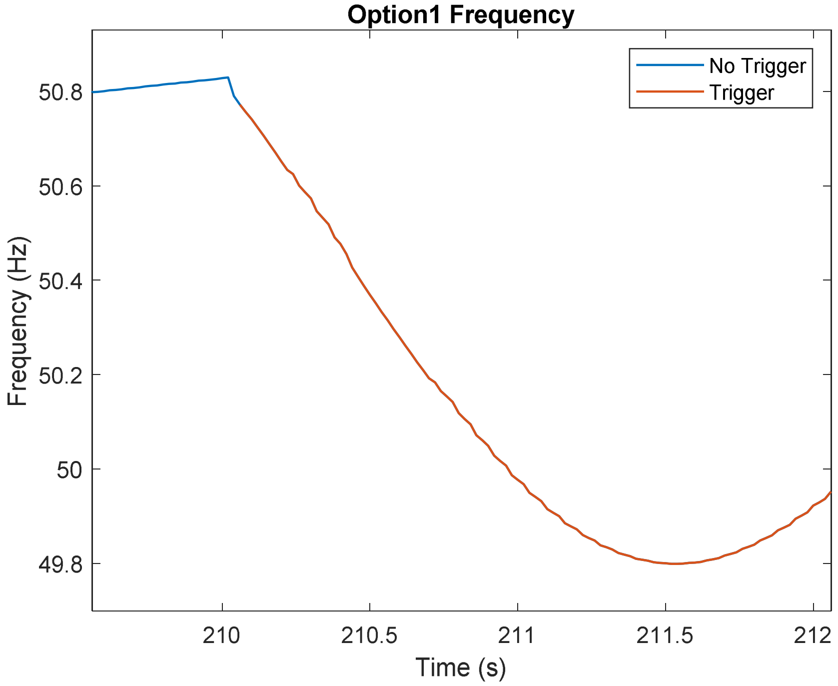

Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
160
160.5
161
161.5
162
Time (s)

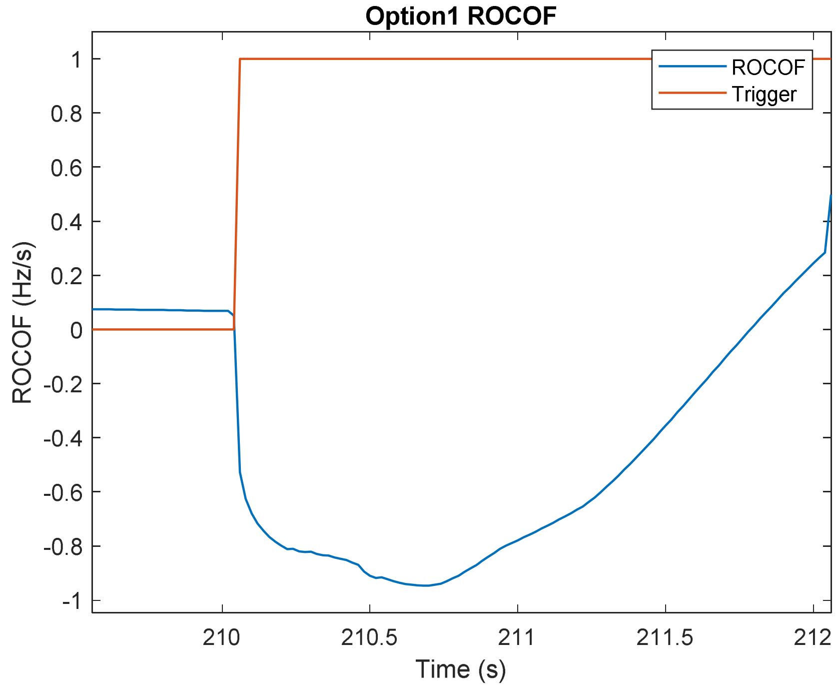

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162

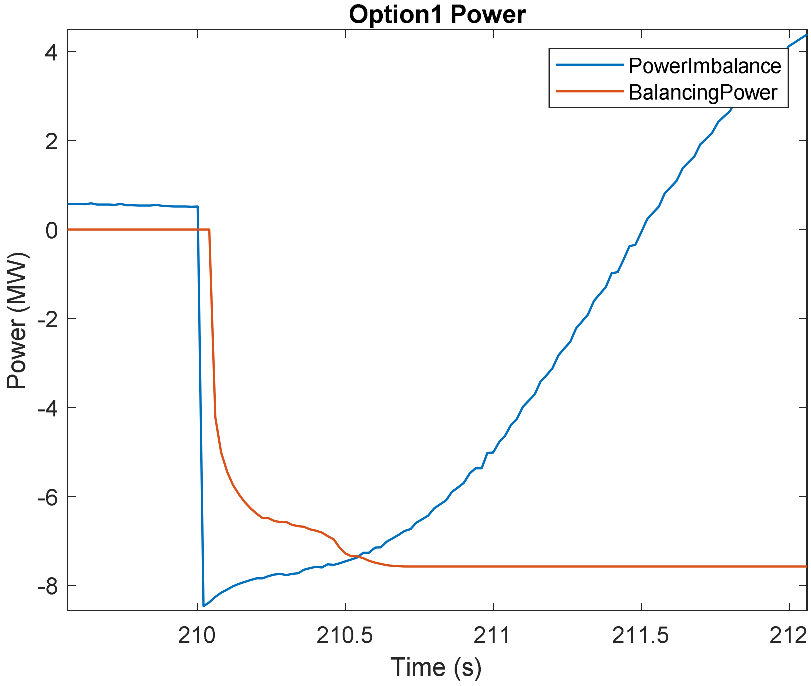

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
49.2
49
48.8
48.6
48.4
48.2
48
170
170.5
171
171.5
172

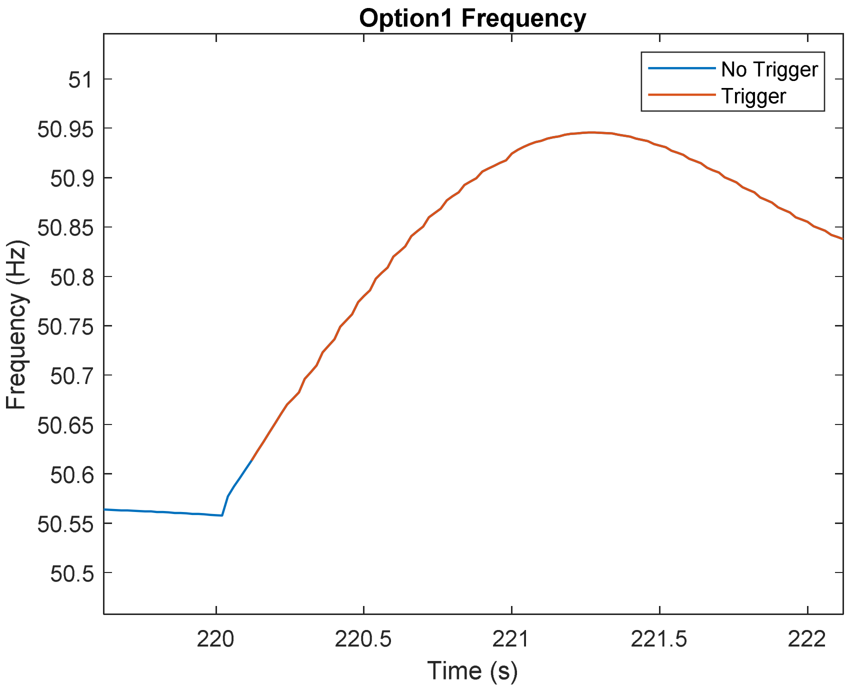

Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
170
170.5
171
171.5
172
Time (s)

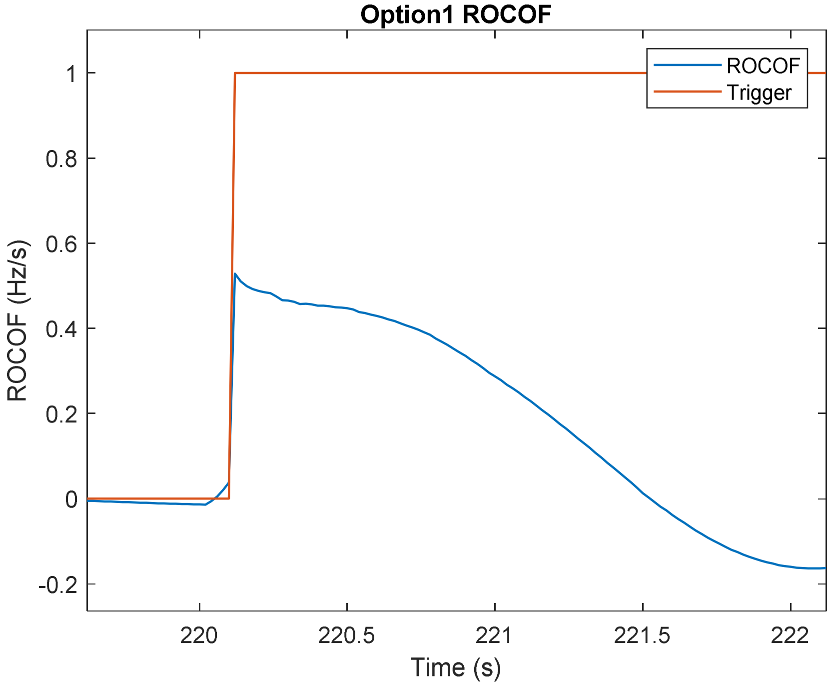

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
2
1
0
-1
-2
-3
-4
-5
-6
-7
170
170.5
171
171.5
172
Time (s)

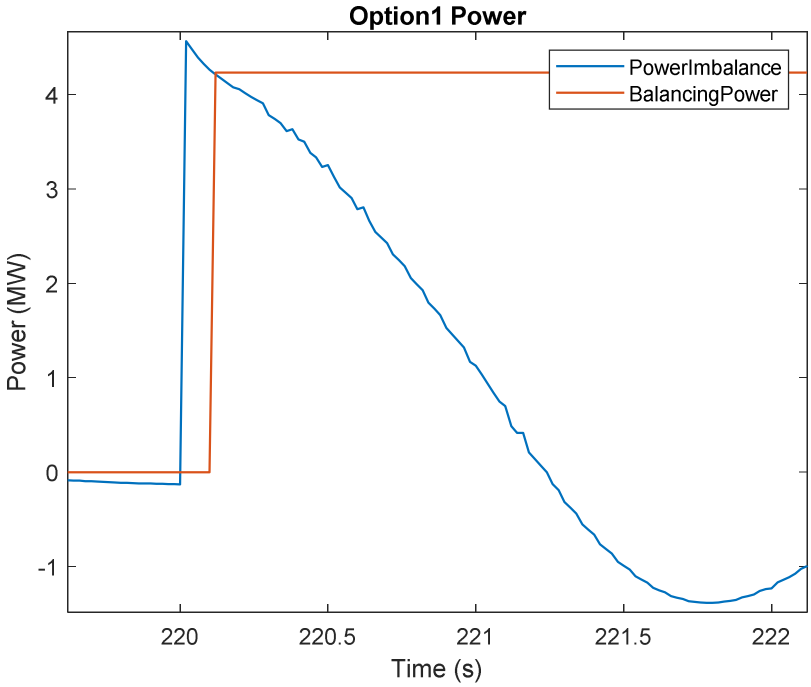

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
50.8
50.6
50.4
50.2
50
49.8
210
210.5
211
211.5
212
Time (s)

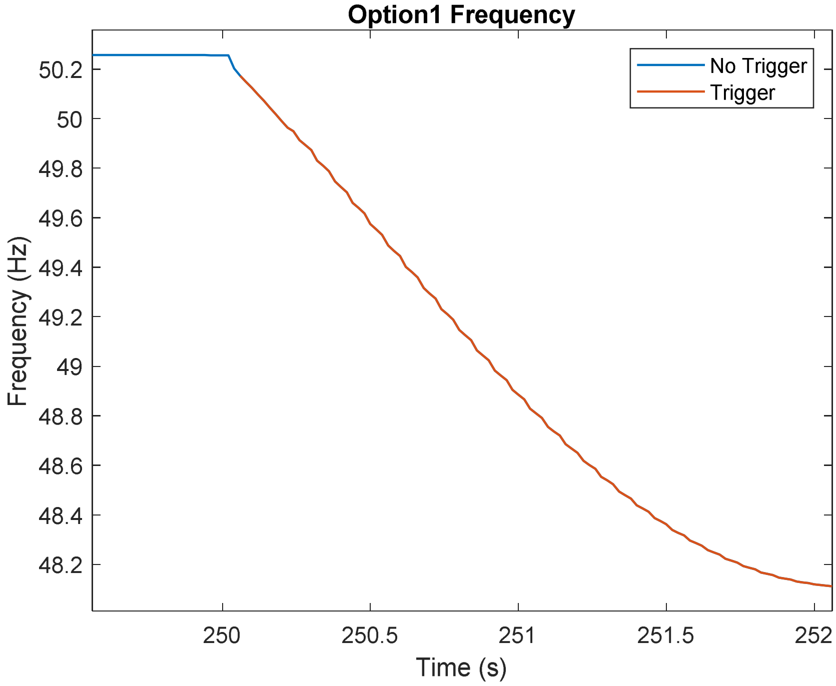

Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
210
210.5
211
211.5
212
Time (s)

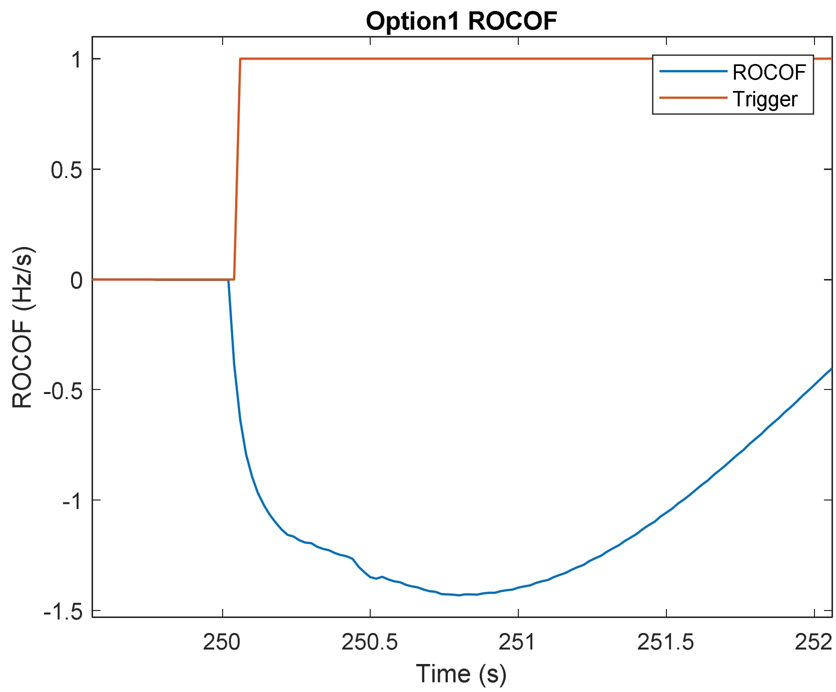

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
4
2
0
-2
-4
-6
-8
210
210.5
211
211.5
212
Time (s)


Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.95
50.9
50.85
50.8
50.75
50.7
50.65
50.6
50.55
50.5
220
220.5
221
221.5
222
Time (s)


Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222
Time (s)


Option1 Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
220
220.5
221
221.5
222
Time (s)


Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
50.2
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
250
250.5
251
251.5
252
Time (s)


Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
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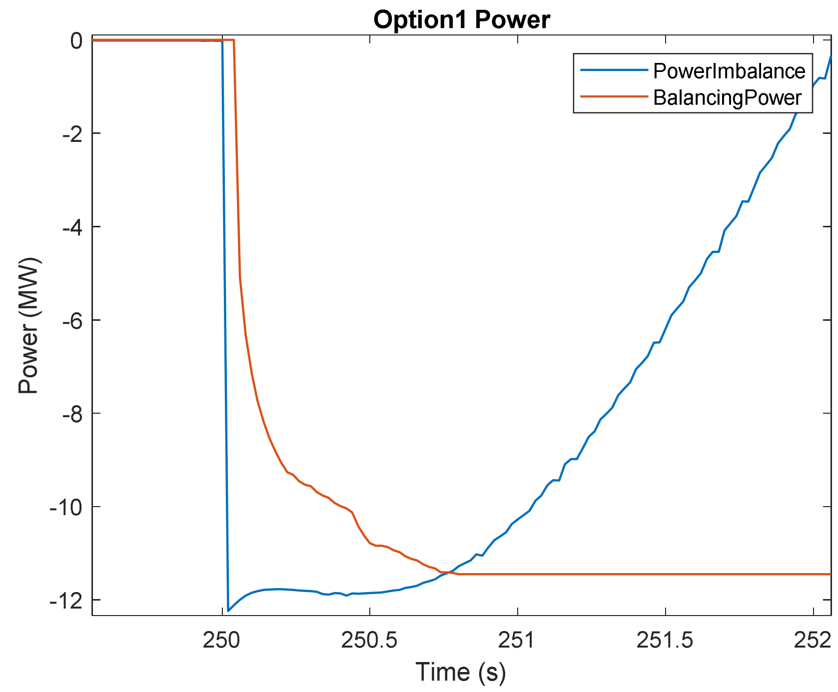
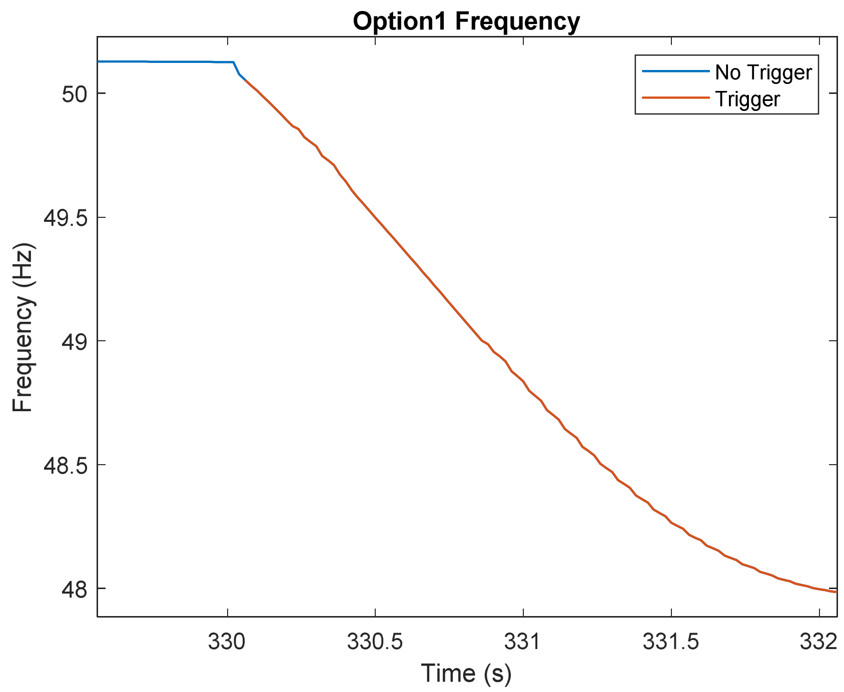
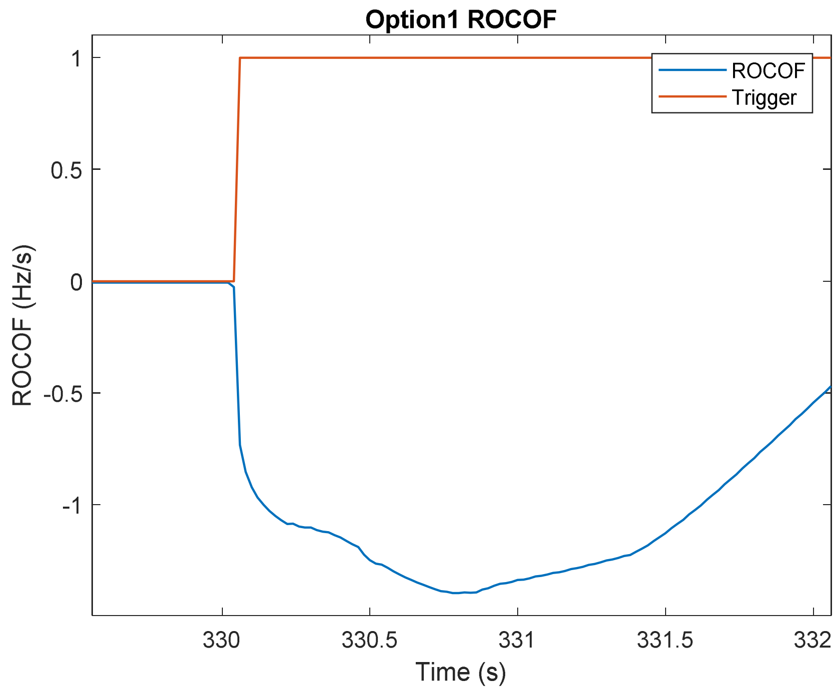
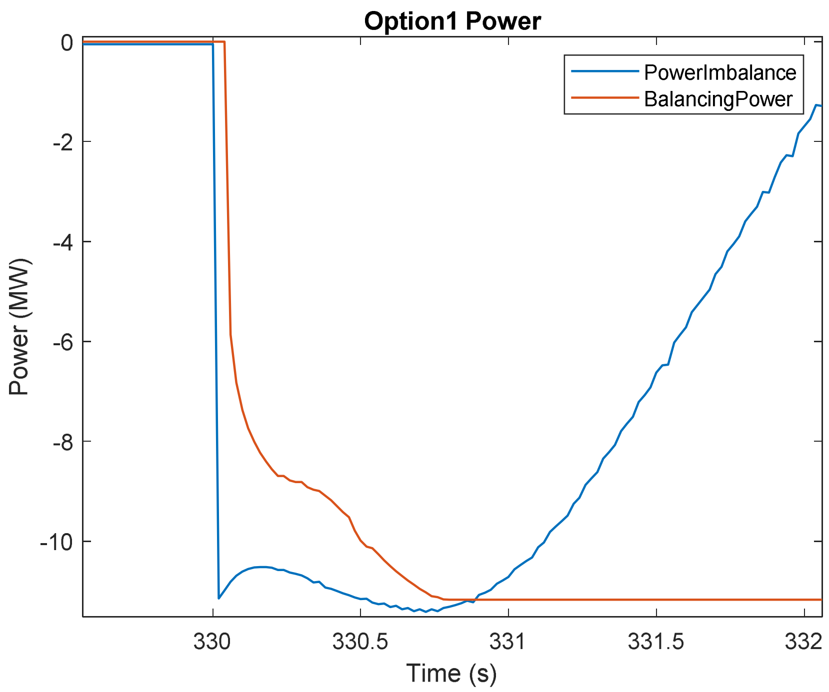
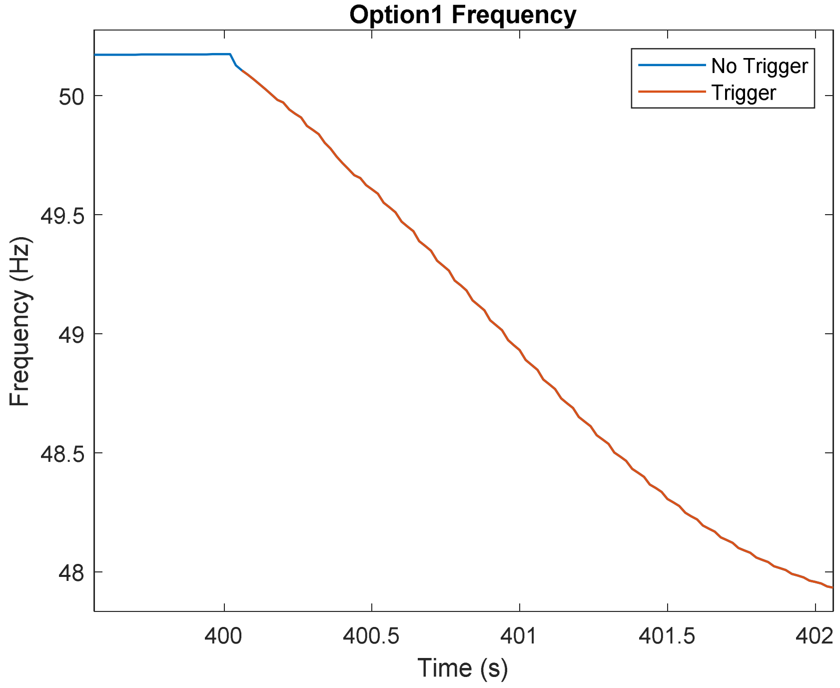
0.5
0
-0.5
-1
-1.5
250
250.5
251
251.5
252
Time (s)

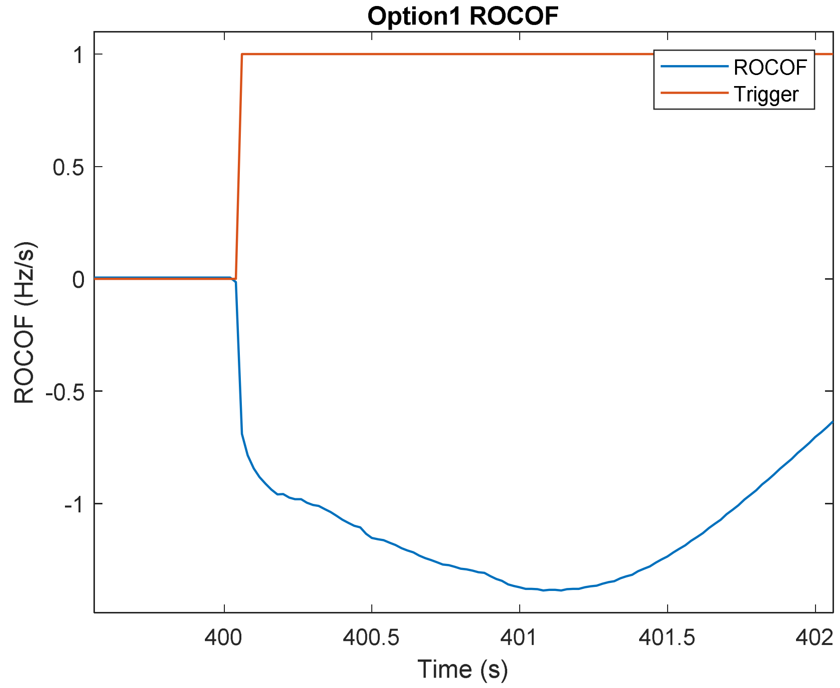

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
250
250.5
251
251.5
252
Time (s)

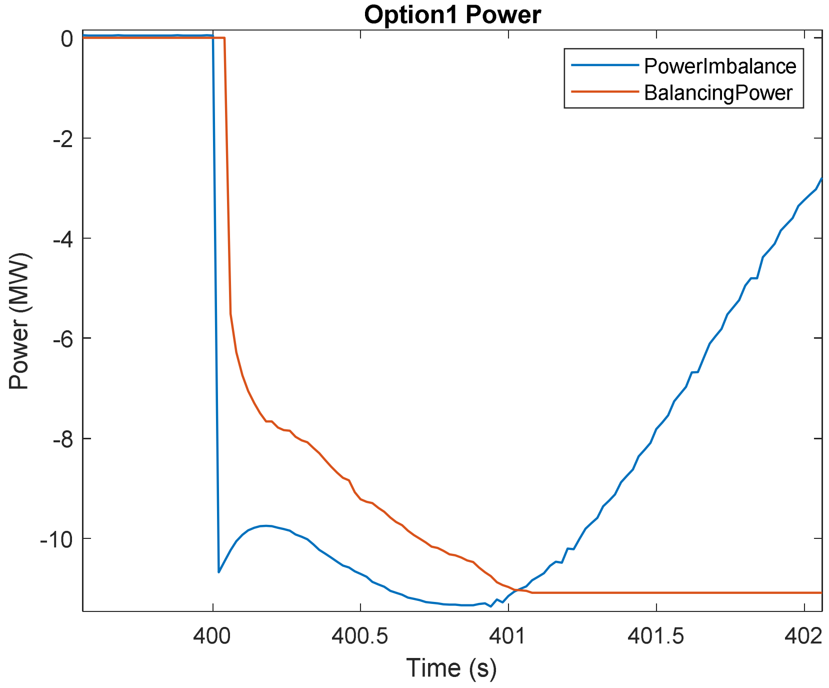

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
330
330.5
331
331.5
332
Time (s)

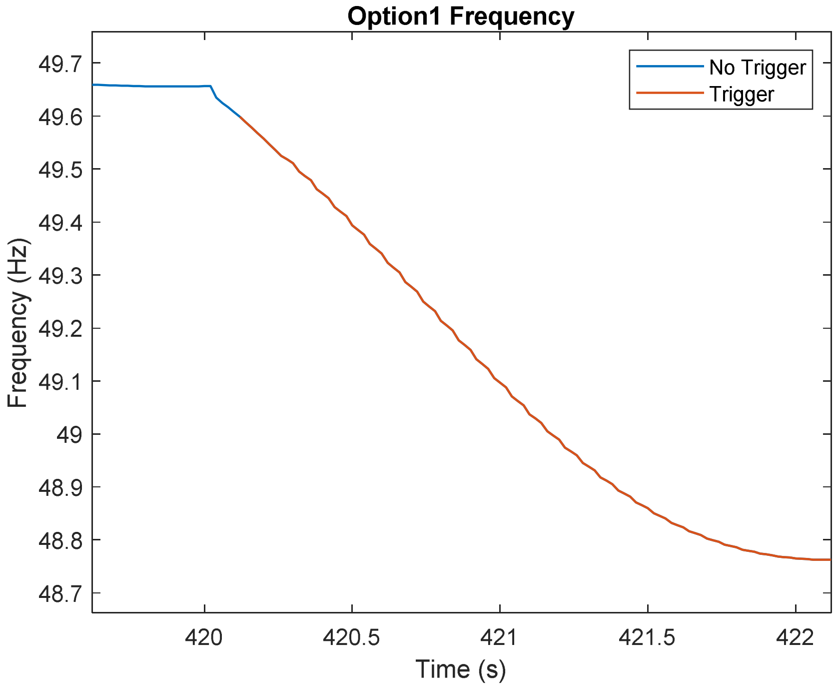

Option1 ROCOF
ROCOF (Hz/s)
Time (s)
ROCOF
Trigger
1
0.5
0
-0.5
-1
330
330.5
331
331.5
332

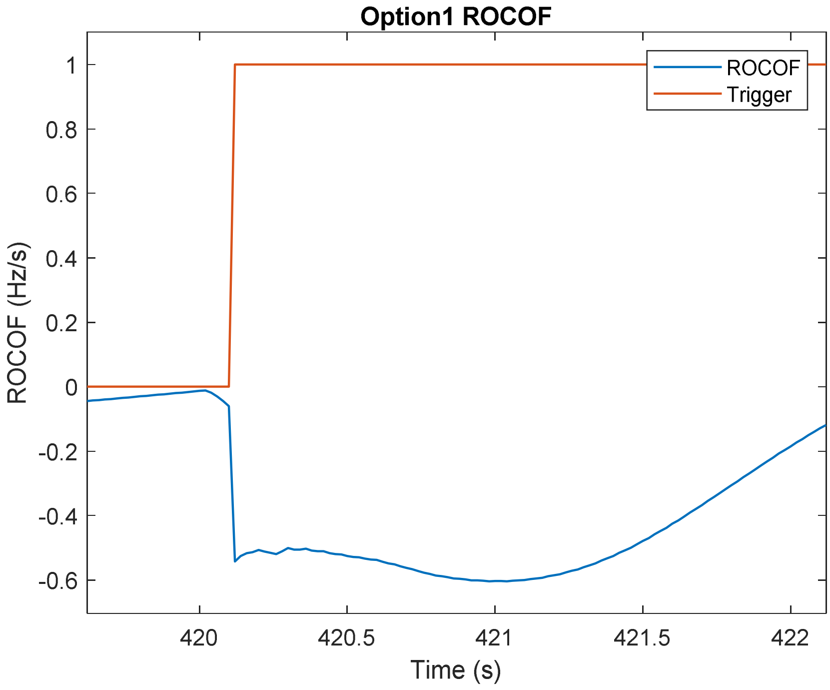

Option1 Power
Power (MW)
Time (s)
PowerImbalance
BalancingPower
0
-2
-4
-6
-8
-10
330
330.5
331
331.5
332

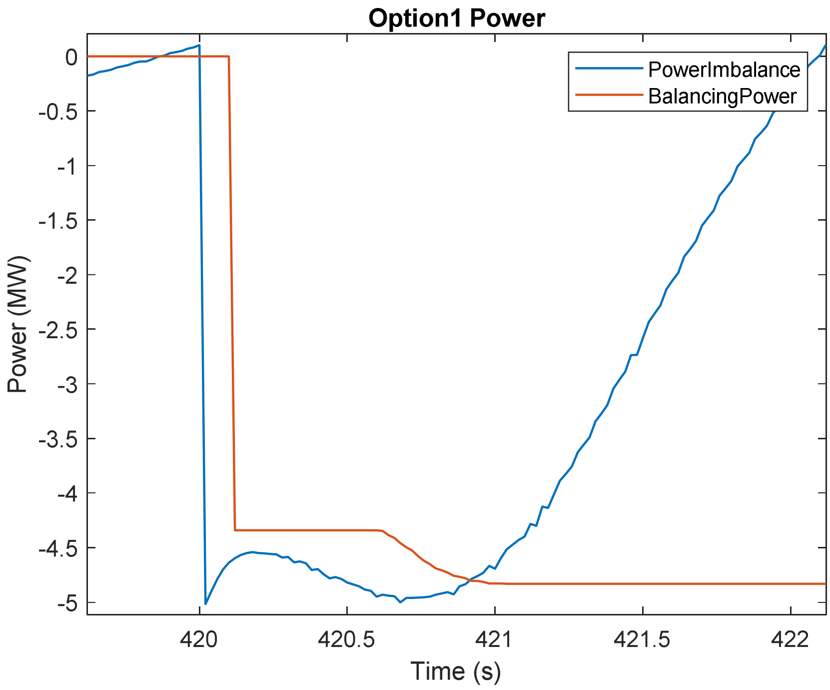

Option1 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
400
400.5
401
401.5
402
Time (s)


Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
400
400.5
401
401.5
402
Time (s)

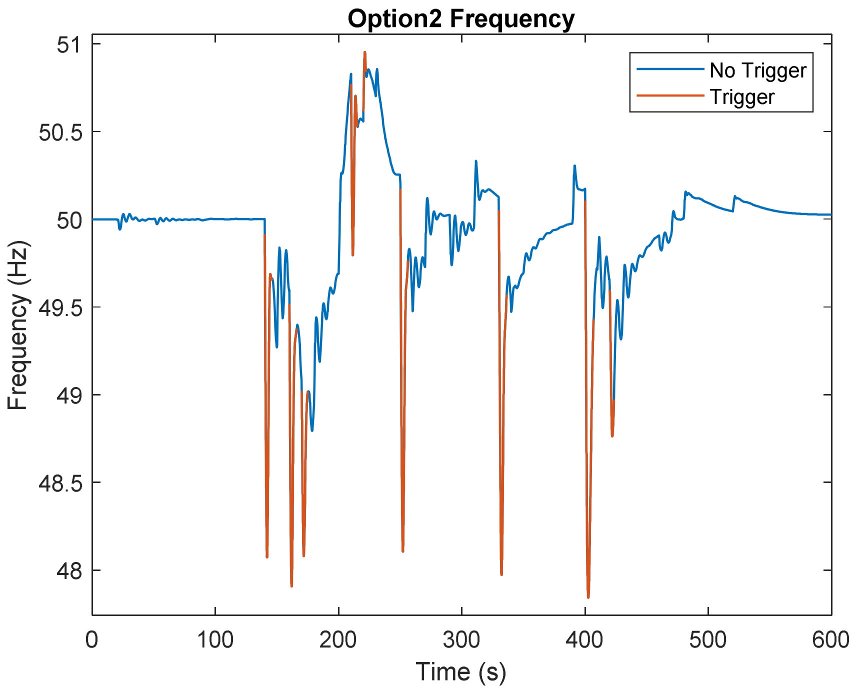

Option1 Power
Power (MW)
0
-2
-4
-6
-8
-10
400
400.5
401
401.5
402
Time (s)
PowerImbalance
BalancingPower

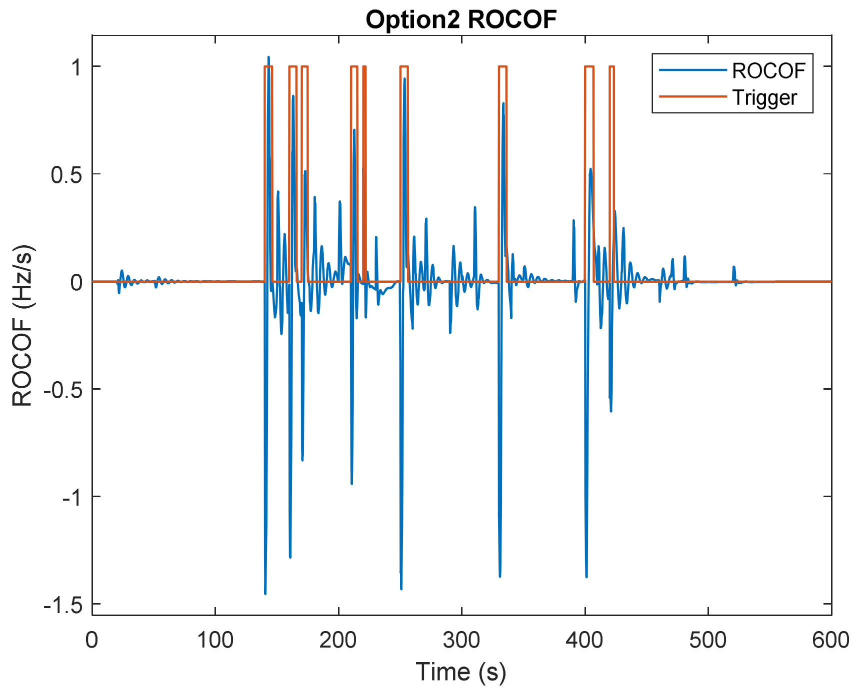

Option1 Frequency
Frequency (Hz)
49.7
49.6
49.5
49.4
49.3
49.2
49.1
49
48.9
48.8
48.7
420
420.5
421
421.5
422
Time (s)
No Trigger
Trigger

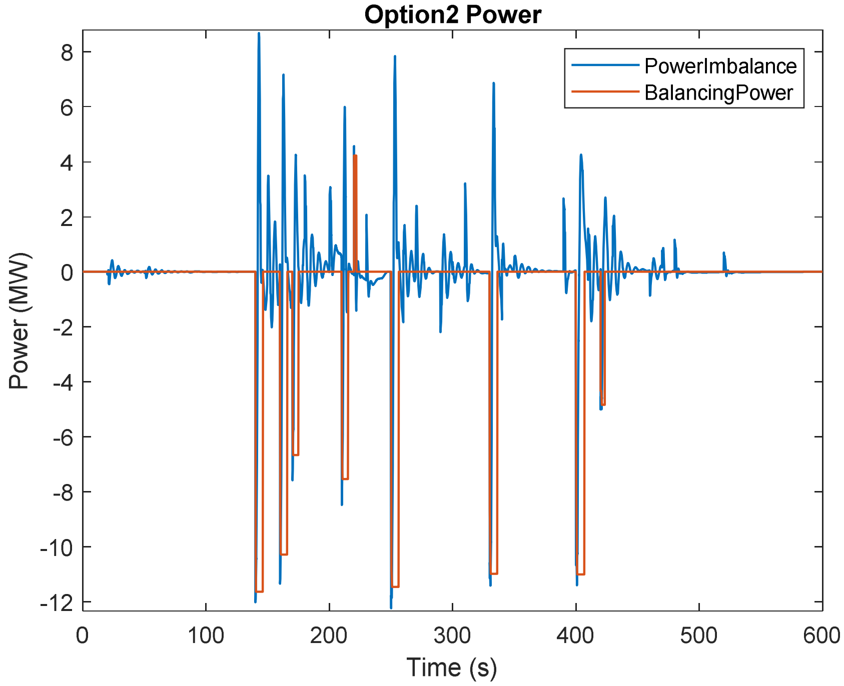

Option1 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
420
420.5
421
421.5
422
Time (s)

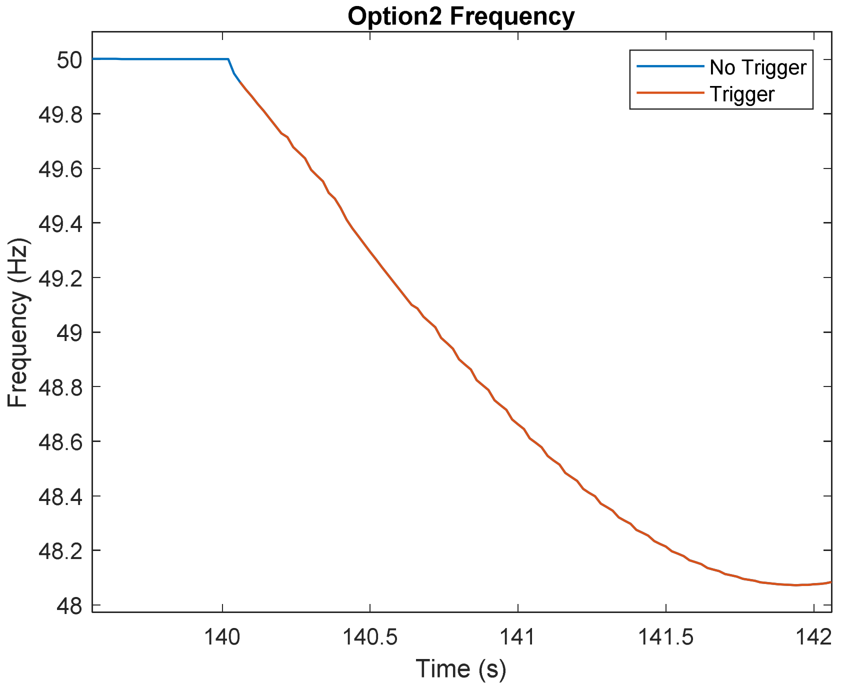

Option1 Power
PowerImbalance
BalancingPower
Power (MW)
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
-5
420
420.5
421
421.5
422
Time (s)

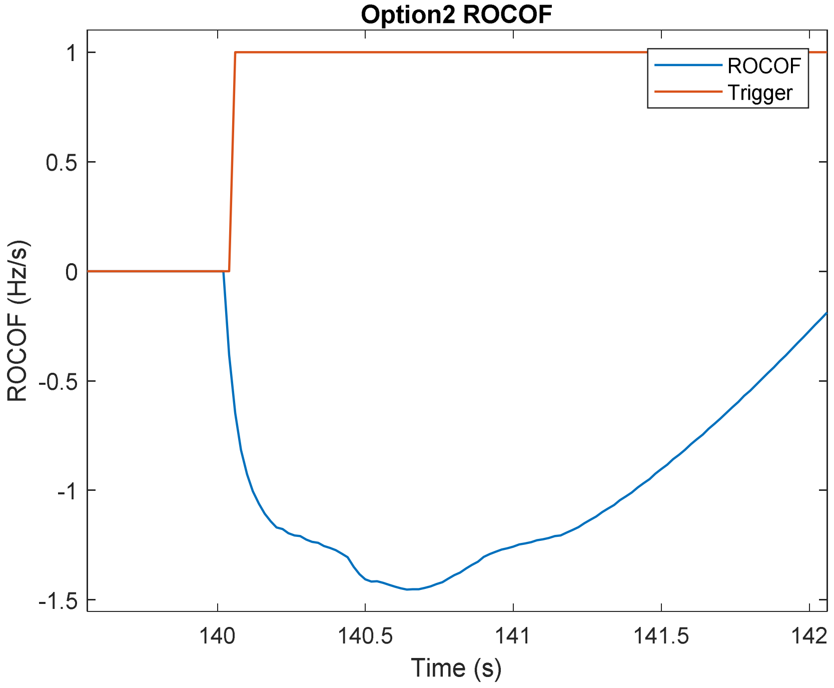
B.1.2 Restoration Option 2

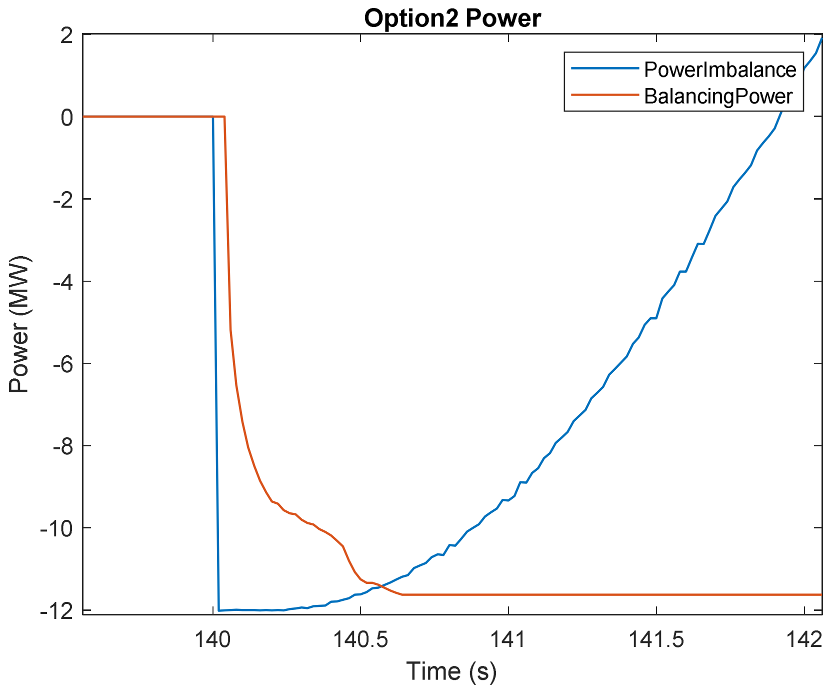


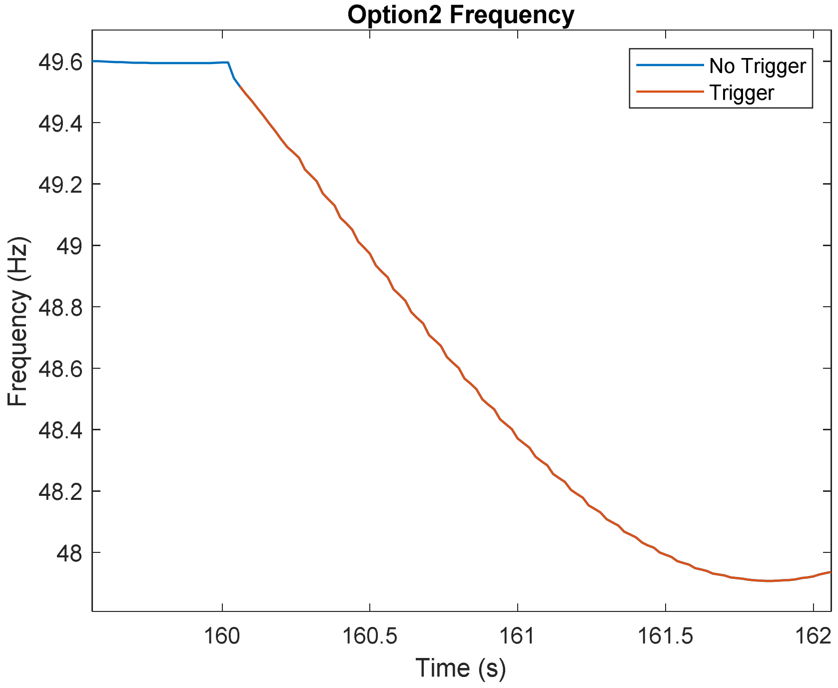


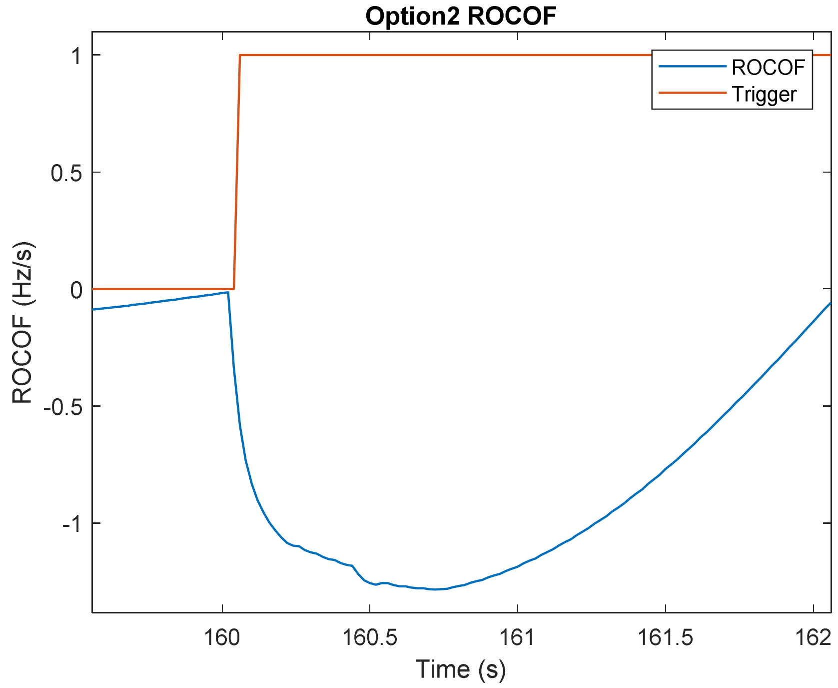

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
8
6
4
2
0
-2
-4
-6
-8
-10
-12
0
100
200
300
400
500
600

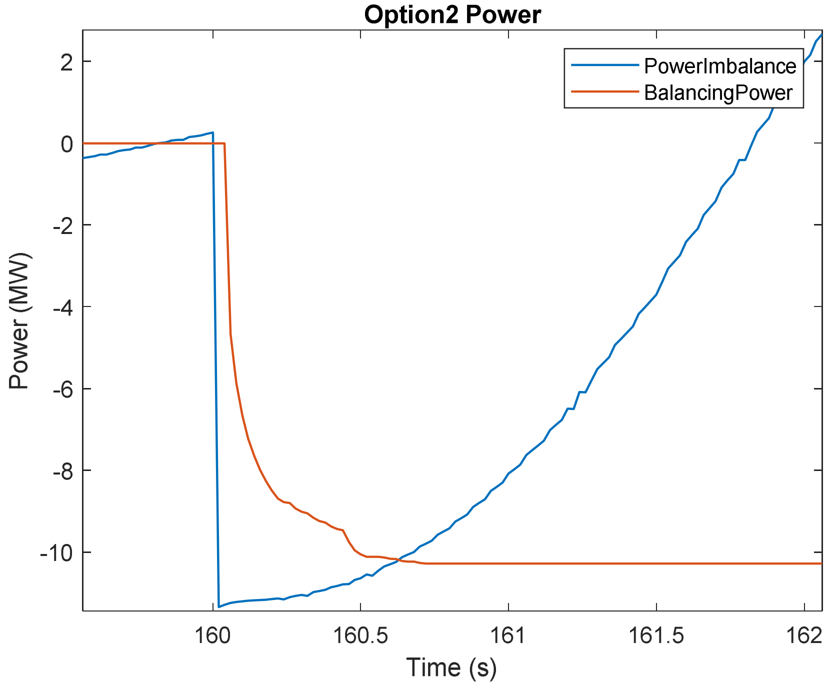

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
140
140.5
141
141.5
142

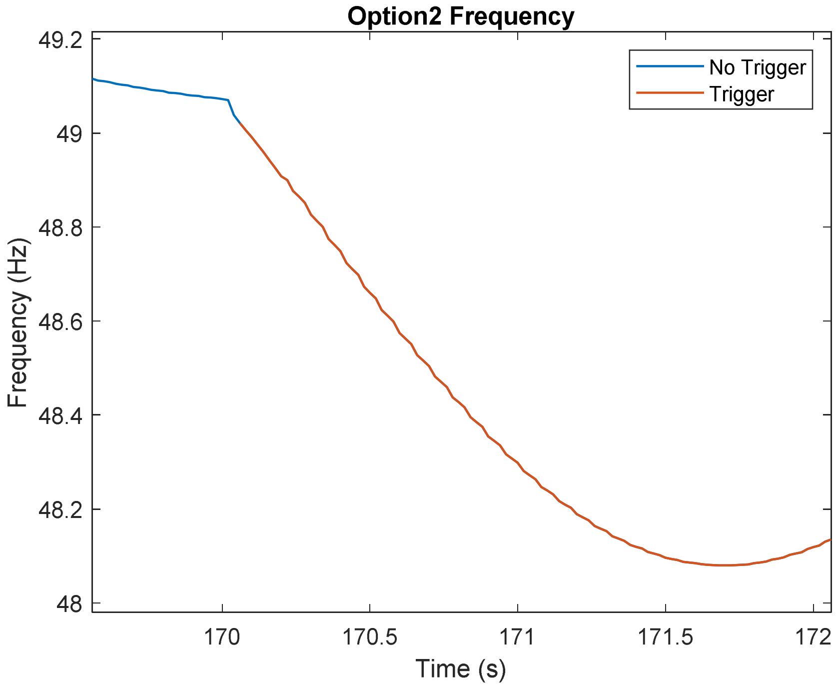

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
140
140.5
141
141.5
142
Time (s)

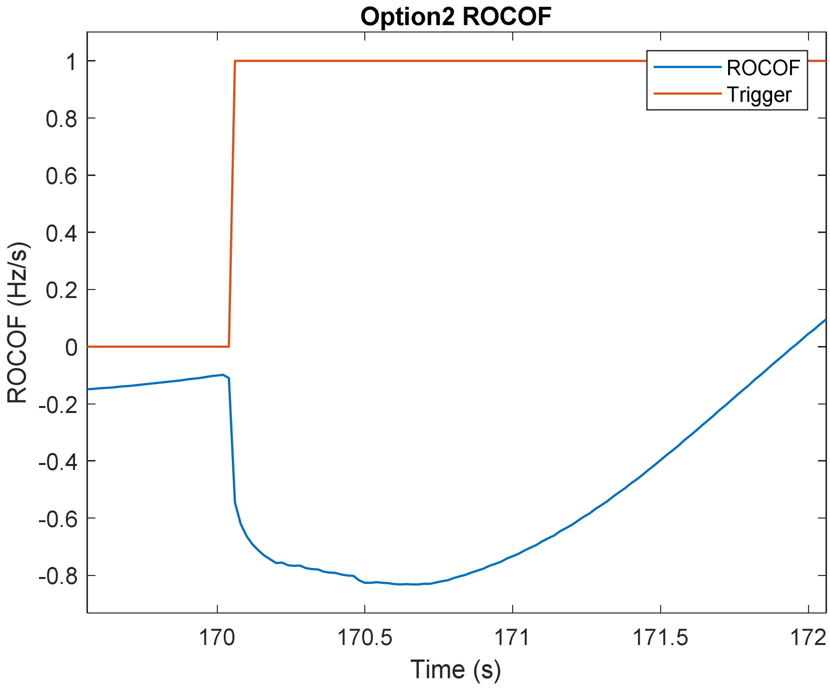

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
-10
-12
140
140.5
141
141.5
142
Time (s)

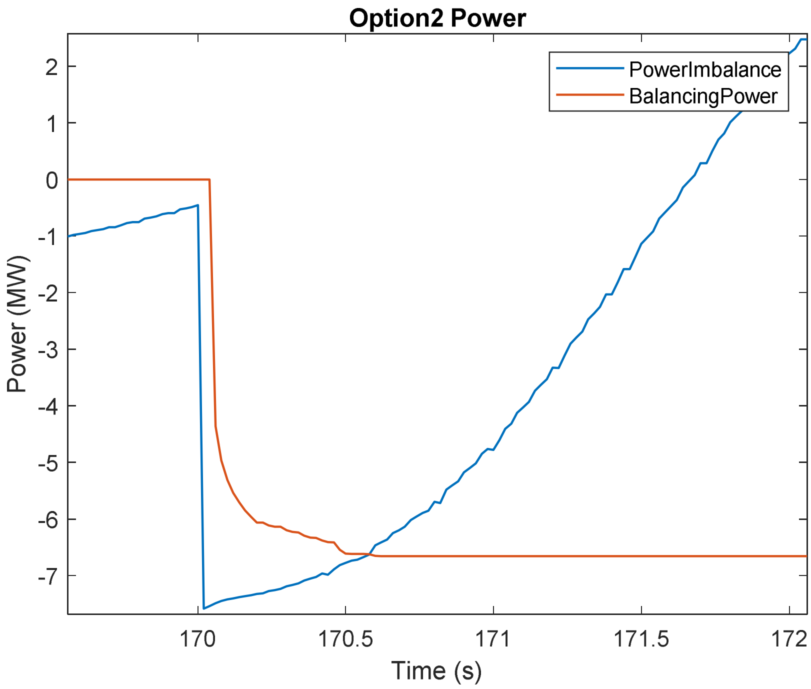

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
160
160.5
161
161.5
162
Time (s)

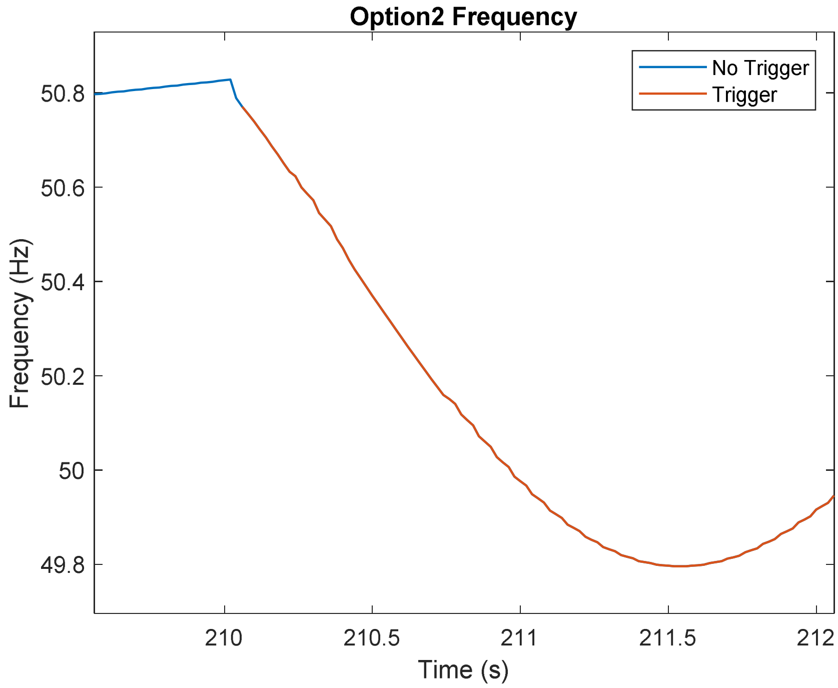

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
160
160.5
161
161.5
162
Time (s)

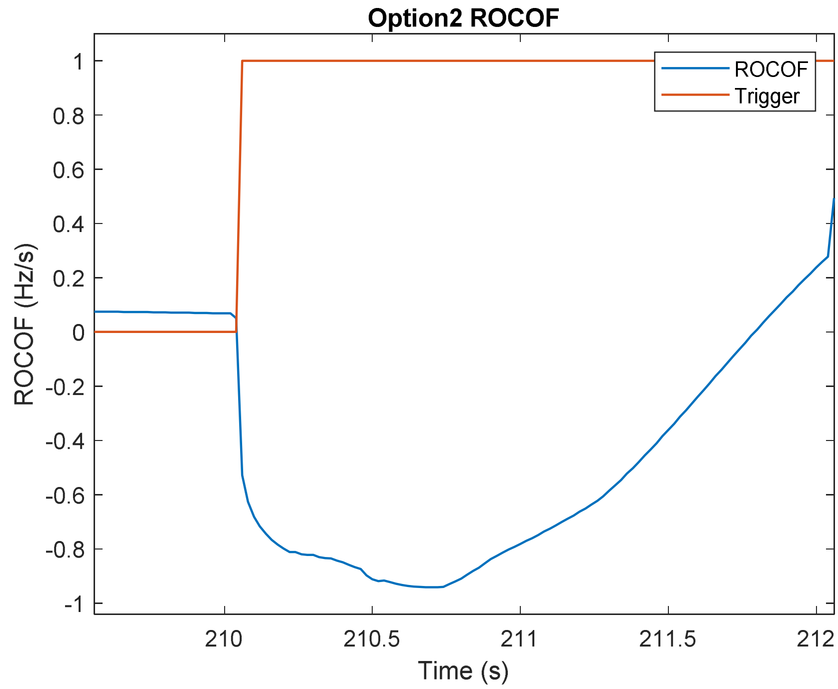

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162
Time (s)

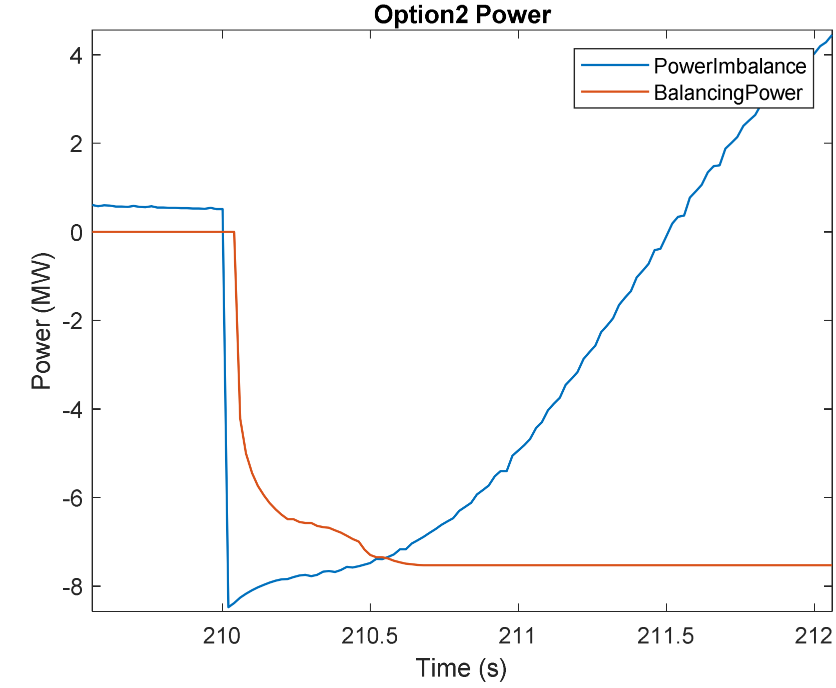

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
49.2
49
48.8
48.6
48.4
48.2
48
170
170.5
171
171.5
172
Time (s)

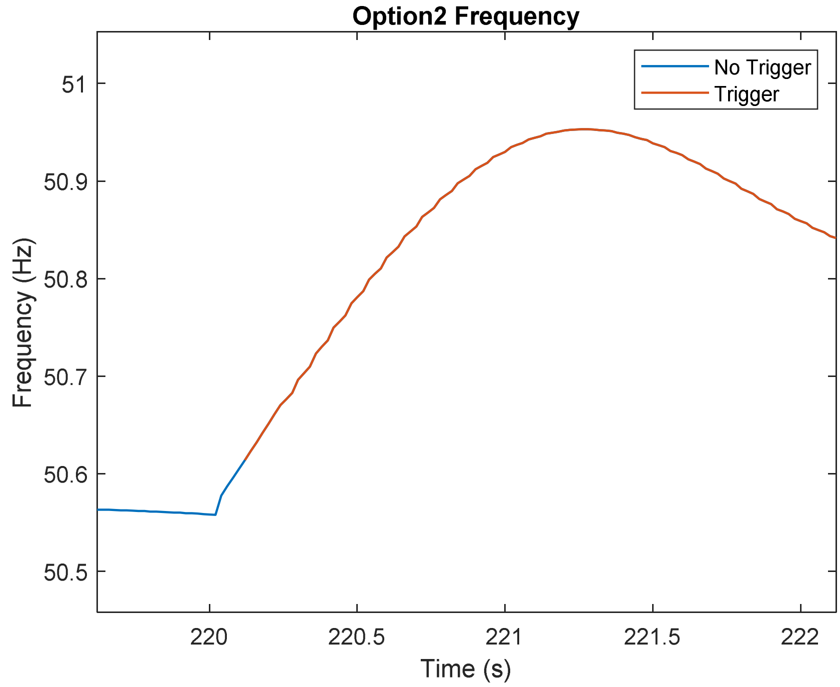

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
170
170.5
171
171.5
172
Time (s)

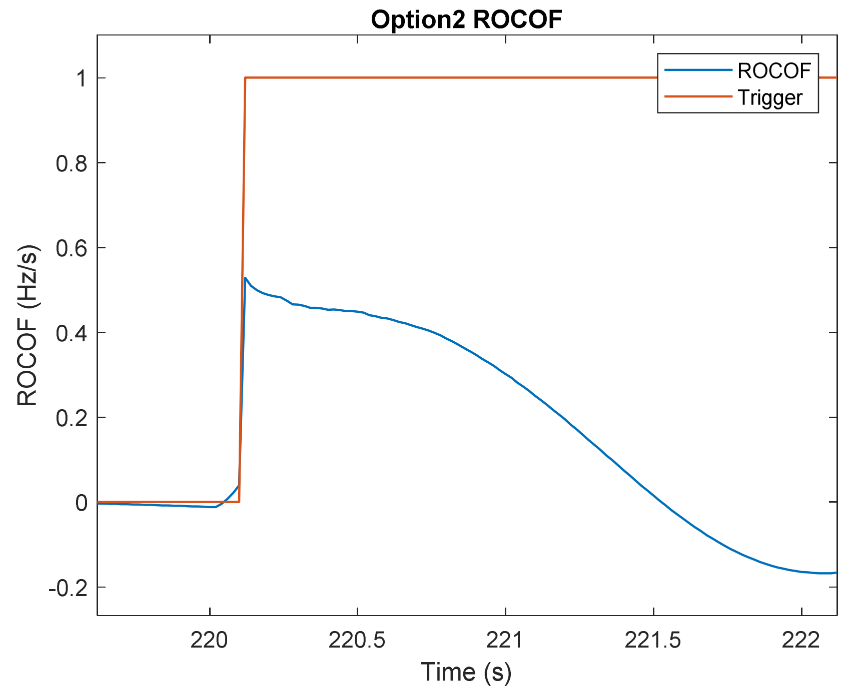

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
2
1
0
-1
-2
-3
-4
-5
-6
-7
170
170.5
171
171.5
172
Time (s)

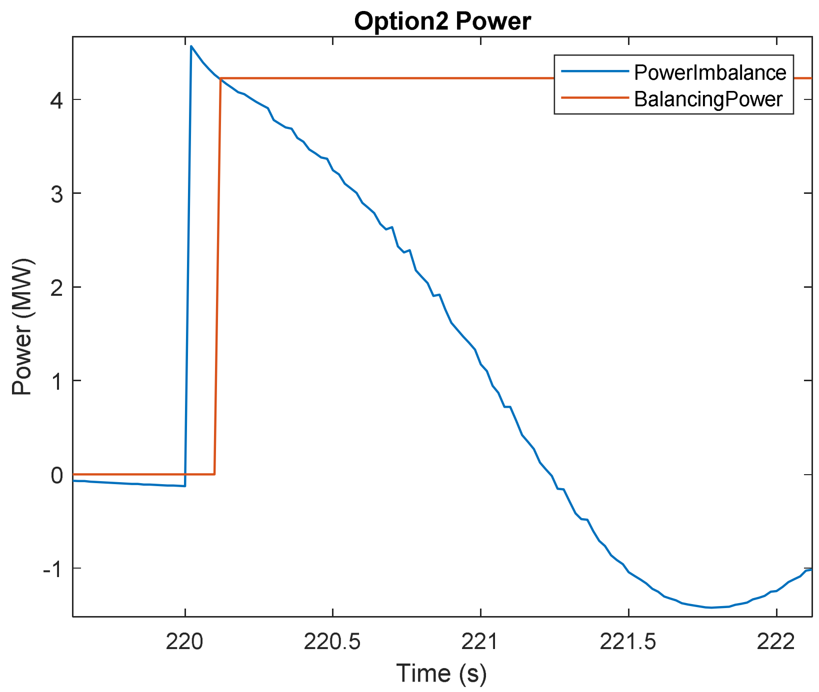

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
50.8
50.6
50.4
50.2
50
49.8
210
210.5
211
211.5
212
Time (s)

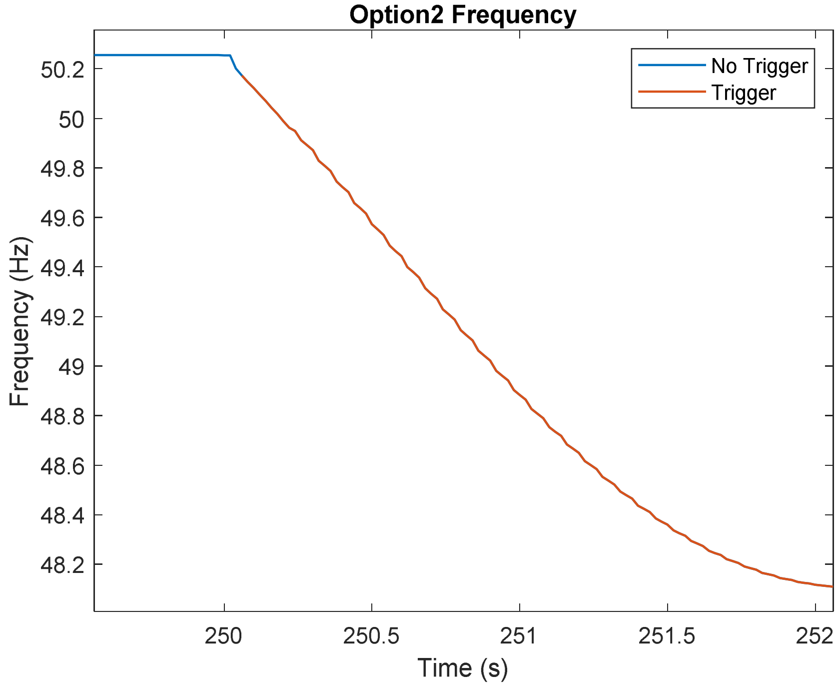

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
210
210.5
211
211.5
212
Time (s)

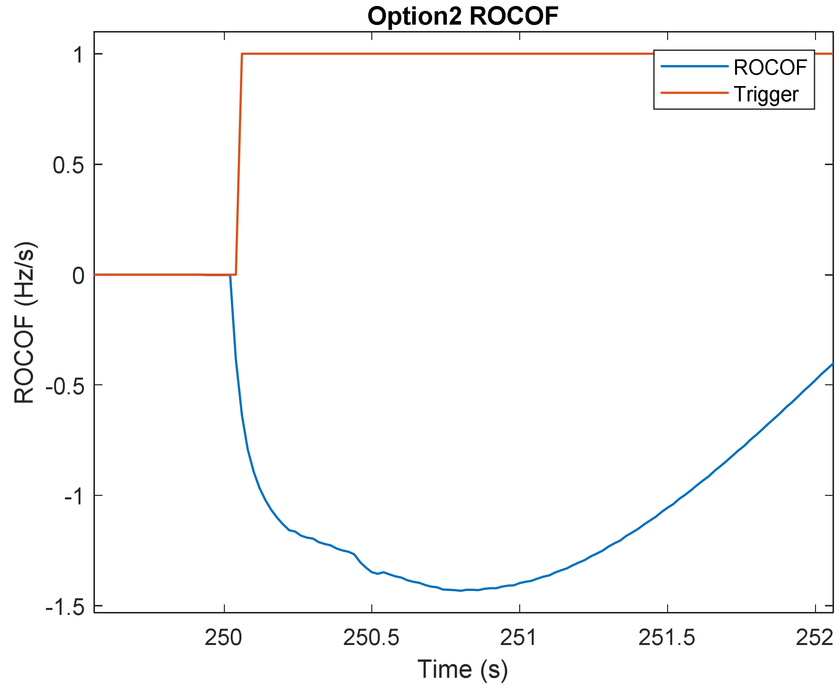

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
4
2
0
-2
-4
-6
-8
210
210.5
211
211.5
212
Time (s)

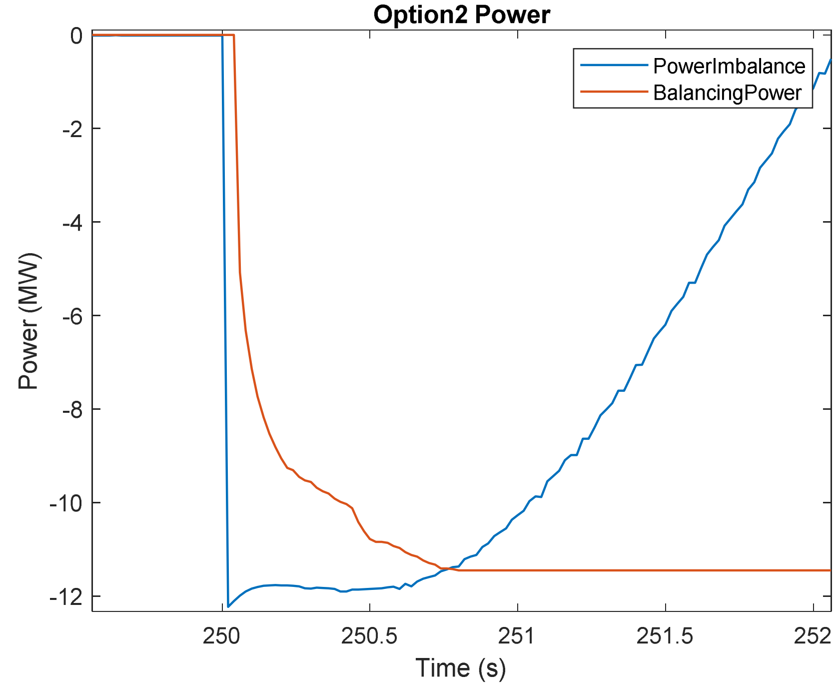

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.9
50.8
50.7
50.6
50.5
220
220.5
221
221.5
222
Time (s)

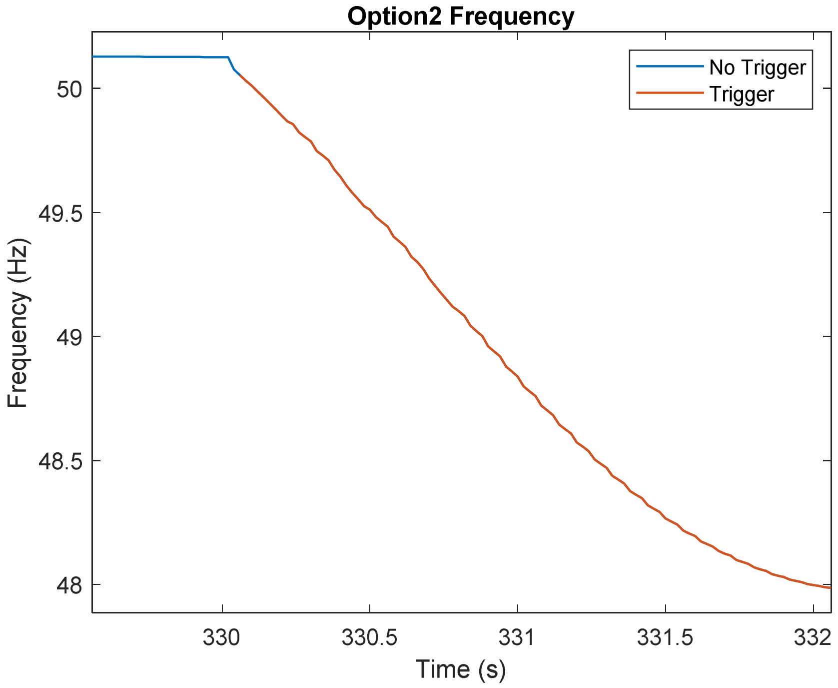

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222
Time (s)

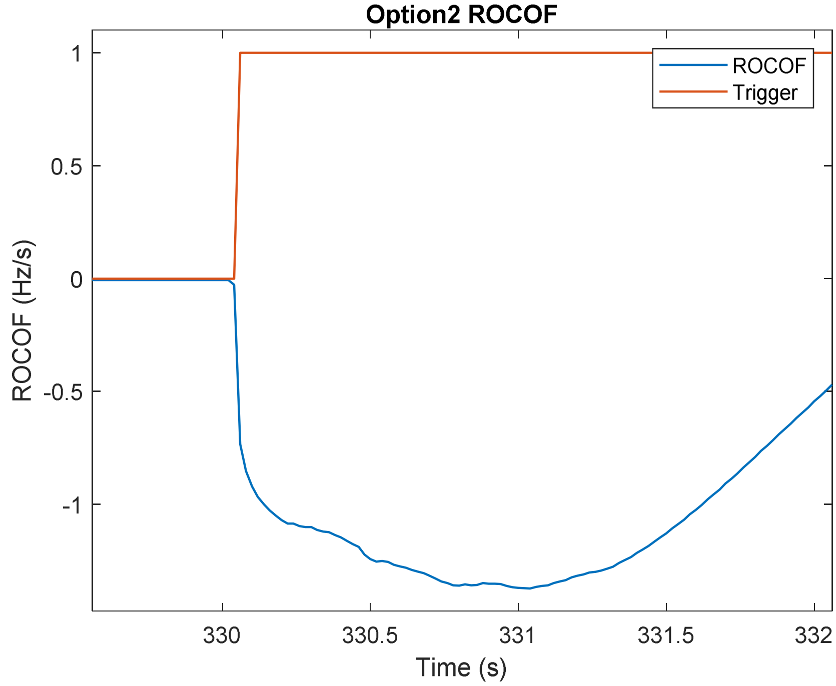

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
220
220.5
221
221.5
222
Time (s)

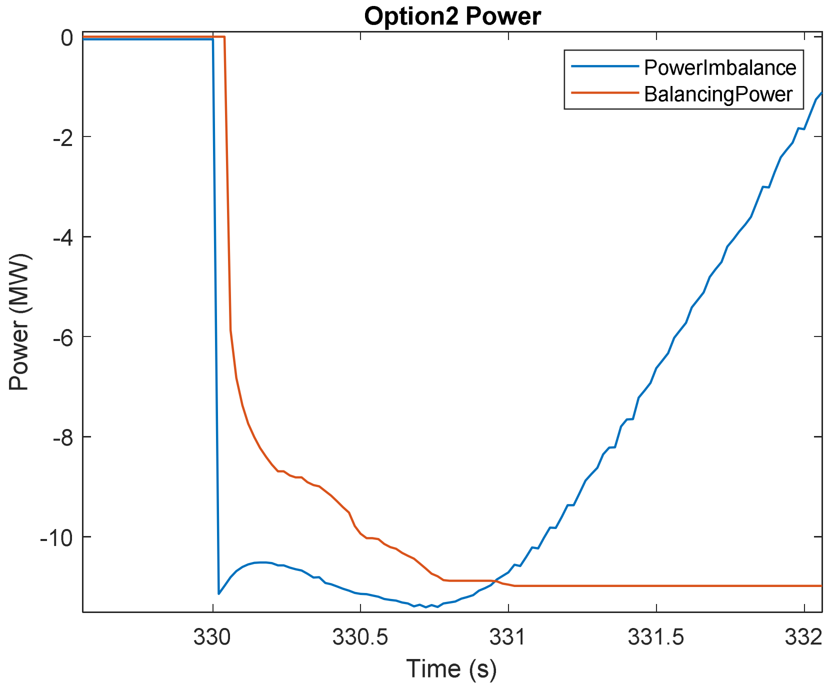

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
50.2
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
250
250.5
251
251.5
252
Time (s)

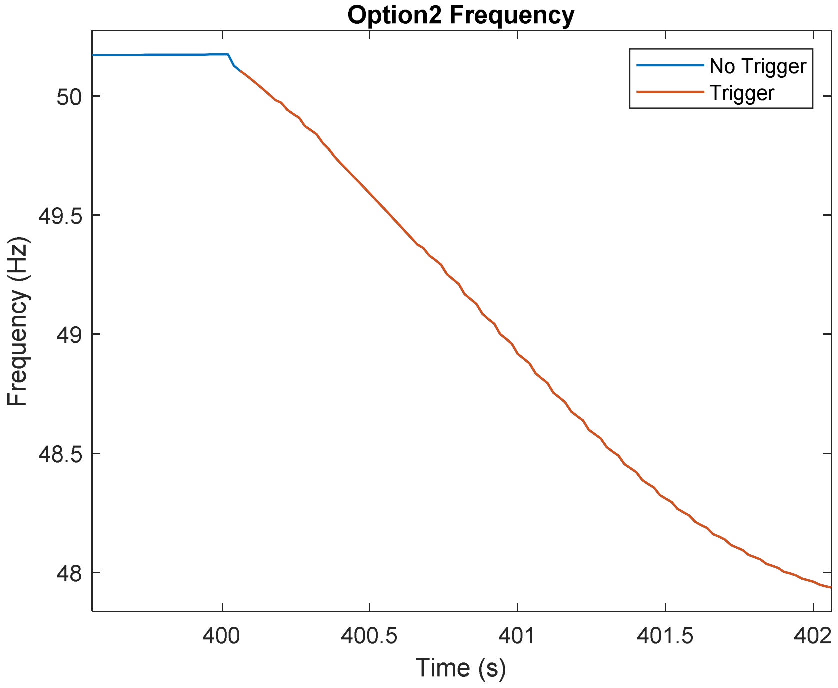

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
250
250.5
251
251.5
252
Time (s)

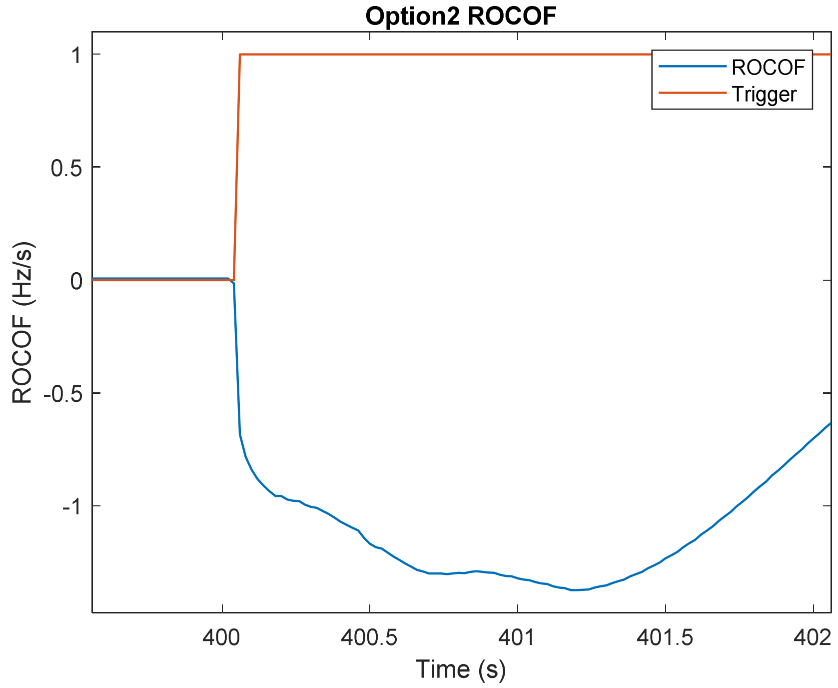

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
250
250.5
251
251.5
252
Time (s)

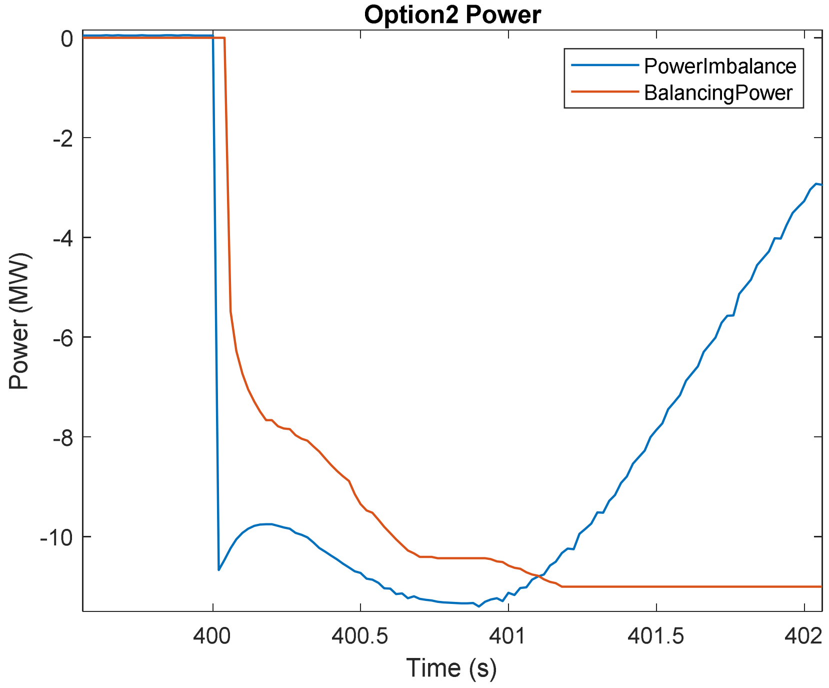

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
330
330.5
331
331.5
332
Time (s)

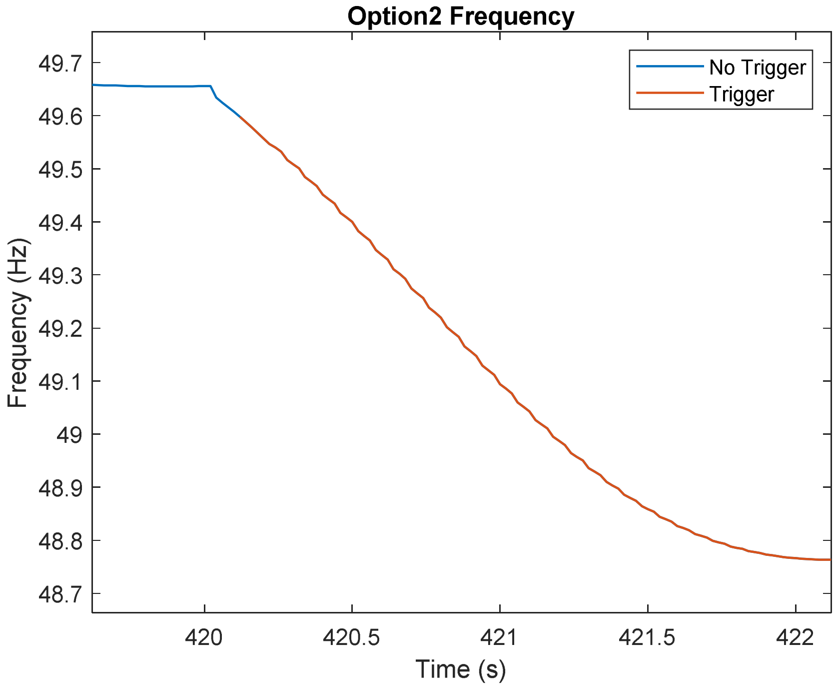

Option2 ROCOF
ROCOF
Trigger
1
0.5
0
-0.5
-1
ROCOF (Hz/s)
330
330.5
331
331.5
332
Time (s)

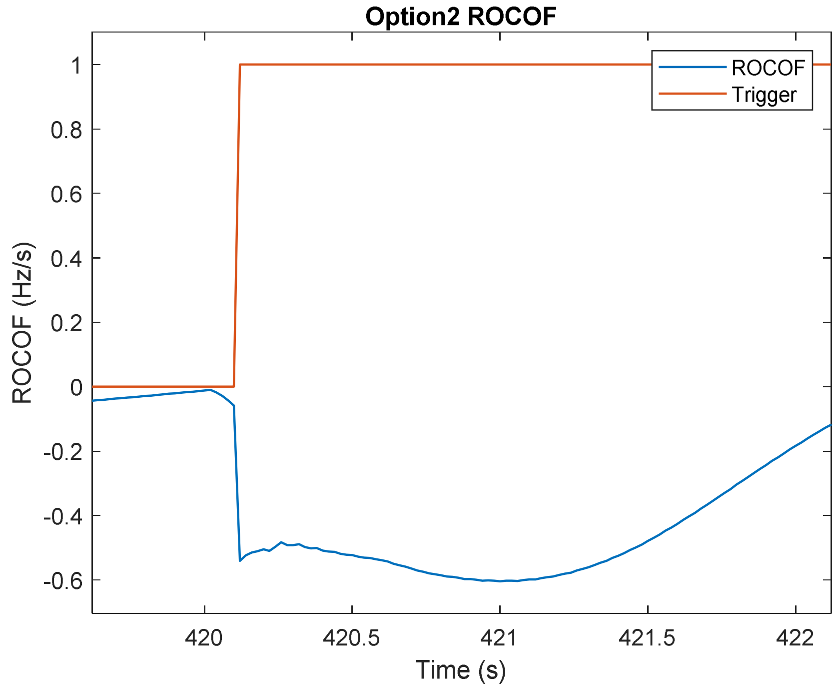

Option2 Power
PowerImbalance
BalancingPower
0
-2
-4
-6
-8
-10
Power (MW)
330
330.5
331
331.5
332
Time (s)

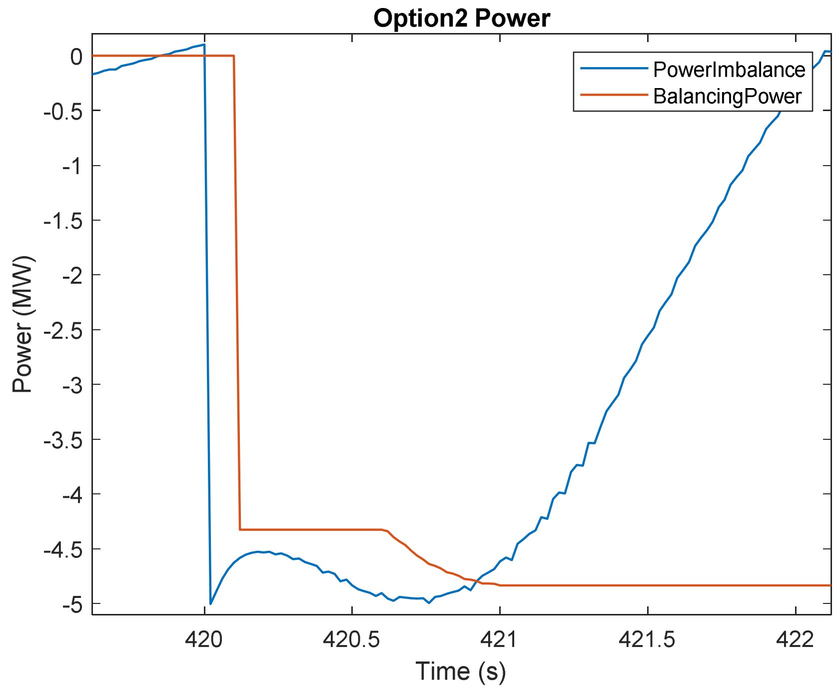

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
400
400.5
401
401.5
402
Time (s)


Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
400
400.5
401
401.5
402
Time (s)

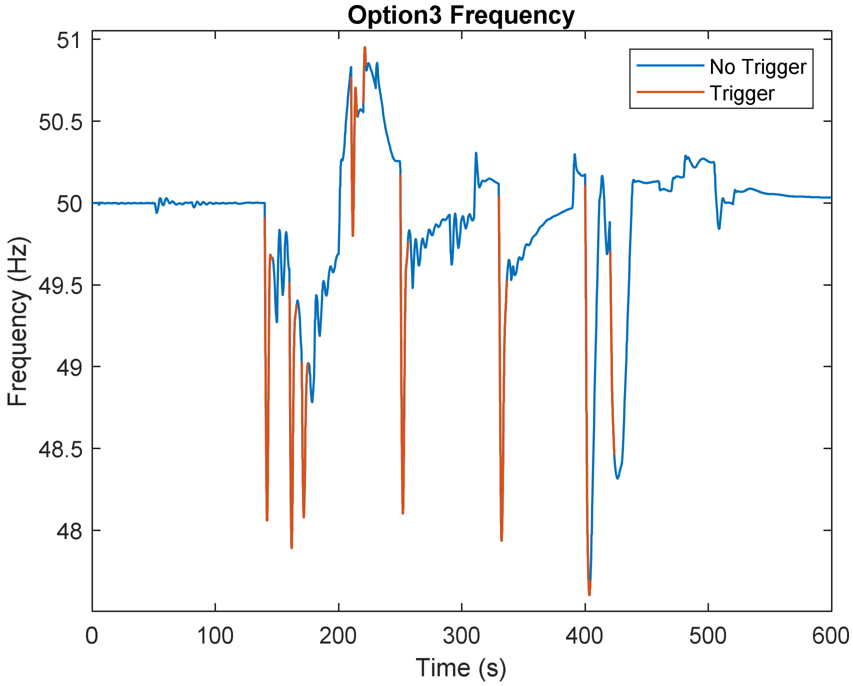

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
400
400.5
401
401.5
402
Time (s)

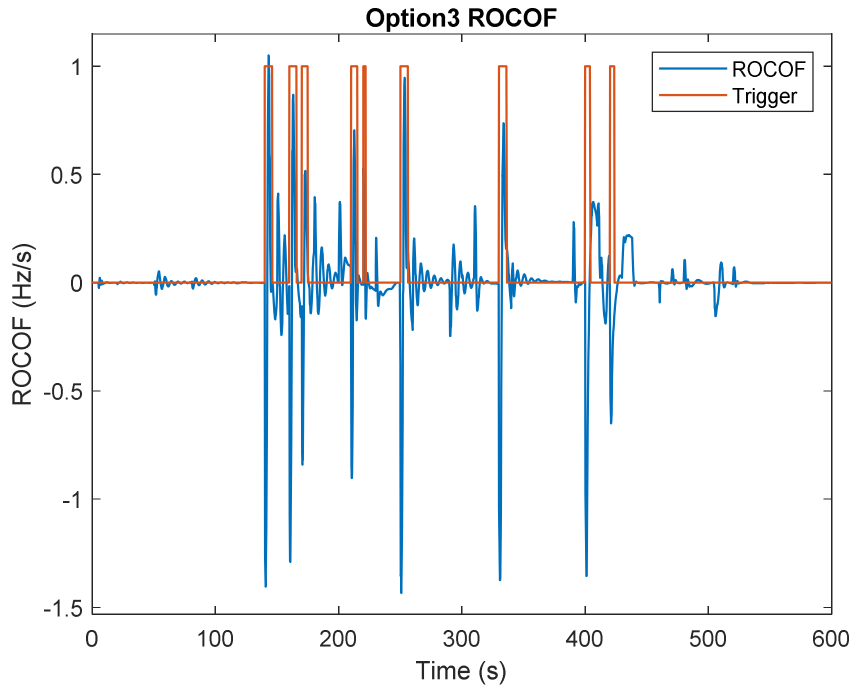

Option2 Frequency
No Trigger
Trigger
Frequency (Hz)
49.7
49.6
49.5
49.4
49.3
49.2
49.1
49
48.9
48.8
48.7
420
420.5
421
421.5
422
Time (s)

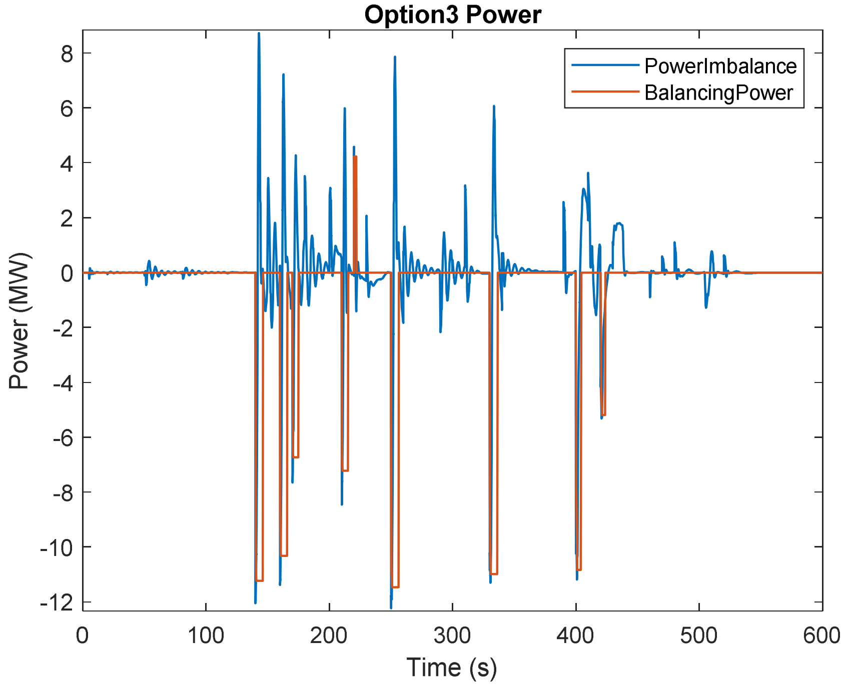

Option2 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
420
420.5
421
421.5
422
Time (s)

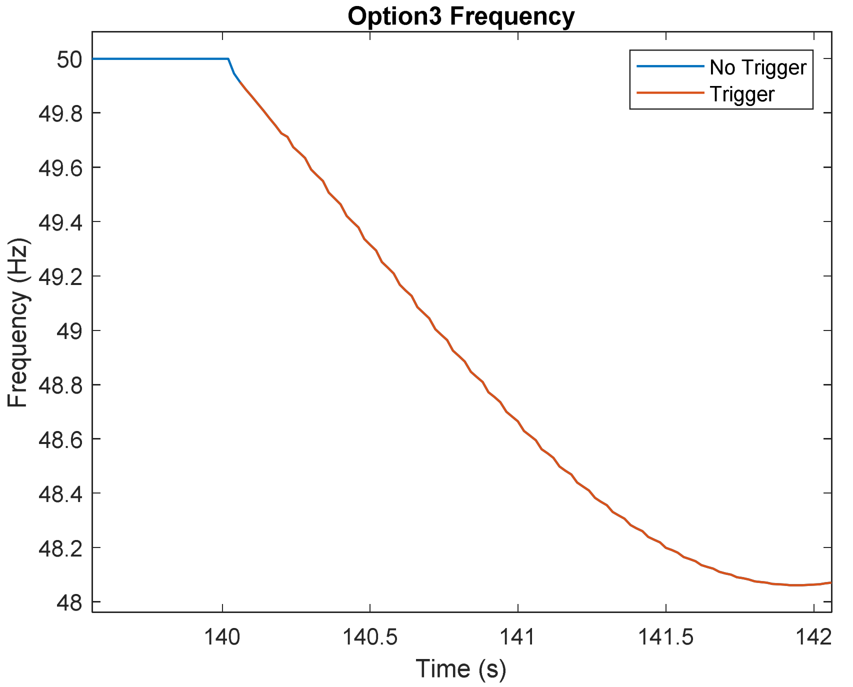

Option2 Power
PowerImbalance
BalancingPower
Power (MW)
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
-5
420
420.5
421
421.5
422
Time (s)

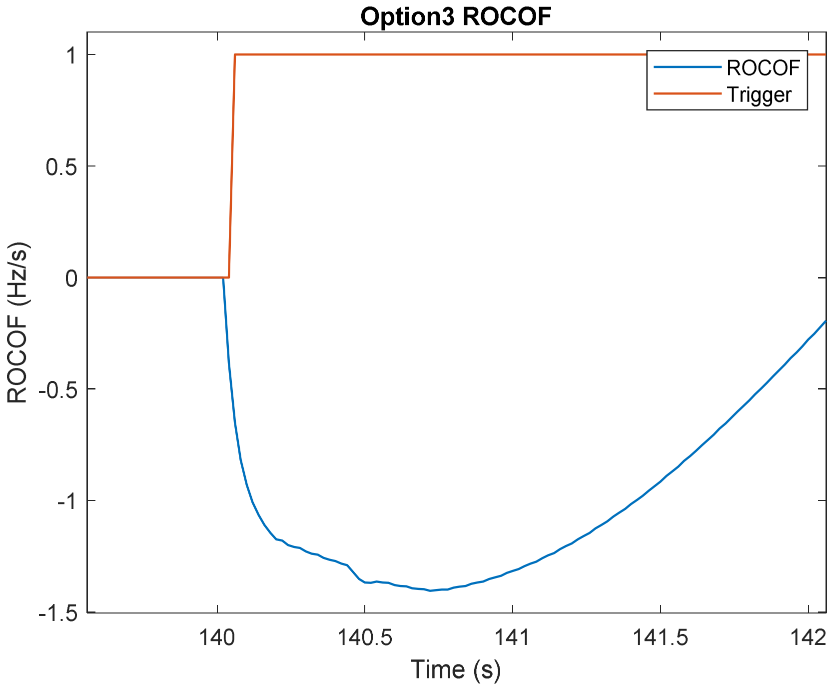
B.1.3 Restoration Option 3

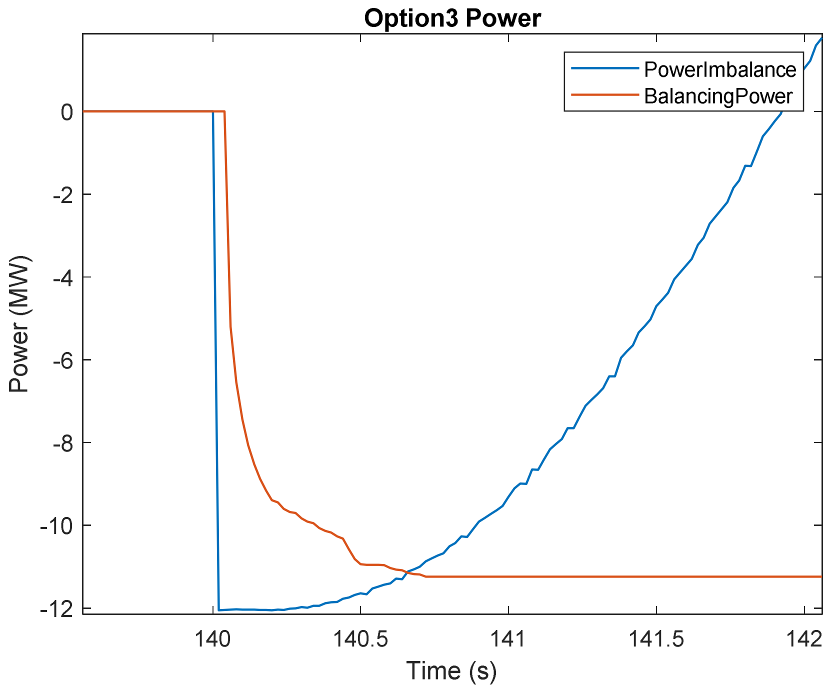


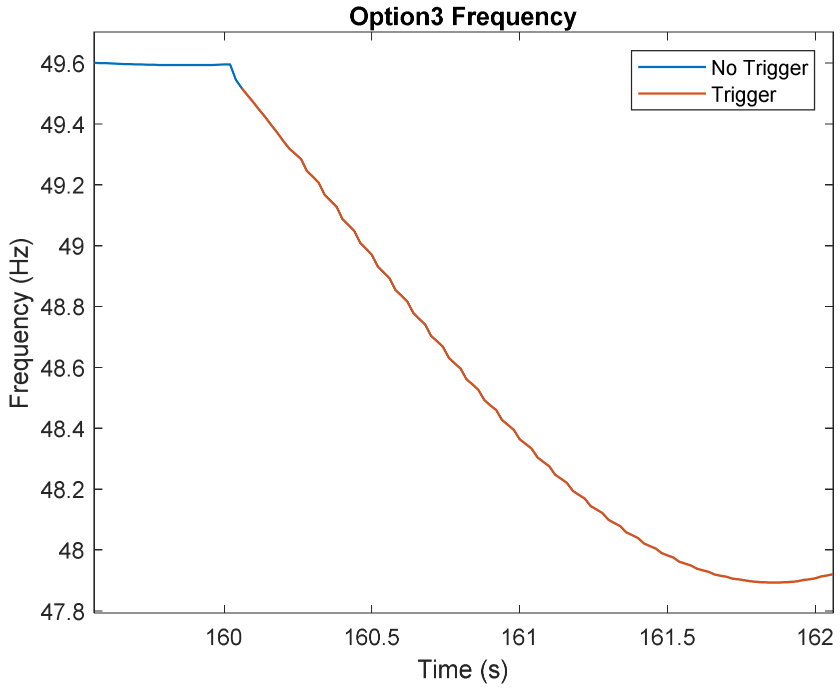


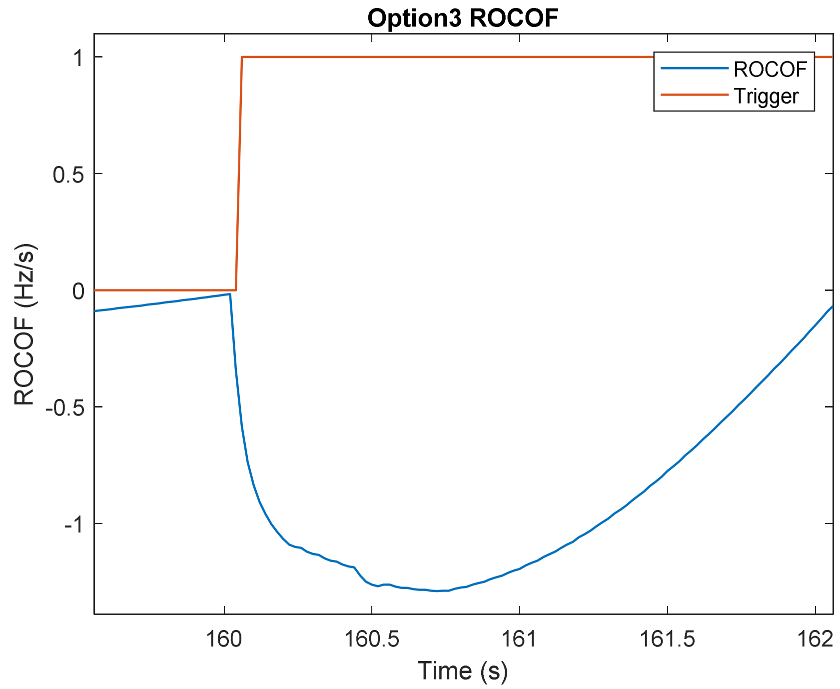

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
8
6
4
2
0
-2
-4
-6
-8
-10
-12
0
100
200
300
400
500
600

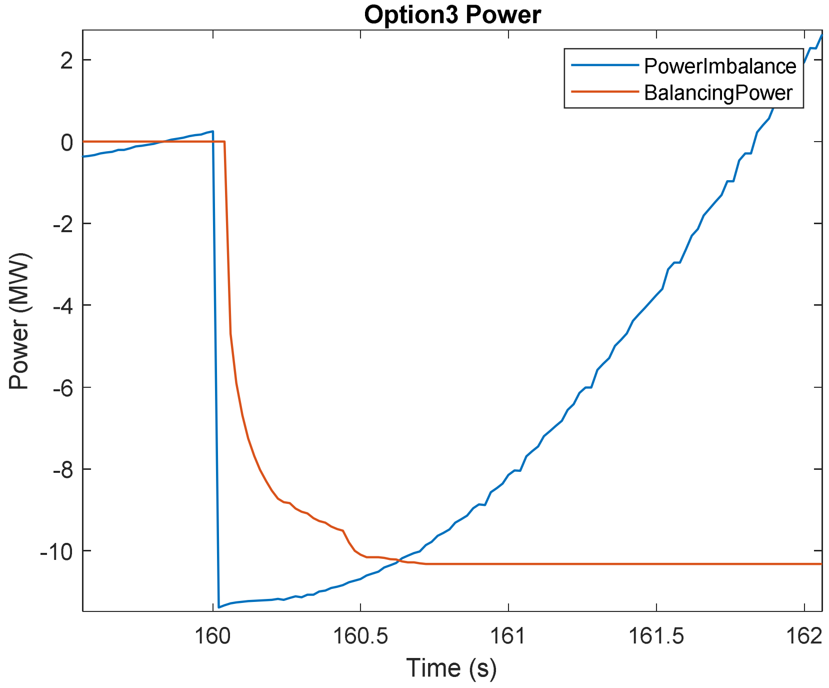

Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
140
140.5
141
141.5
142

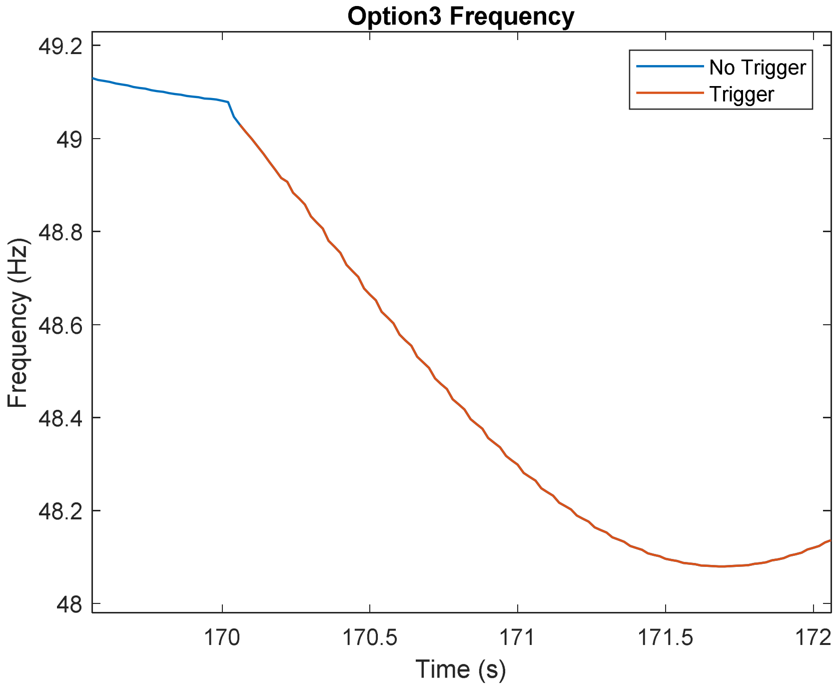

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
140
140.5
141
141.5
142
Time (s)

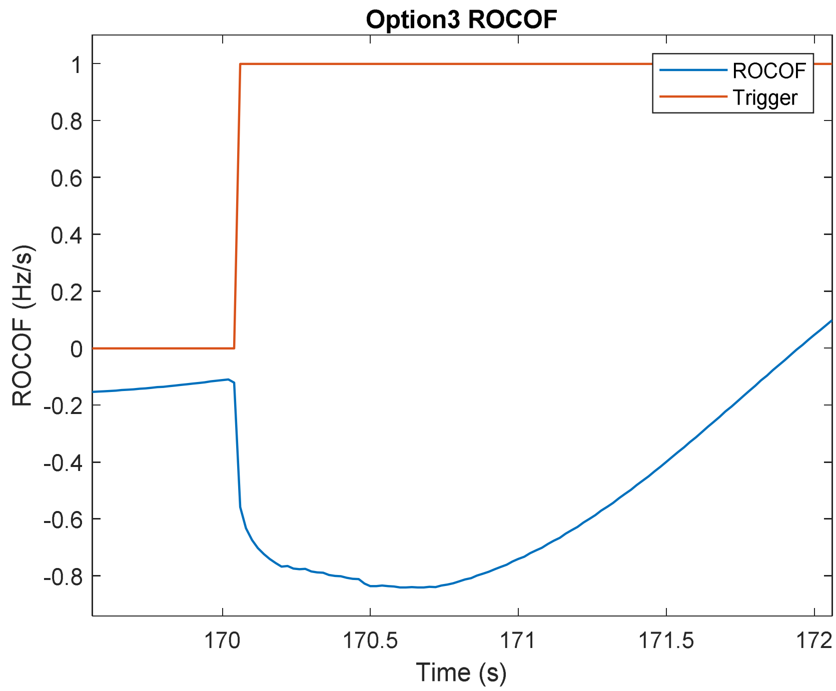

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
140
140.5
141
141.5
142
Time (s)

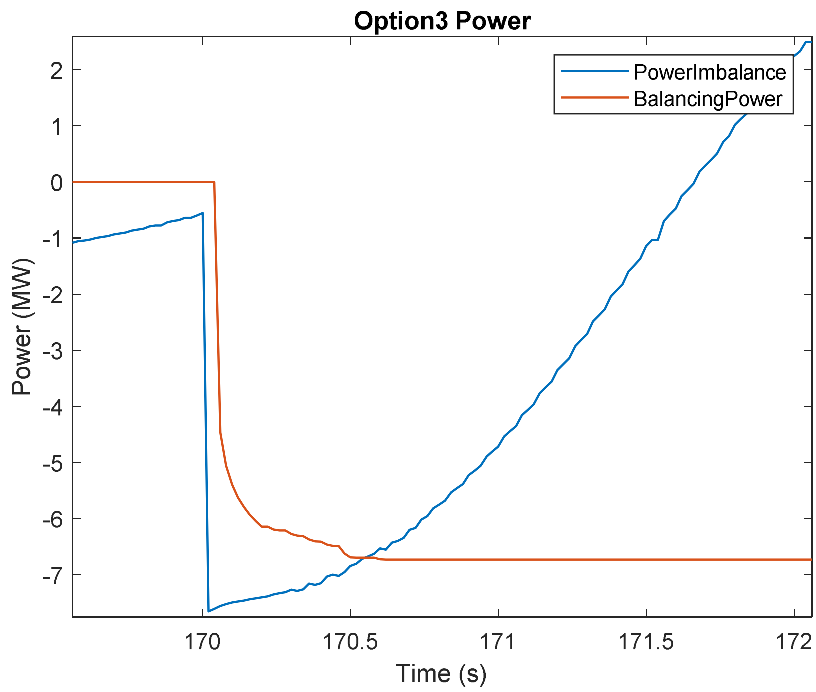

Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
47.8
160
160.5
161
161.5
162
Time (s)

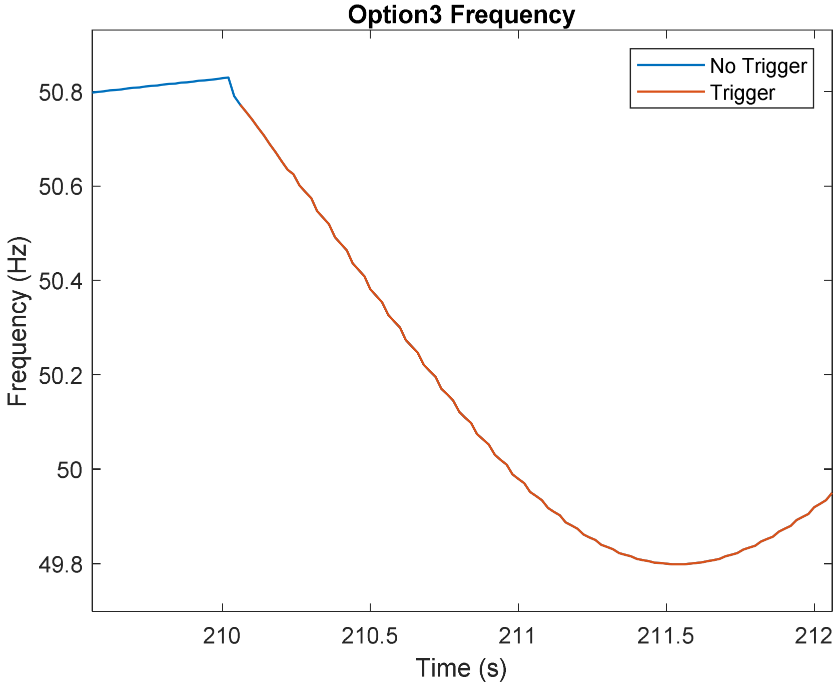

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
160
160.5
161
161.5
162
Time (s)

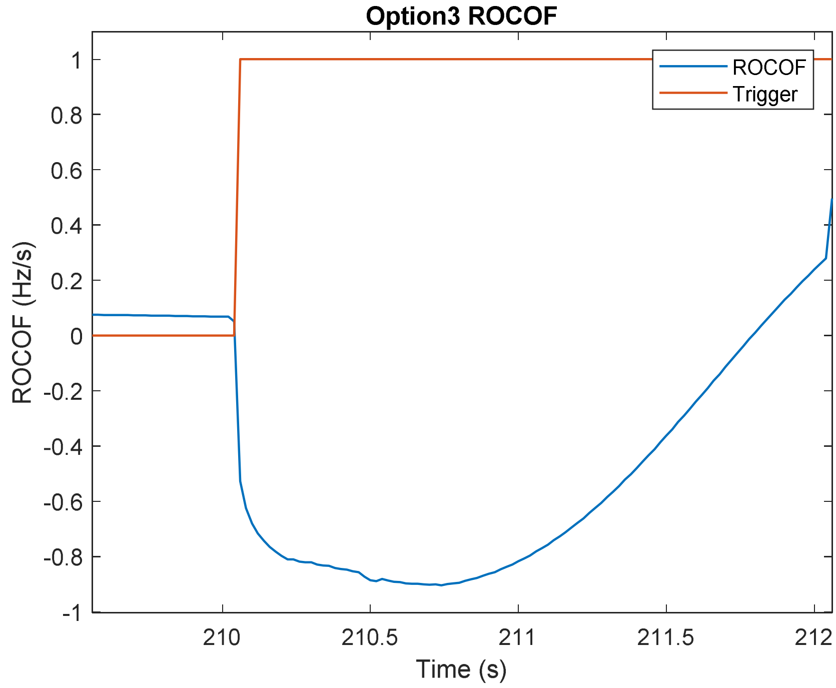

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162

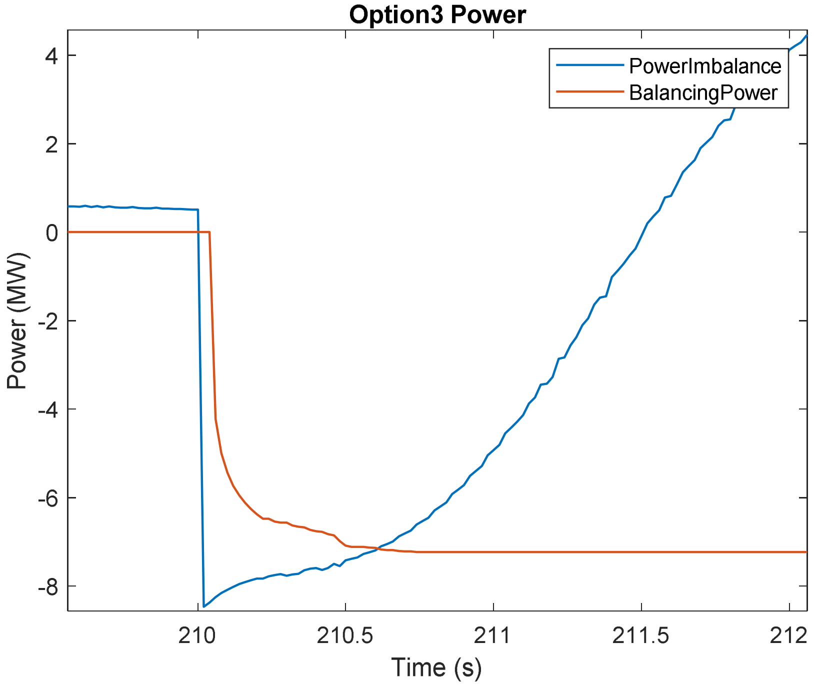

Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
49.2
49
48.8
48.6
48.4
48.2
48
170
170.5
171
171.5
172

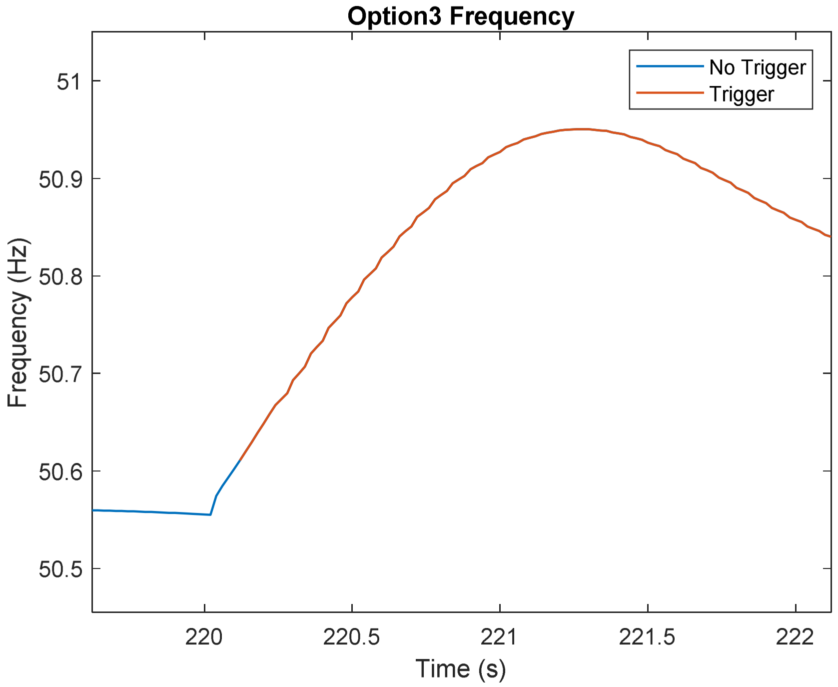

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
170
170.5
171
171.5
172
Time (s)

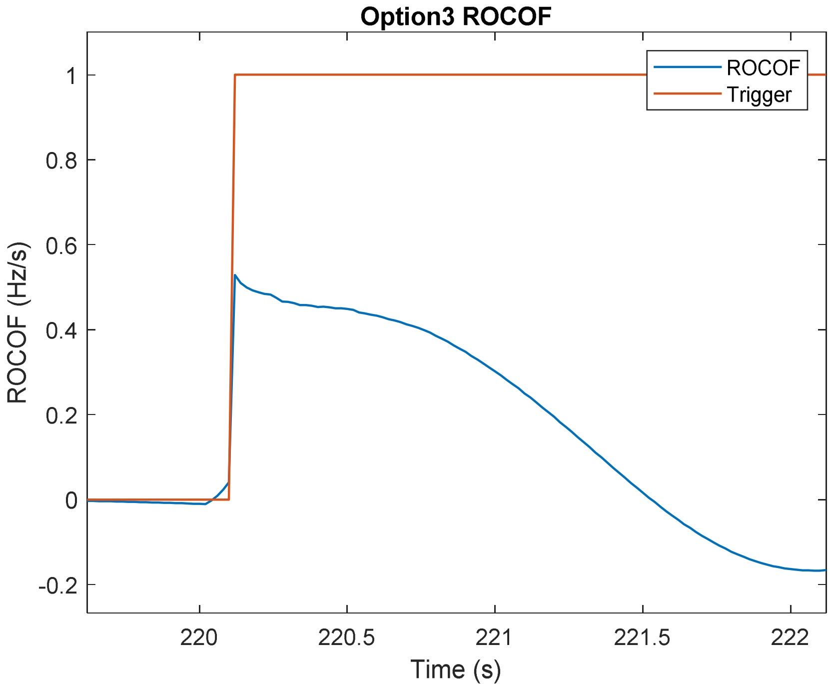

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
2
1
0
-1
-2
-3
-4
-5
-6
-7
170
170.5
171
171.5
172
Time (s)

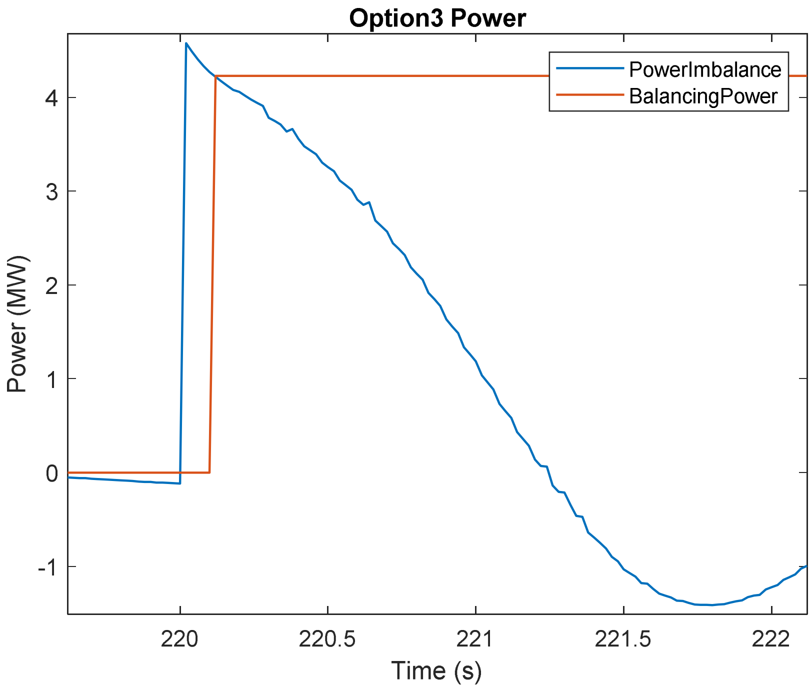

Option3 Frequency
No Trigger
Trigger
50.8
50.6
50.4
50.2
50
49.8
Frequency (Hz)
210
210.5
211
211.5
212
Time (s)

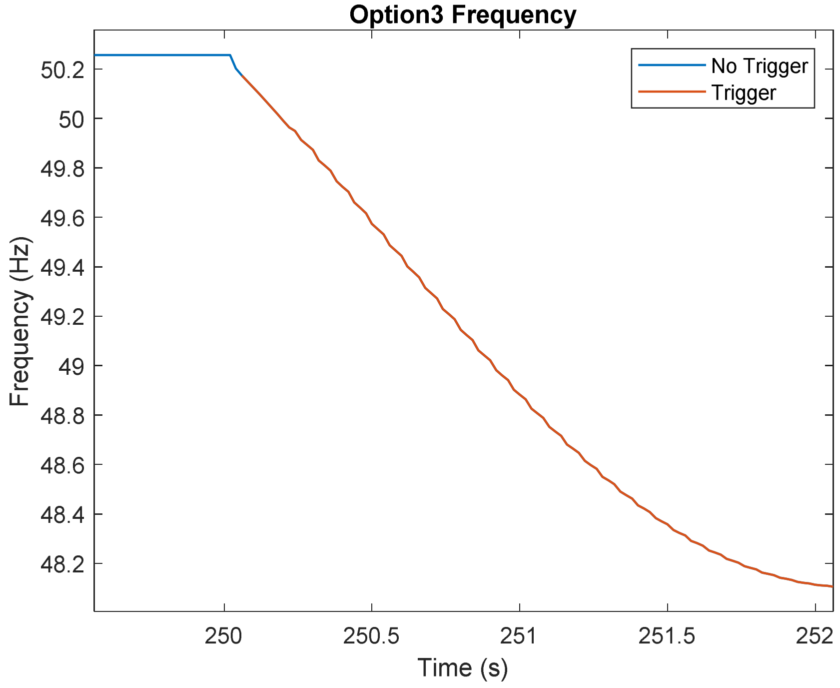

Option3 ROCOF
ROCOF
Trigger
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
ROCOF (Hz/s)
210
210.5
211
211.5
212
Time (s)

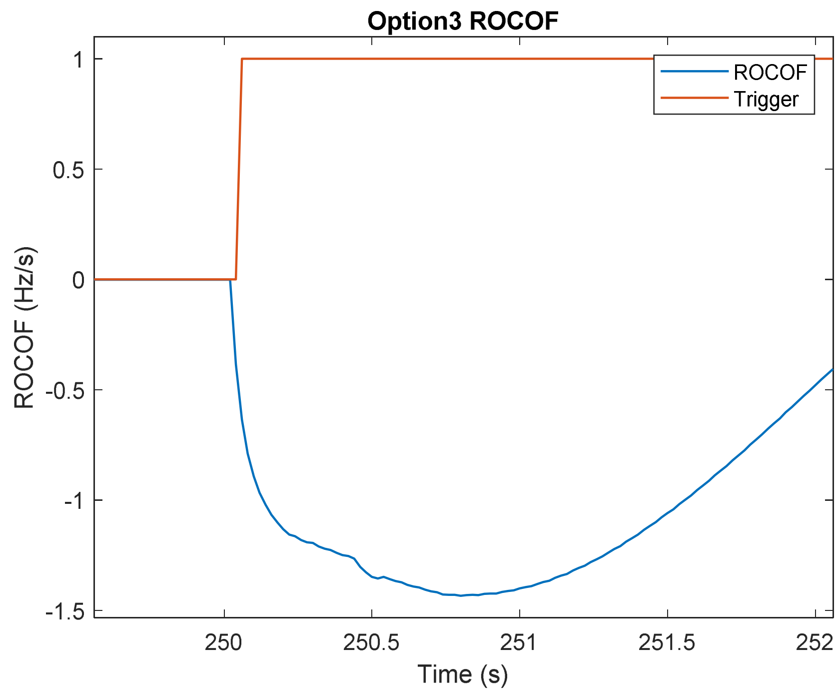

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
4
2
0
-2
-4
-6
-8
210
210.5
211
211.5
212

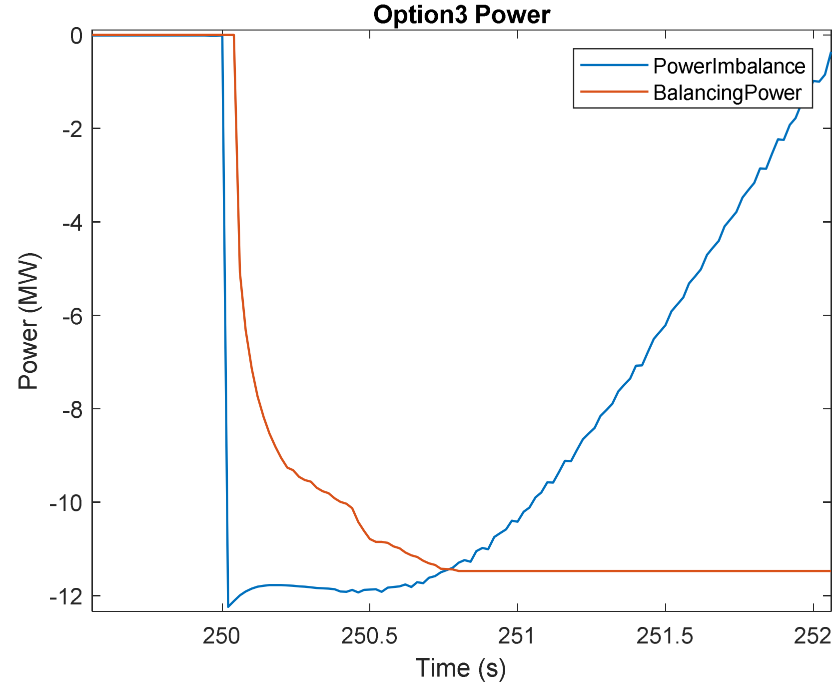

Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
51
50.9
50.8
50.7
50.6
50.5
220
220.5
221
221.5
222

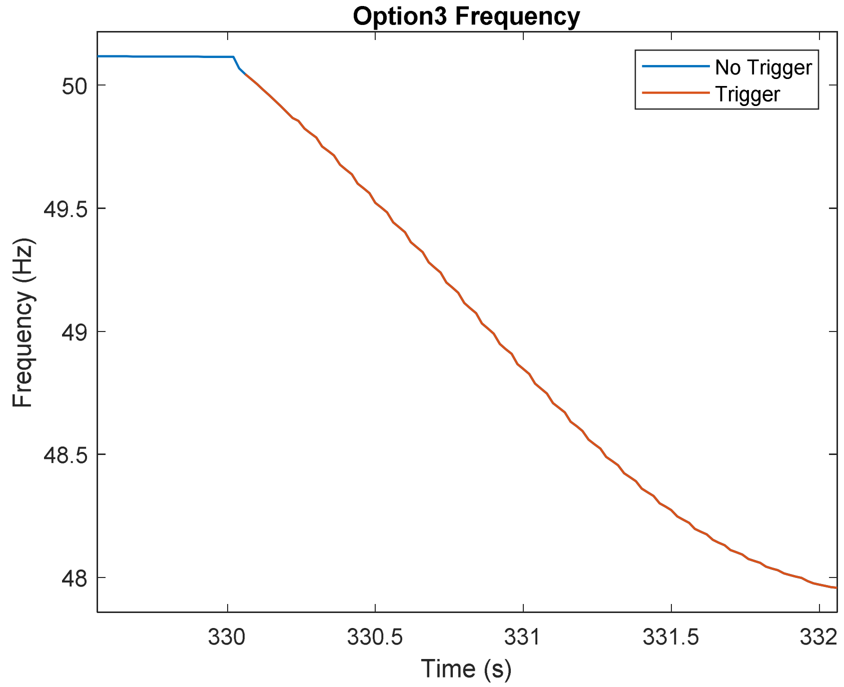

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222
Time (s)

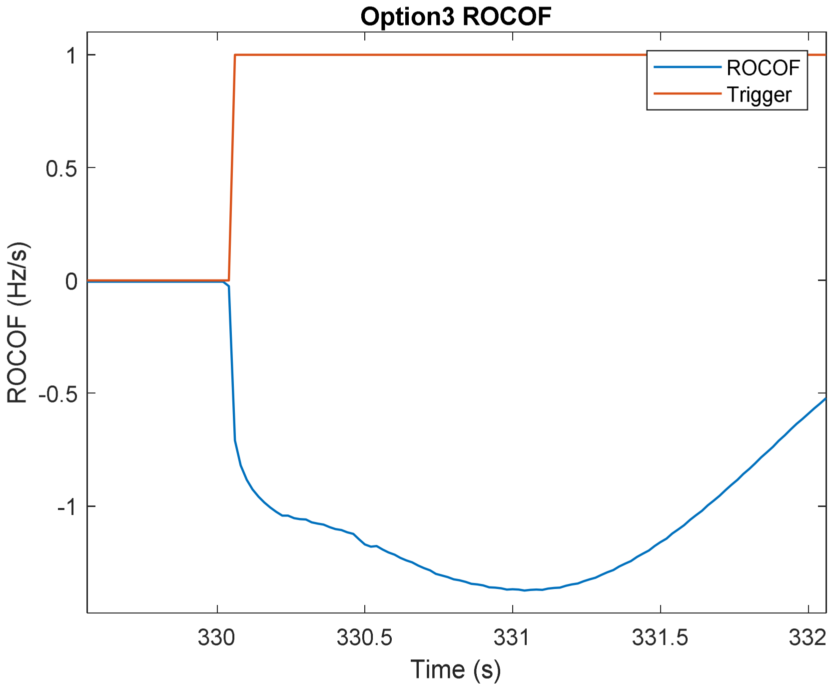

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
220
220.5
221
221.5
222
Time (s)

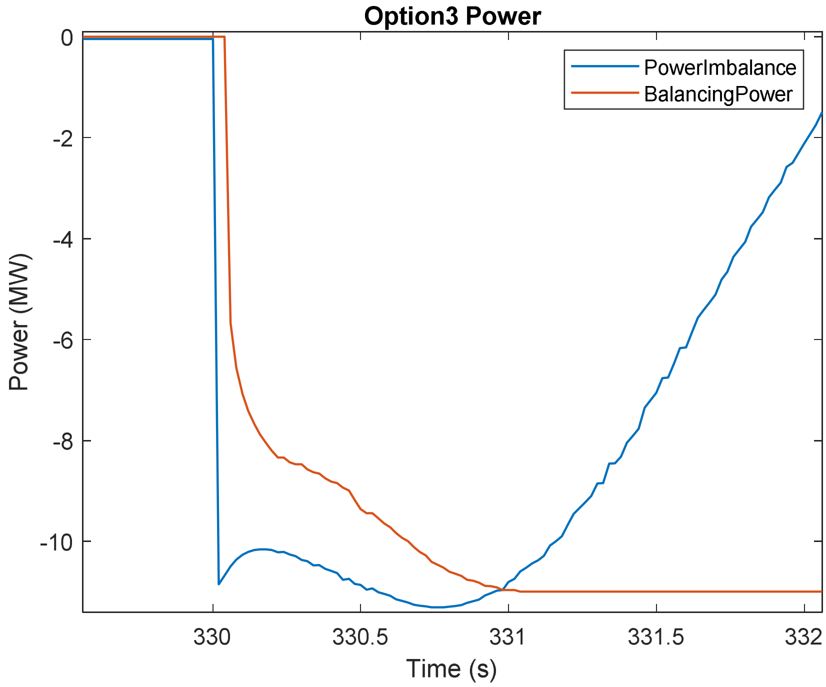

Option3 Frequency
No Trigger
Trigger
50.2
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
Frequency (Hz)
250
250.5
251
251.5
252
Time (s)

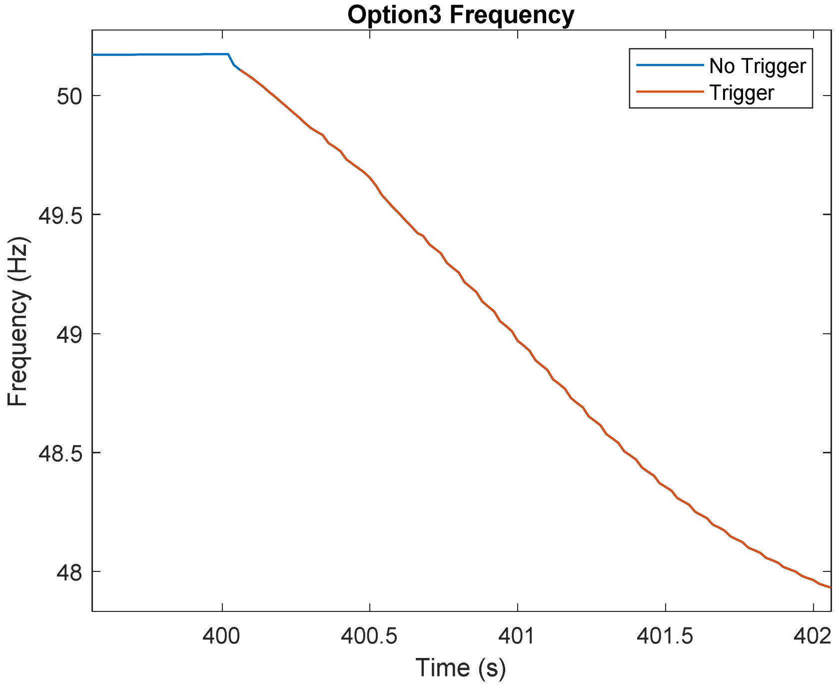

Option3 ROCOF
ROCOF
Trigger
1
0.5
0
-0.5
-1
-1.5
ROCOF (Hz/s)
250
250.5
251
251.5
252
Time (s)

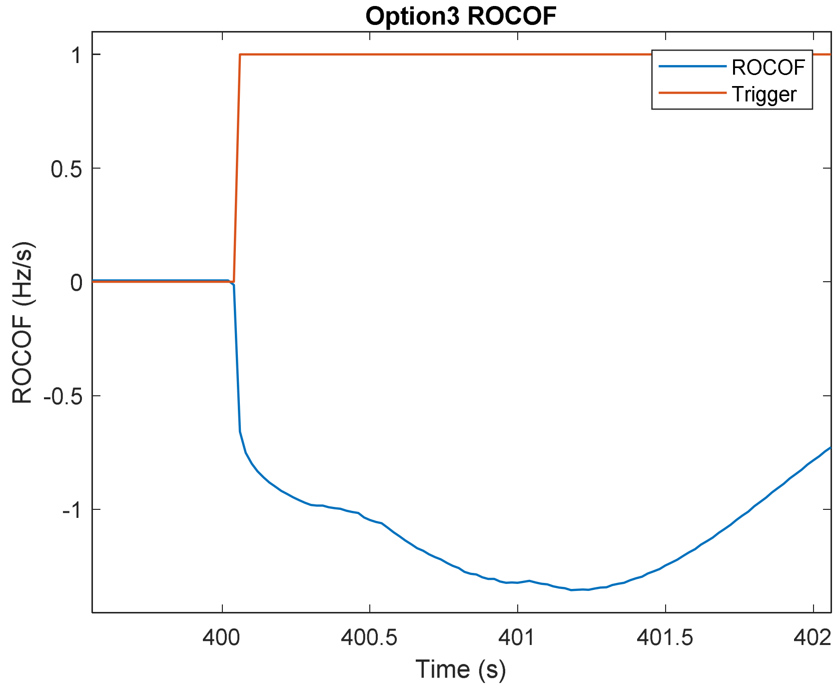

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
250
250.5
251
251.5
252
Time (s)

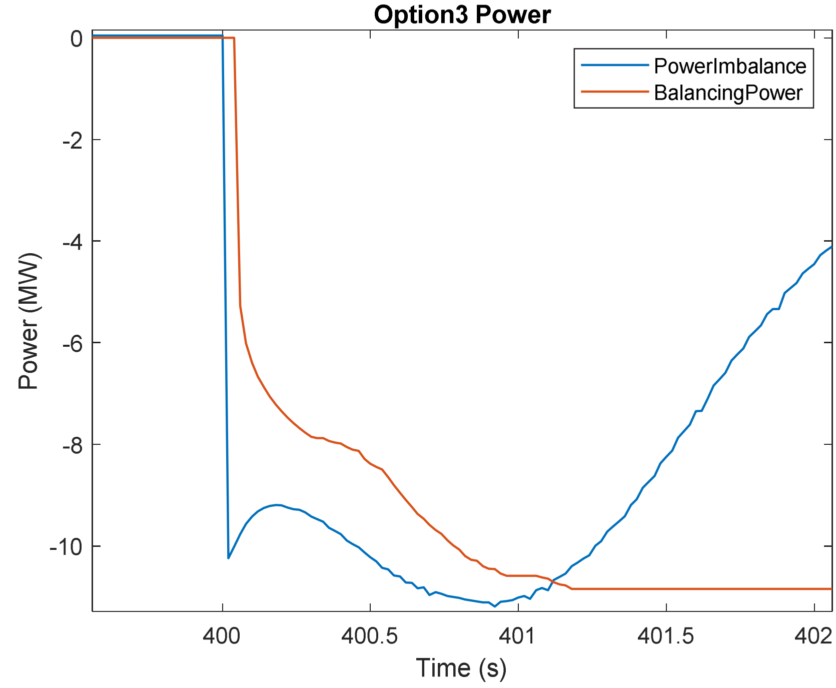

Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
330
330.5
331
331.5
332
Time (s)


Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
330
330.5
331
331.5
332
Time (s)

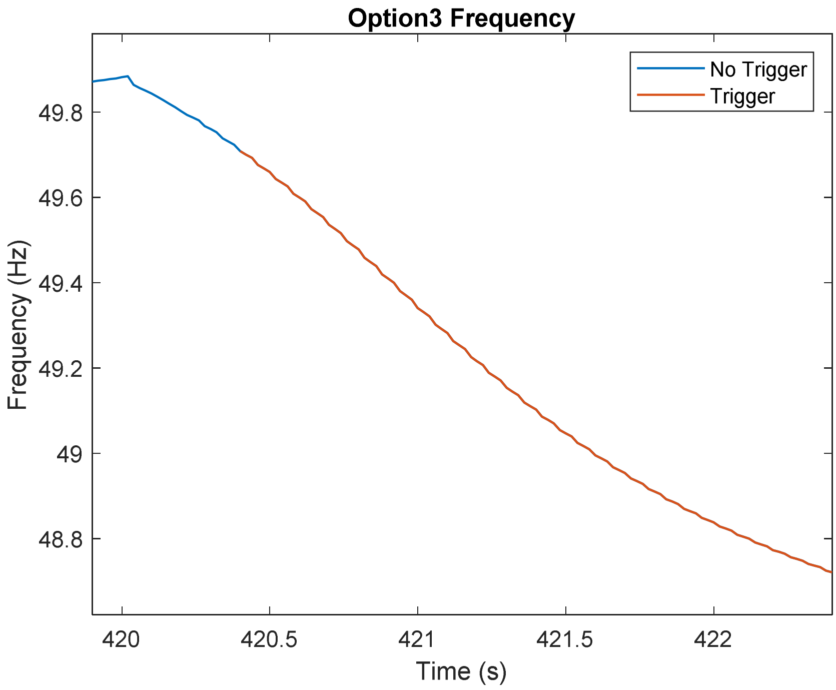

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
330
330.5
331
331.5
332
Time (s)


Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
400
400.5
401
401.5
402
Time (s)

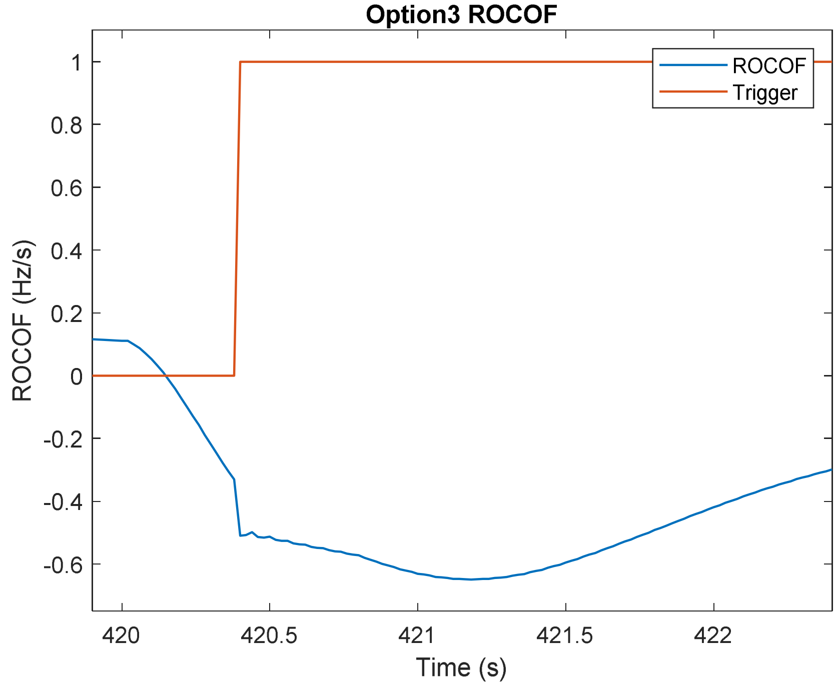

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
400
400.5
401
401.5
402
Time (s)

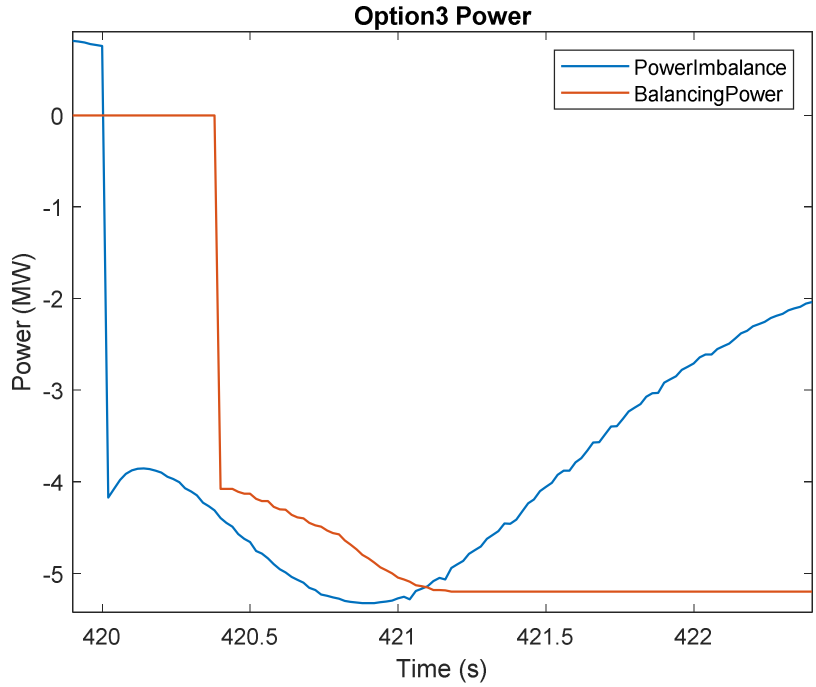


Option3 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
400
400.5
401
401.5
402
Time (s)

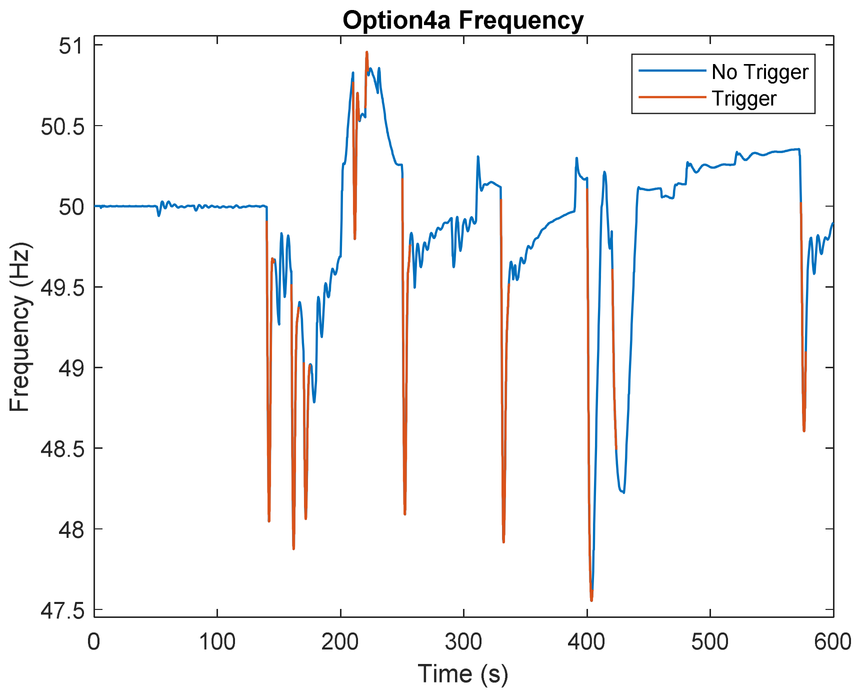


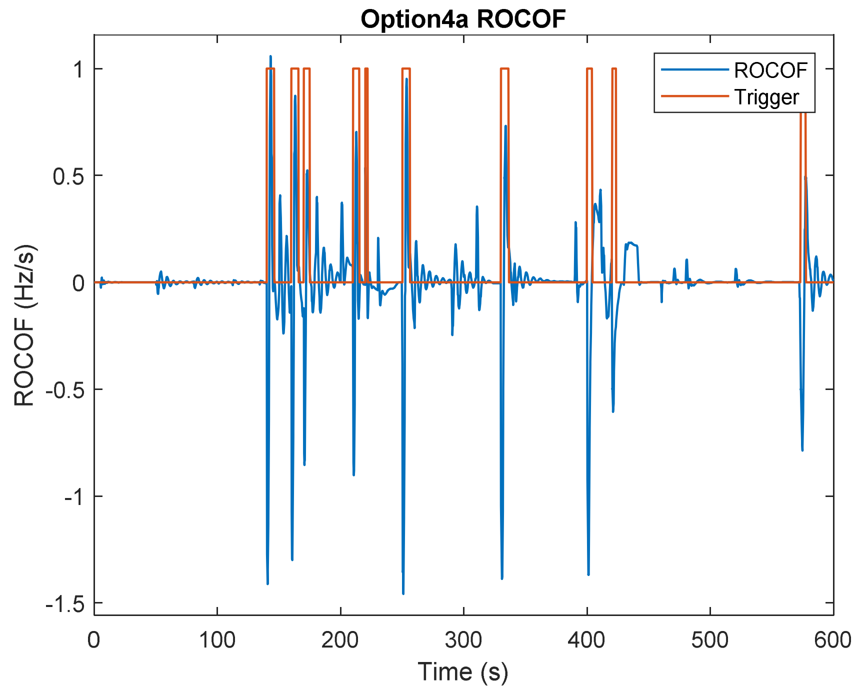
Option3 Frequency
No Trigger
Trigger
Frequency (Hz)
49.8
49.6
49.4
49.2
49
48.8
420
420.5
421
421.5
422
Time (s)

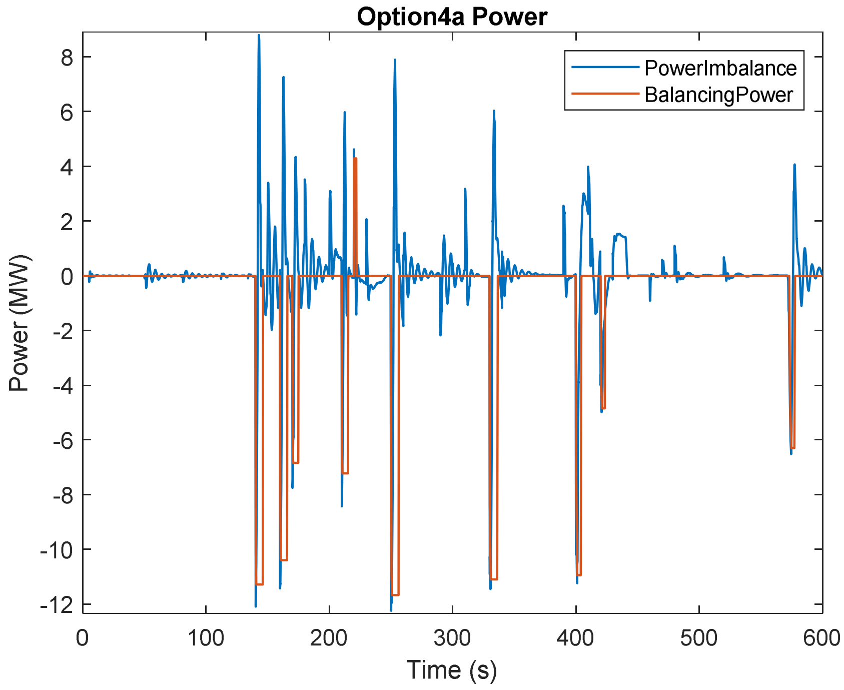

Option3 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
420
420.5
421
421.5
422
Time (s)

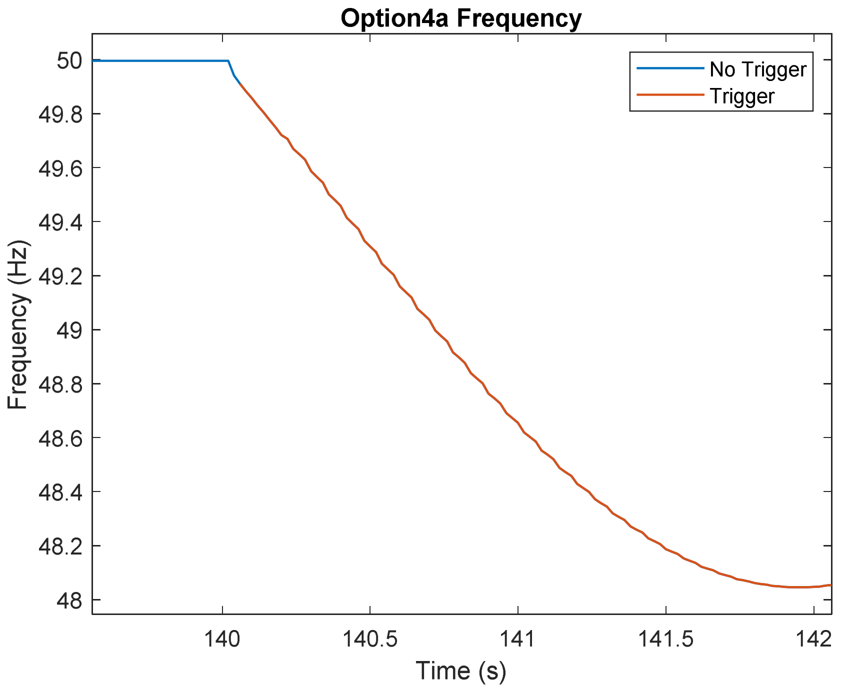

Option3 Power
PowerImbalance
BalancingPower
Power (MW)
0
-1
-2
-3
-4
-5
420
420.5
421
421.5
422
Time (s)

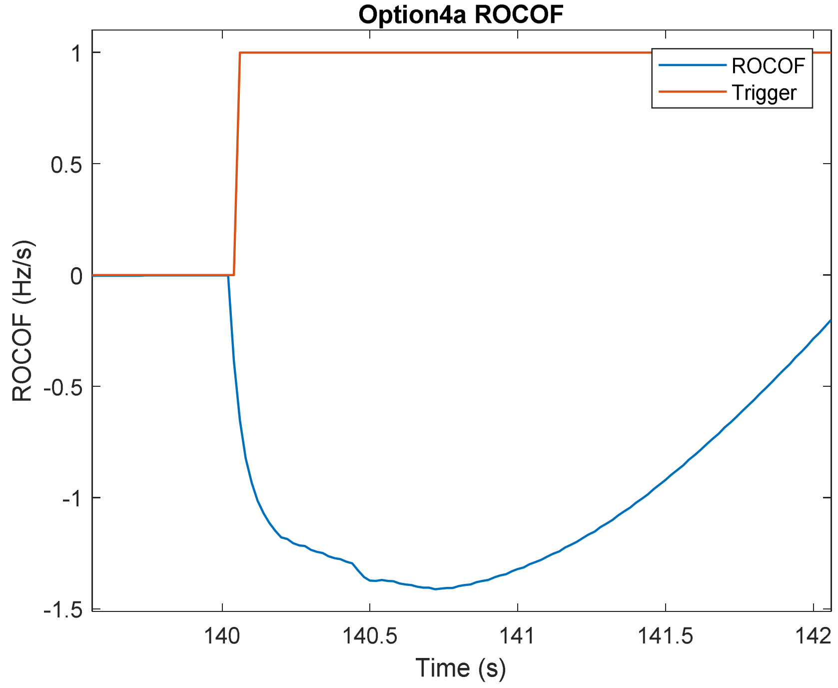
B.1.4 Restoration Option 4a

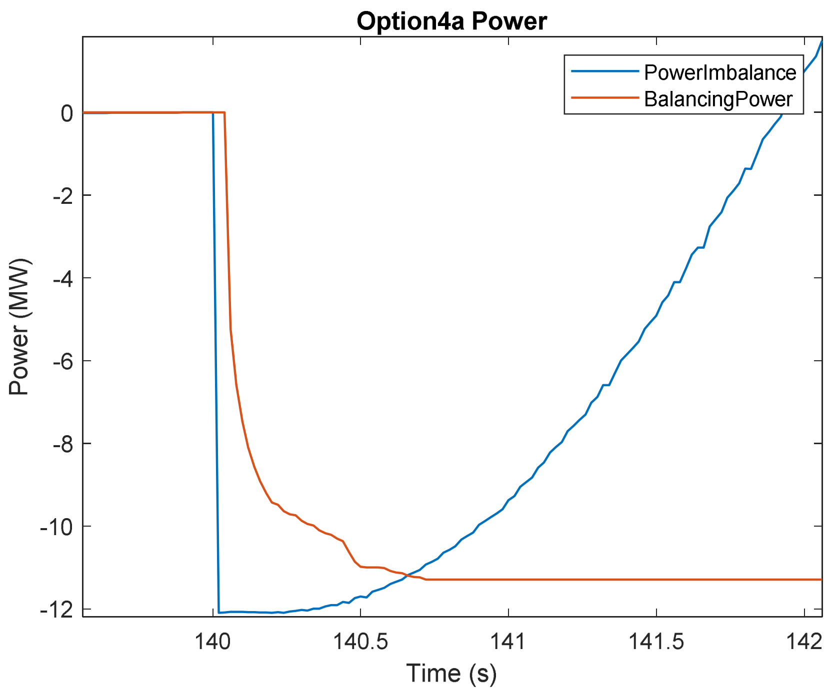


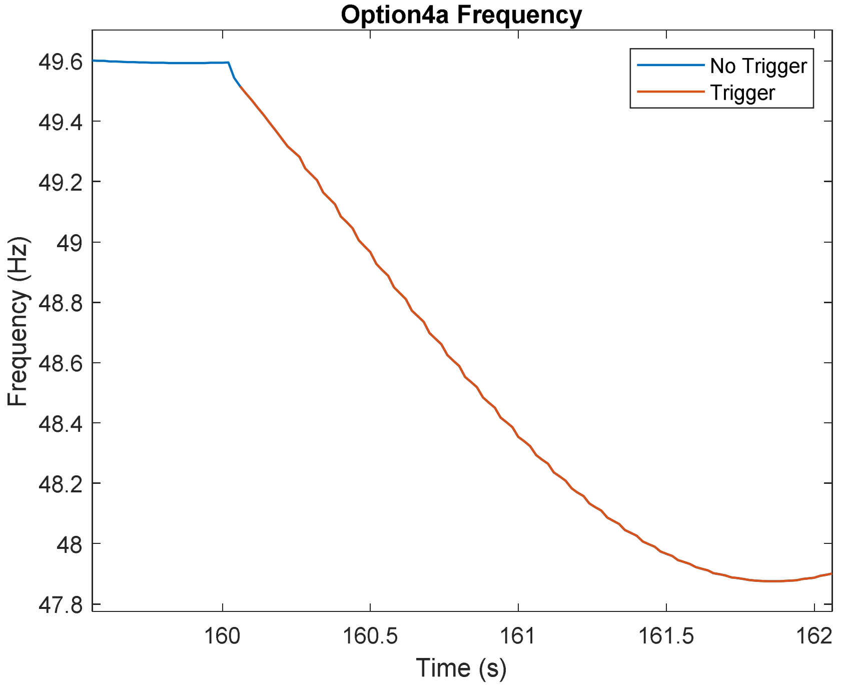


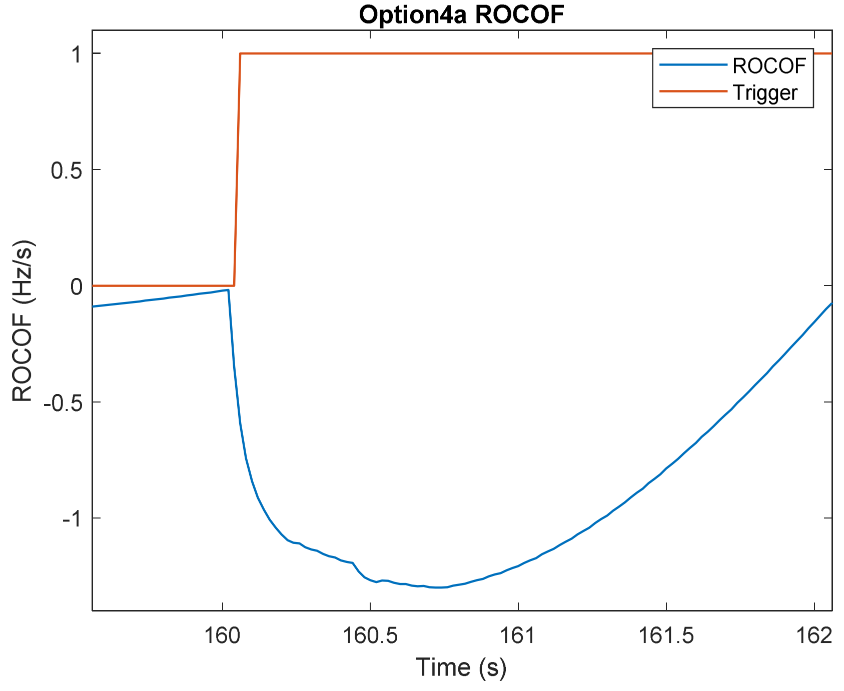

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
8
6
4
2
0
-2
-4
-6
-8
-10
-12
0
100
200
300
400
500
600

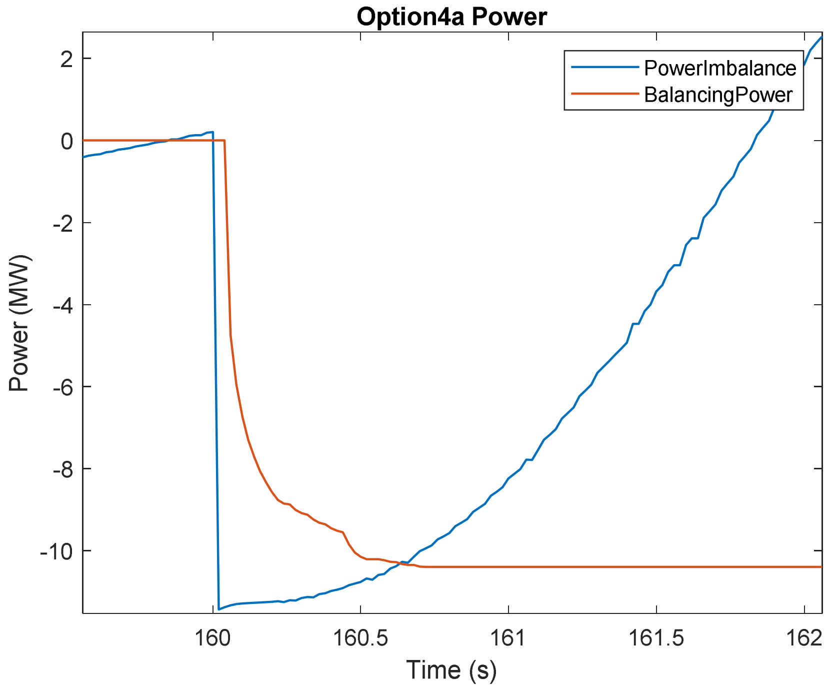

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
140
140.5
141
141.5
142

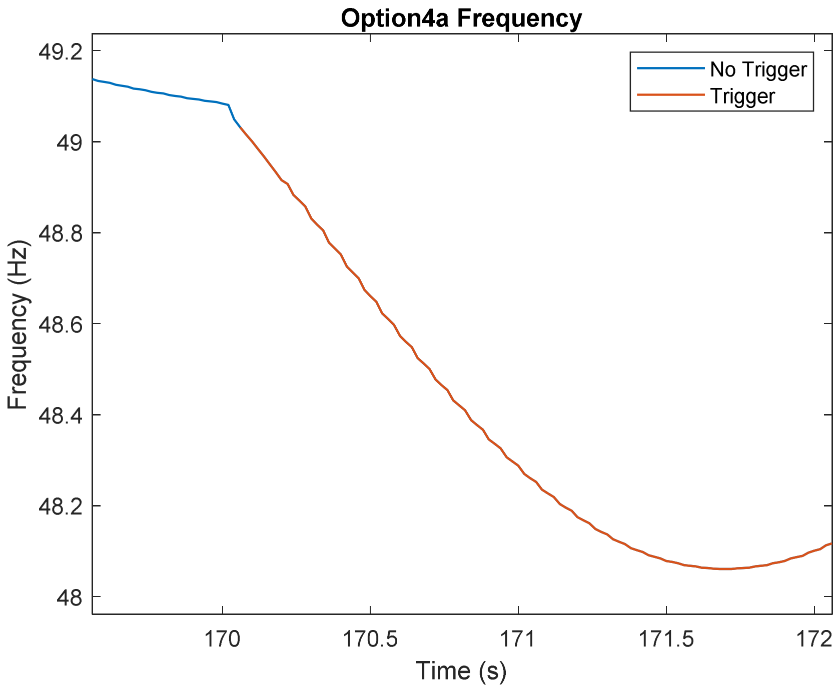

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
140
140.5
141
141.5
142
Time (s)

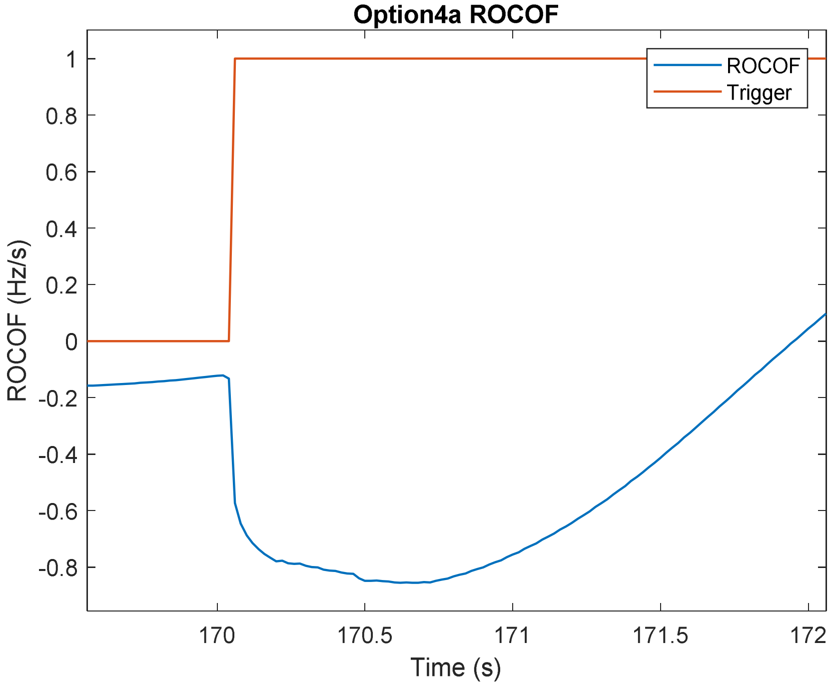

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
140
140.5
141
141.5
142
Time (s)

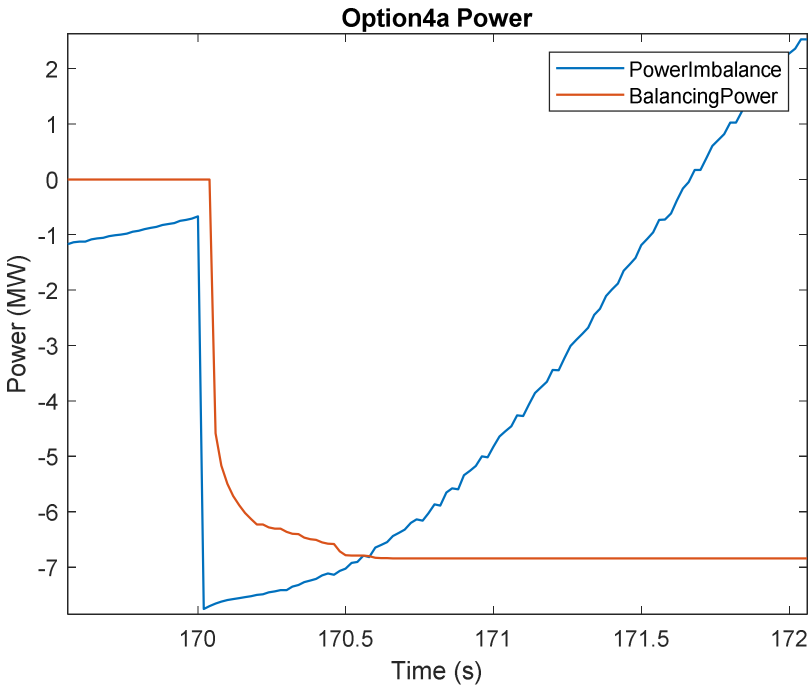

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
47.8
160
160.5
161
161.5
162
Time (s)

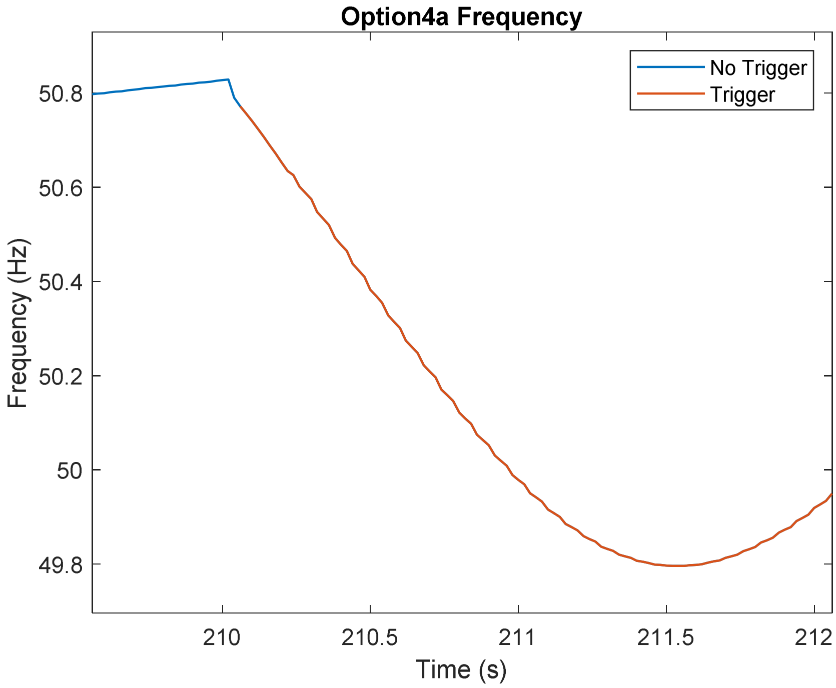

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
160
160.5
161
161.5
162
Time (s)

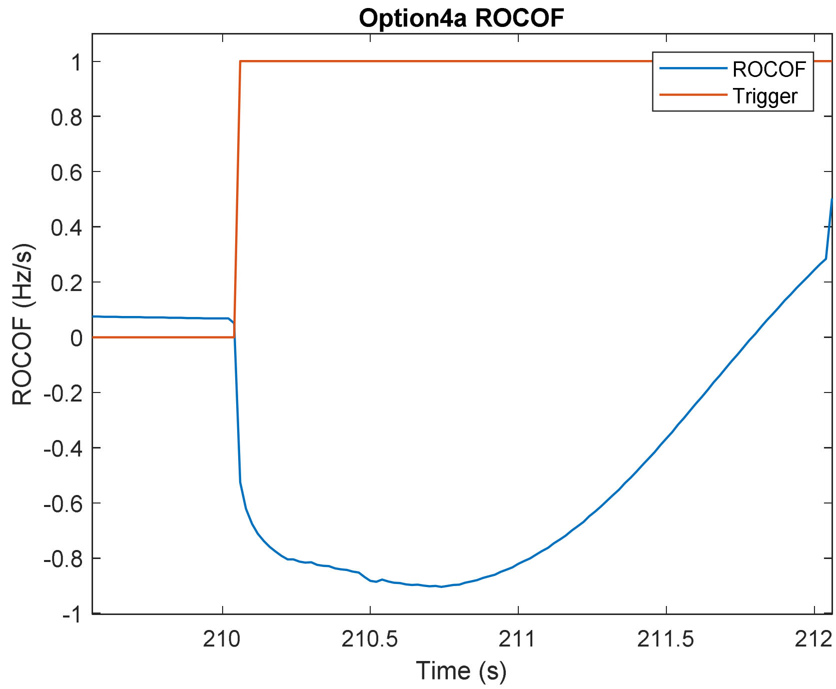

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162
Time (s)

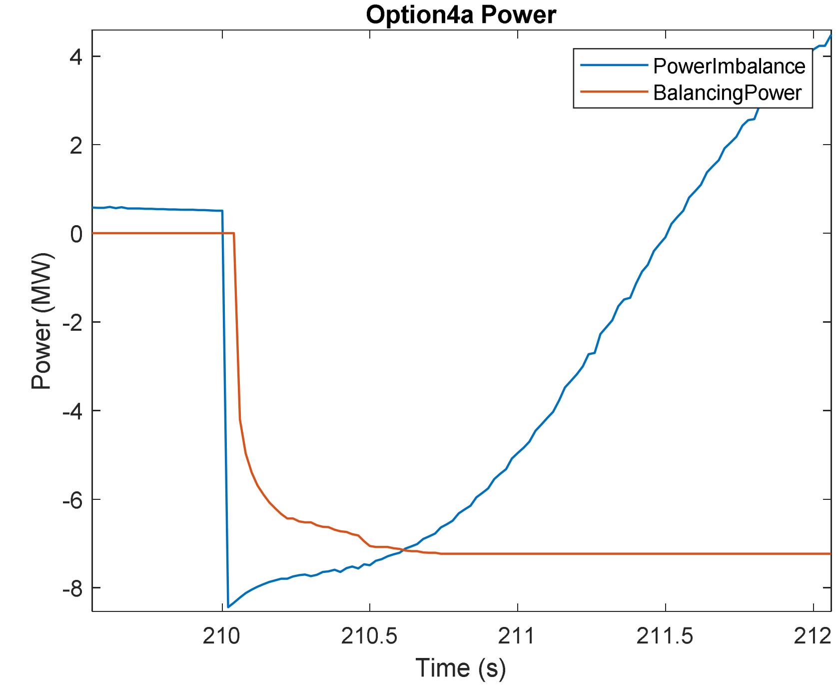

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
49.2
49
48.8
48.6
48.4
48.2
48
170
170.5
171
171.5
172
Time (s)

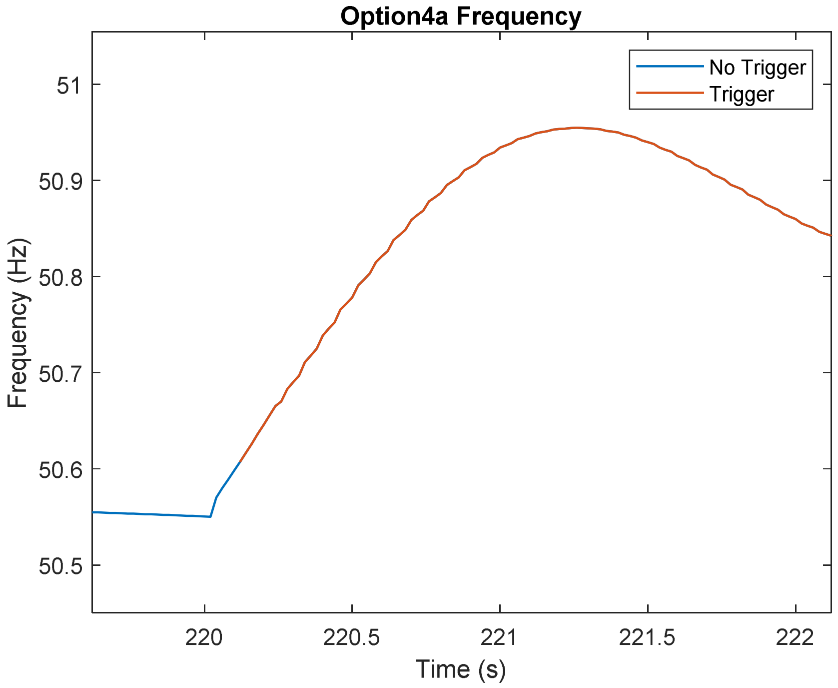

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
170
170.5
171
171.5
172
Time (s)

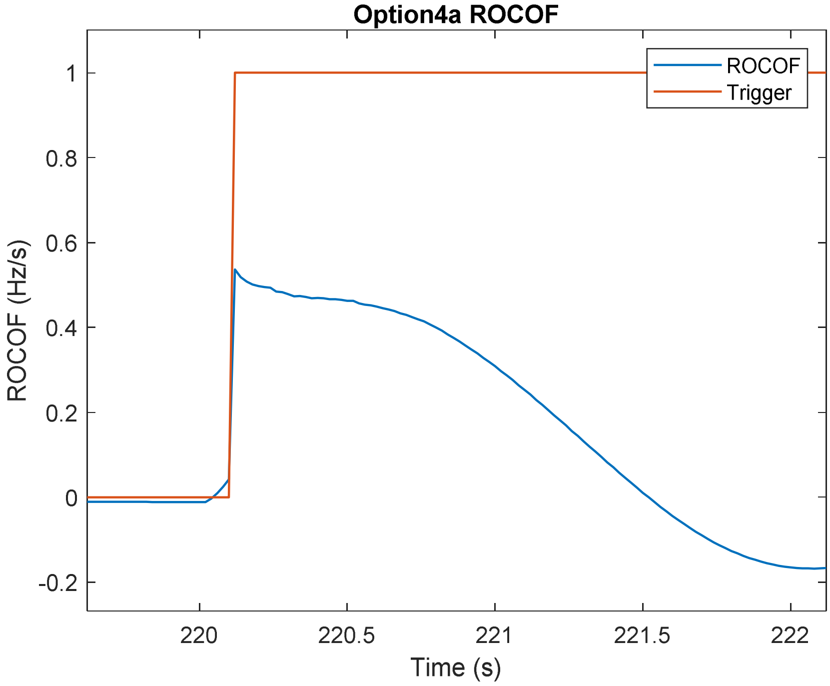

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
2
1
0
-1
-2
-3
-4
-5
-6
-7
170
170.5
171
171.5
172
Time (s)

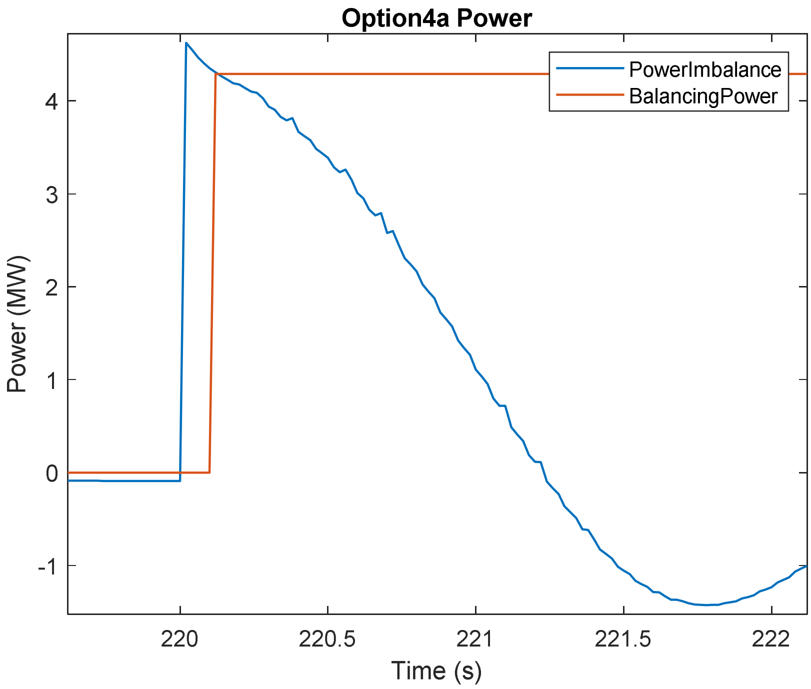

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
50.8
50.6
50.4
50.2
50
49.8
210
210.5
211
211.5
212
Time (s)

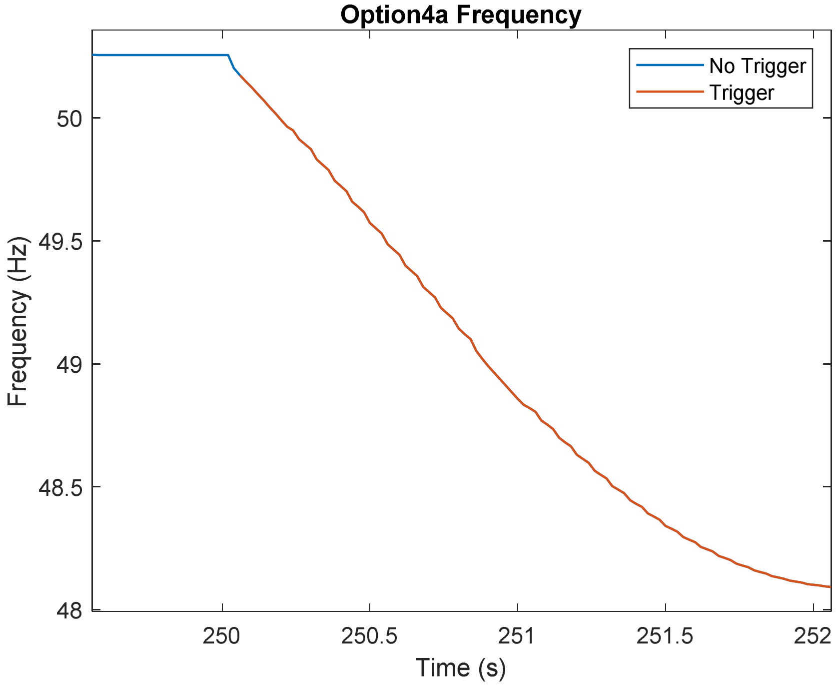

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
210
210.5
211
211.5
212
Time (s)

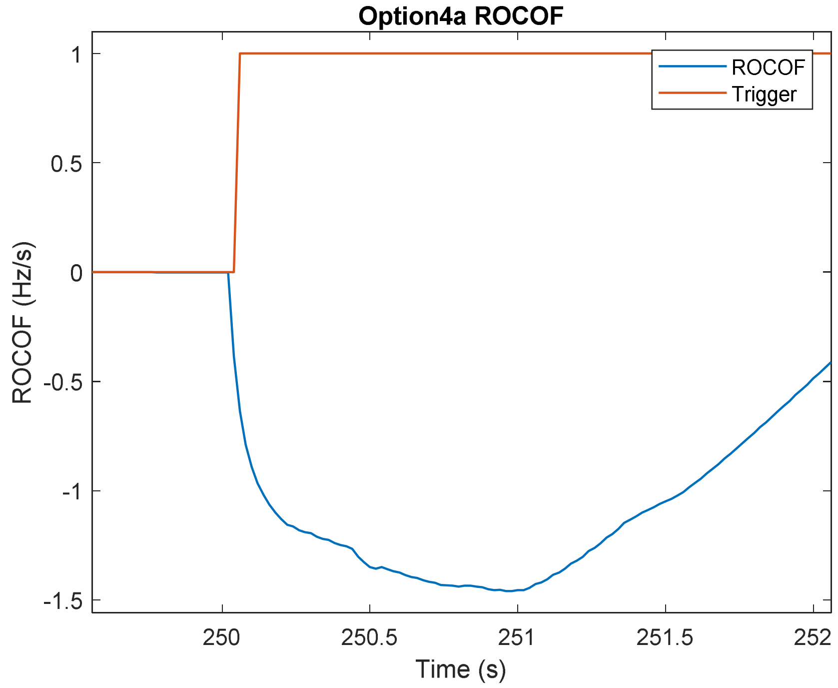

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
4
2
0
-2
-4
-6
-8
210
210.5
211
211.5
212
Time (s)

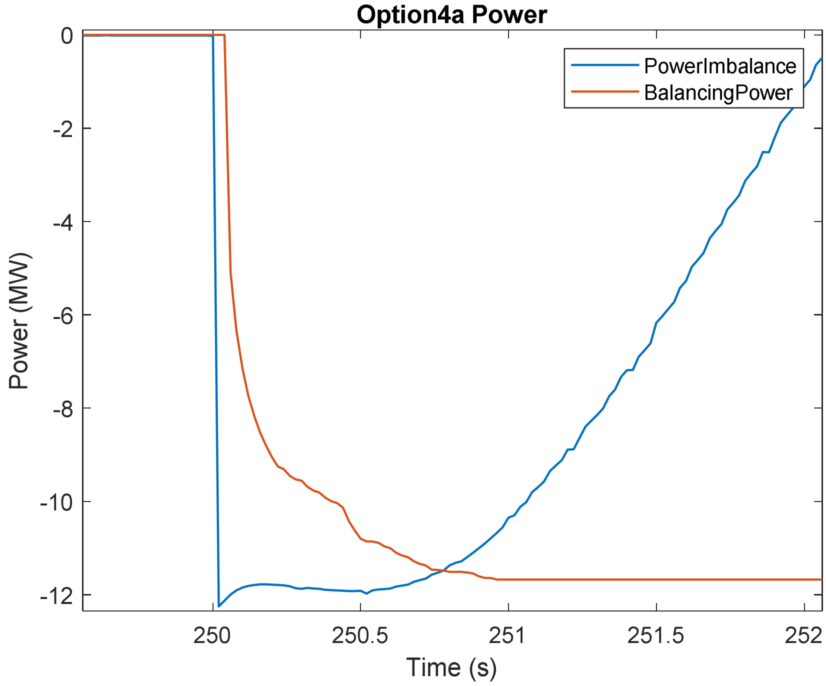

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.9
50.8
50.7
50.6
50.5
220
220.5
221
221.5
222
Time (s)

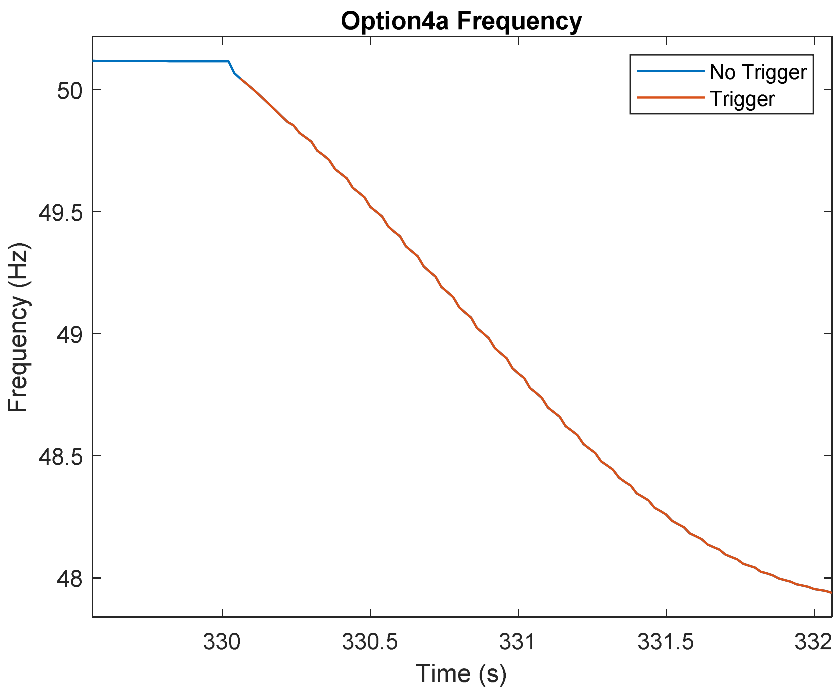

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
Time (s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222

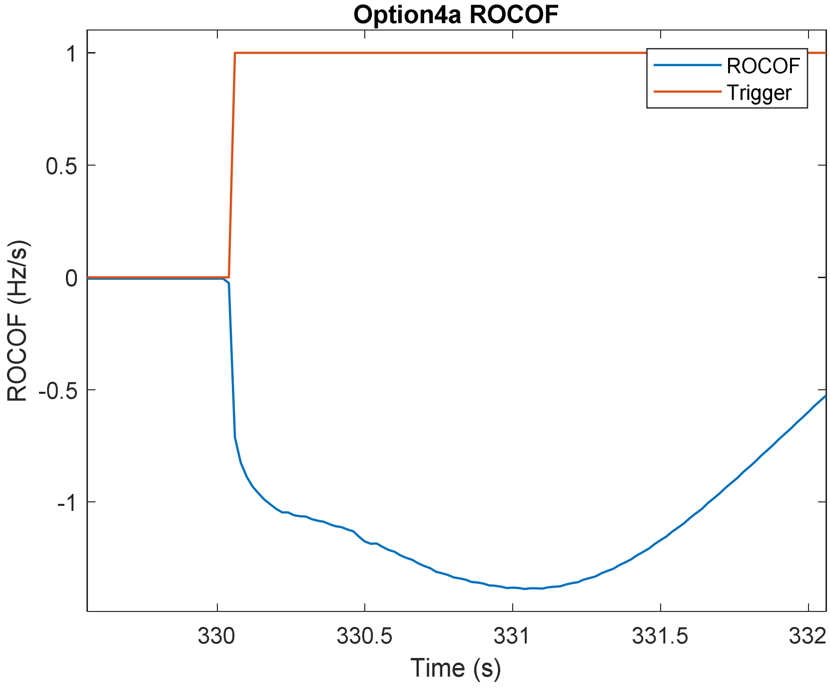

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
4
3
2
1
0
-1
220
220.5
221
221.5
222

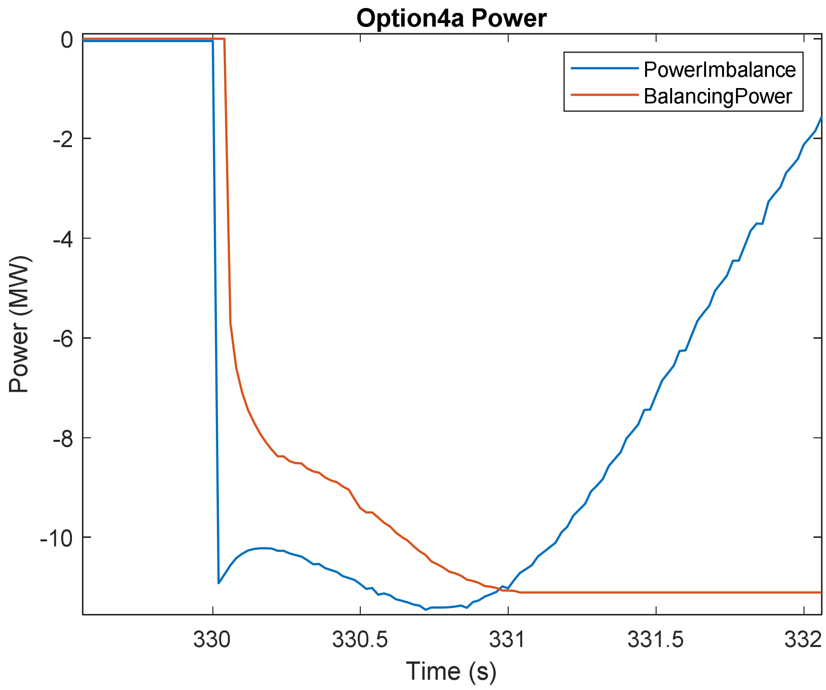

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
250
250.5
251
251.5
252
Time (s)

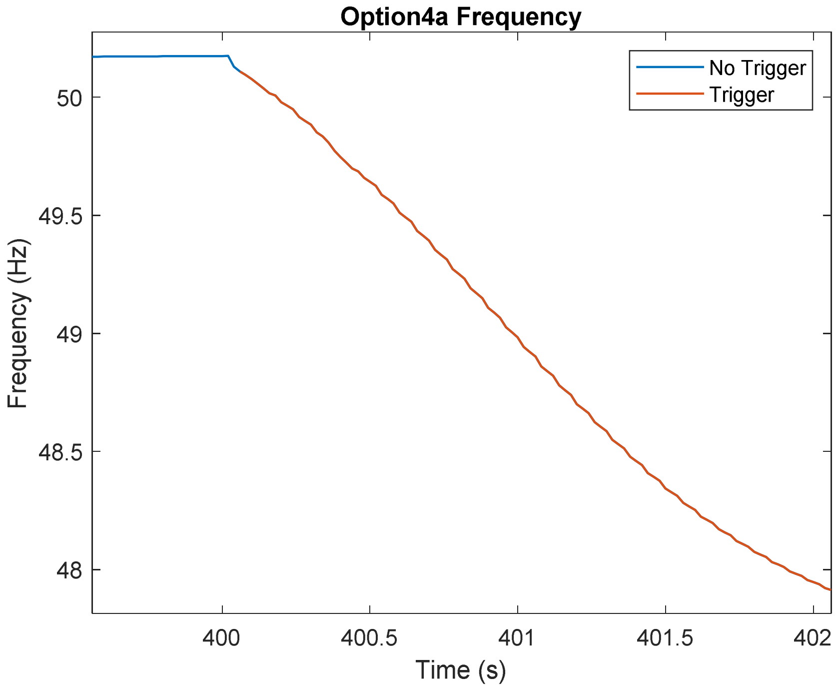

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
250
250.5
251
251.5
252
Time (s)

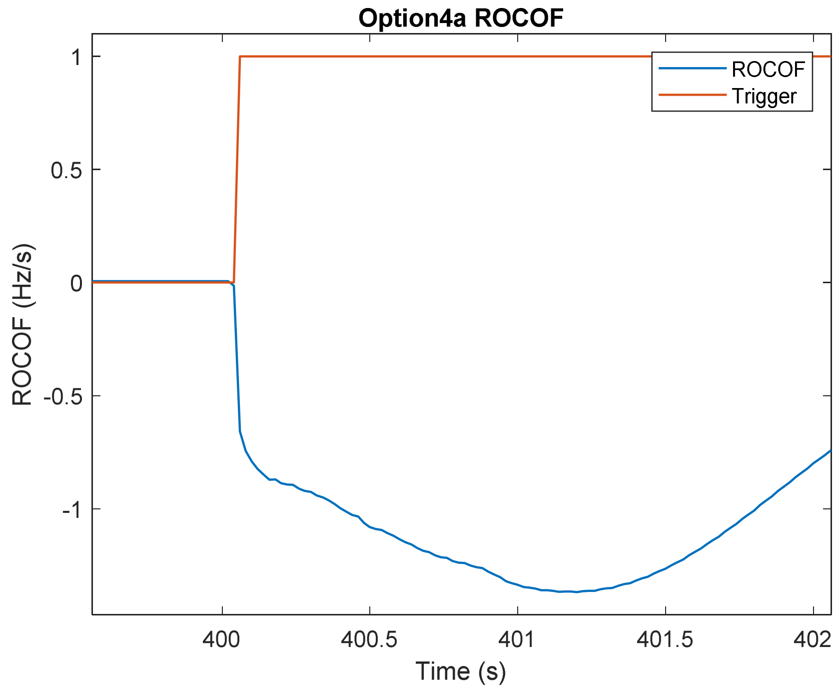

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
250
250.5
251
251.5
252
Time (s)

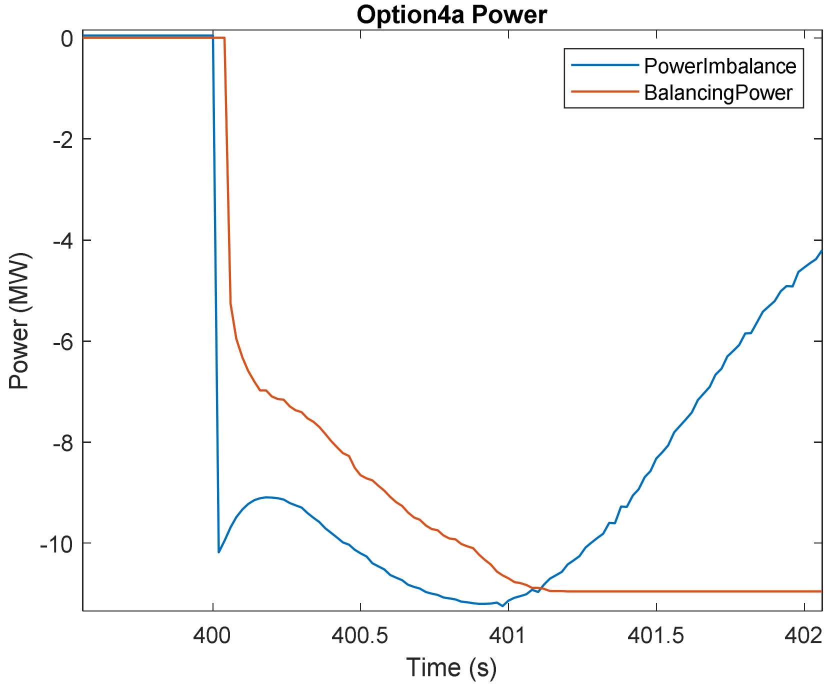

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
330
330.5
331
331.5
332
Time (s)

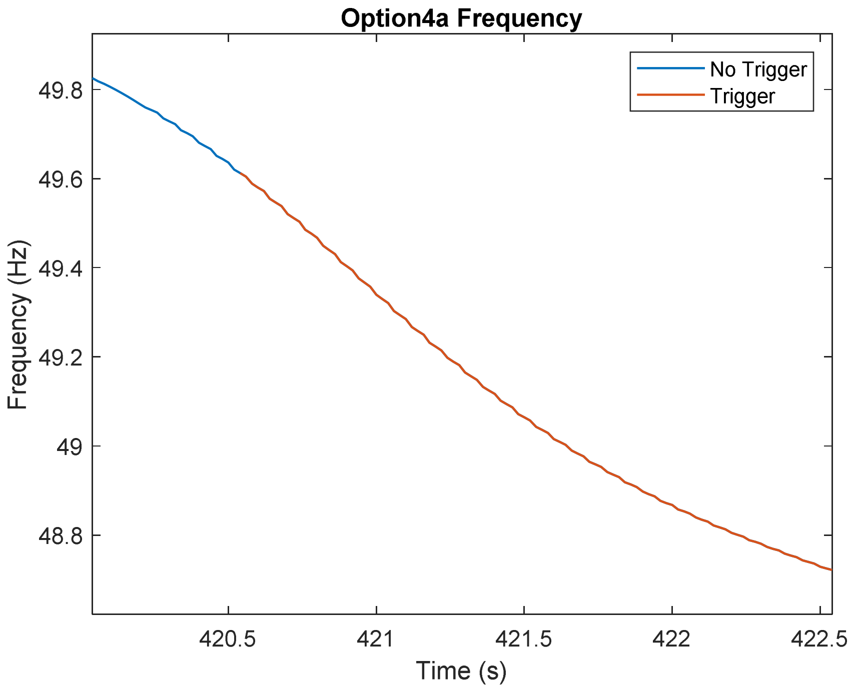

Option4a ROCOF
ROCOF (Hz/s)
Time (s)
ROCOF
Trigger
1
0.5
0
-0.5
-1
330
330.5
331
331.5
332

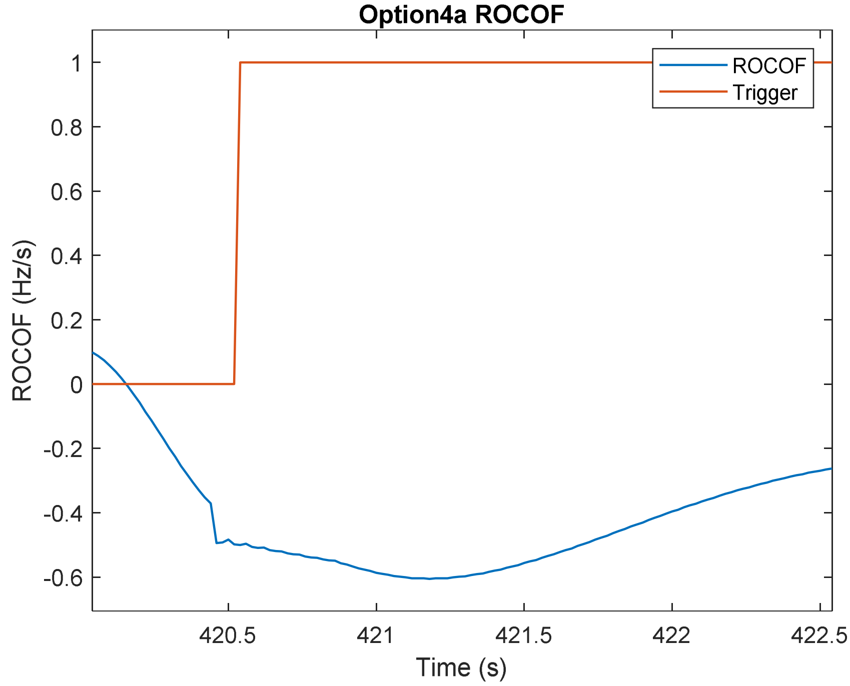

Option4a Power
Power (MW)
Time (s)
PowerImbalance
BalancingPower
0
-2
-4
-6
-8
-10
330
330.5
331
331.5
332

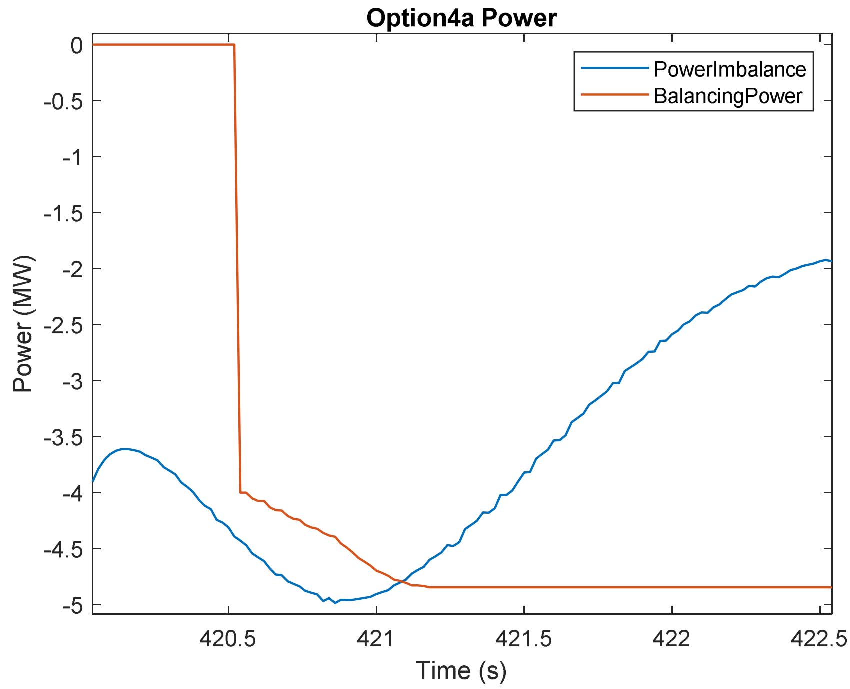

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
400
400.5
401
401.5
402
Time (s)

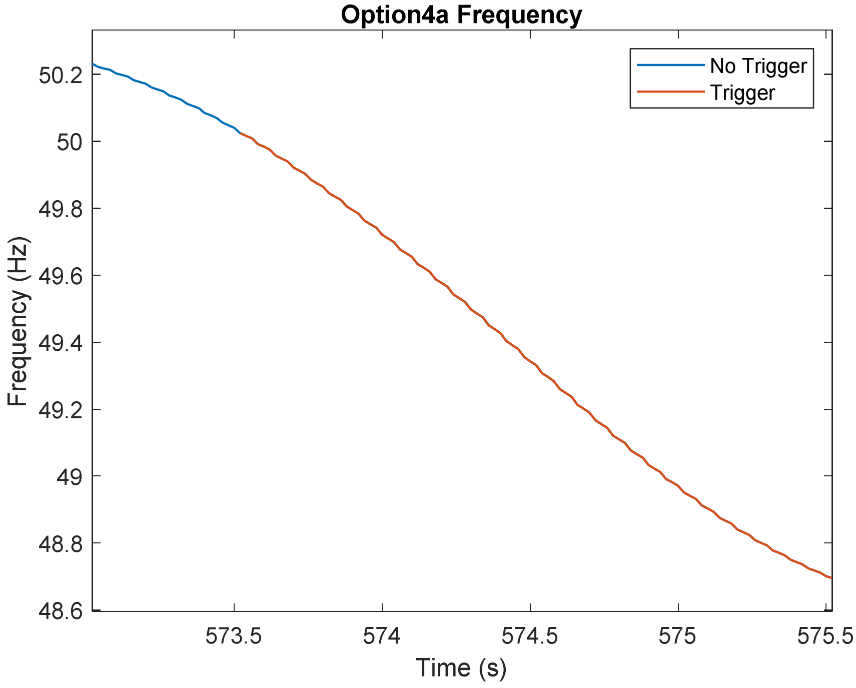

Option4a ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
400
400.5
401
401.5
402
Time (s)

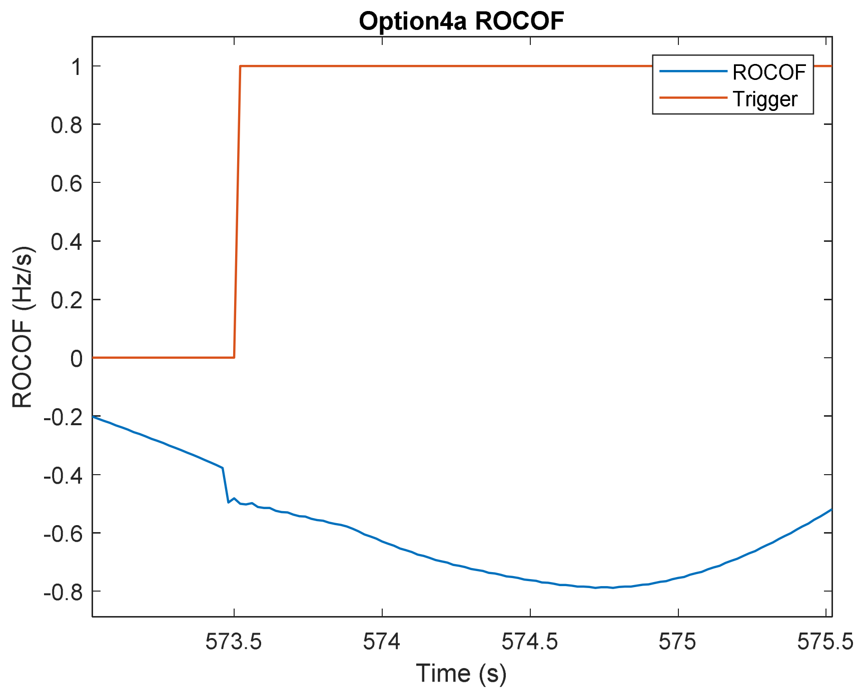

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
400
400.5
401
401.5
402
Time (s)

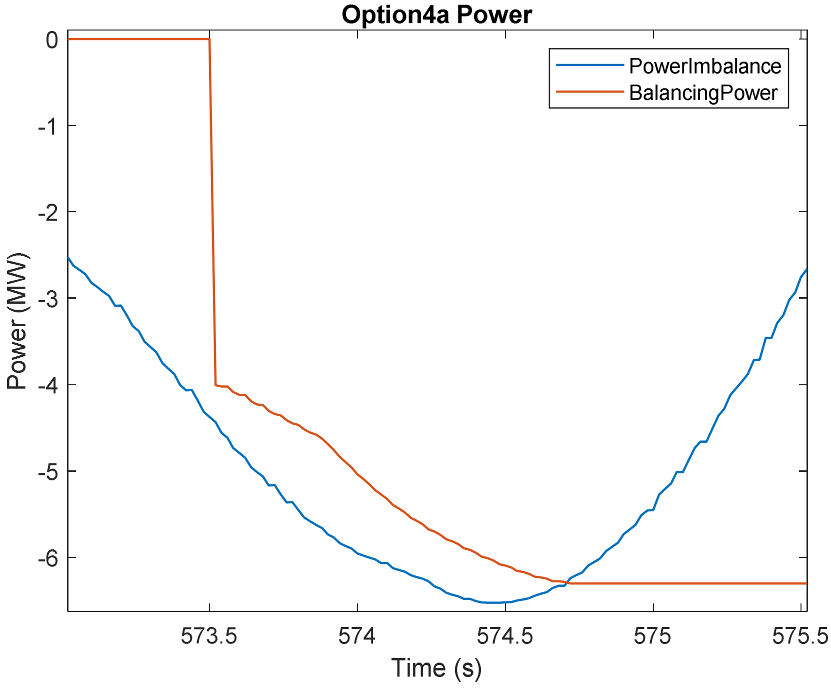

Option4a Frequency
No Trigger
Trigger
Frequency (Hz)
49.8
49.6
49.4
49.2
49
48.8
420.5
421
421.5
422
422.5
Time (s)


Option4a ROCOF
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
420.5
421
421.5
422
422.5
Time (s)
ROCOF
Trigger

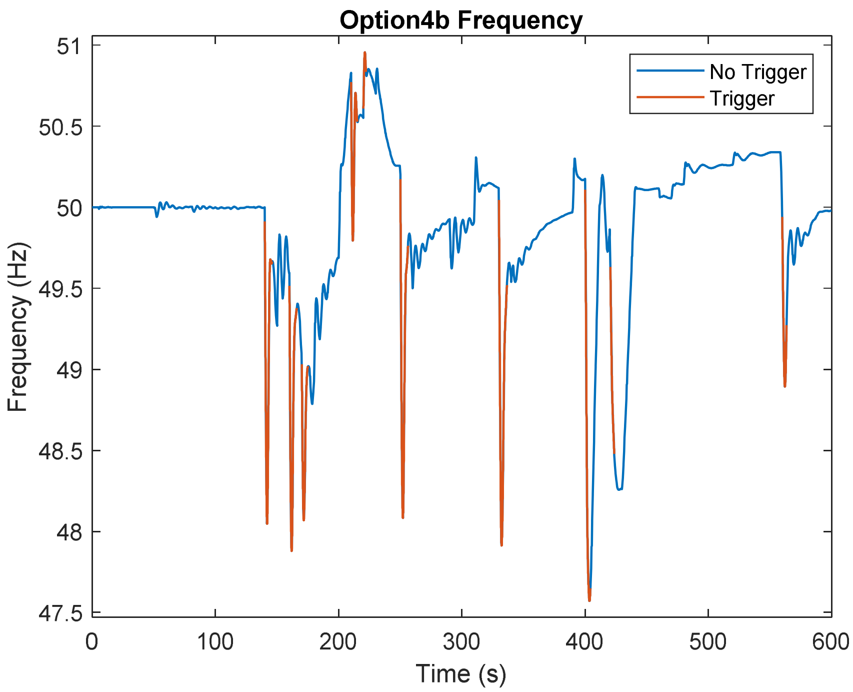

Option4a Power
Power (MW)
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
-5
420.5
421
421.5
422
422.5
Time (s)
PowerImbalance
BalancingPower

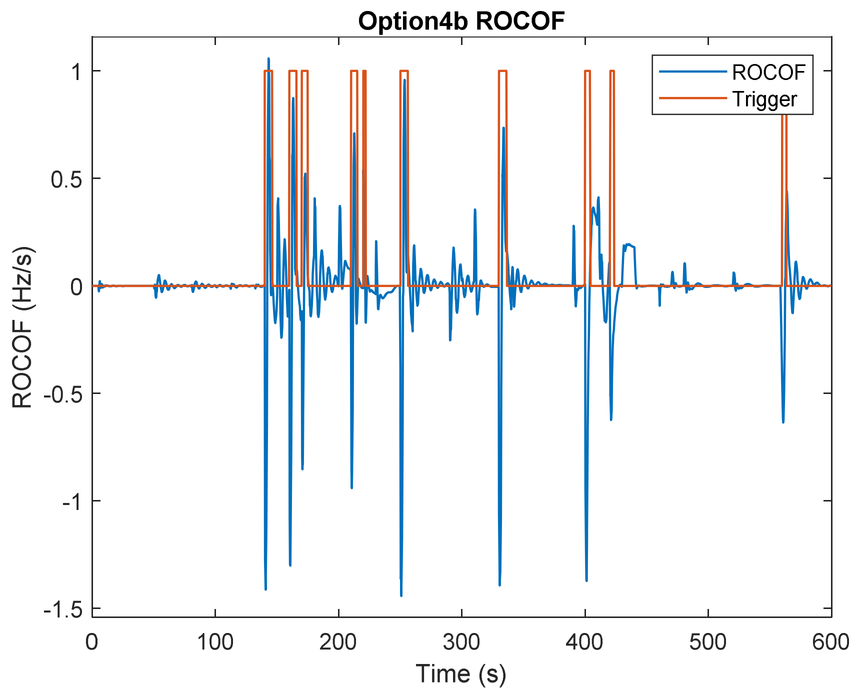

Option4a Frequency
No Trigger
Trigger
50.2
50
49.8
49.6
49.4
49.2
49
48.8
48.6
Frequency (Hz)
573.5
574
574.5
575
575.5
Time (s)

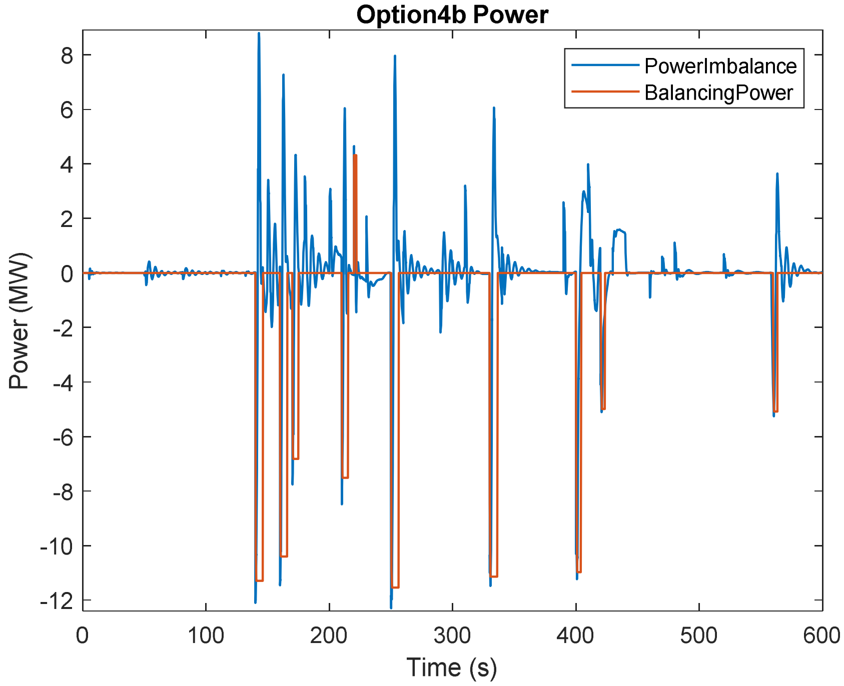

Option4a ROCOF
ROCOF
Trigger
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
ROCOF (Hz/s)
573.5
574
574.5
575
575.5
Time (s)

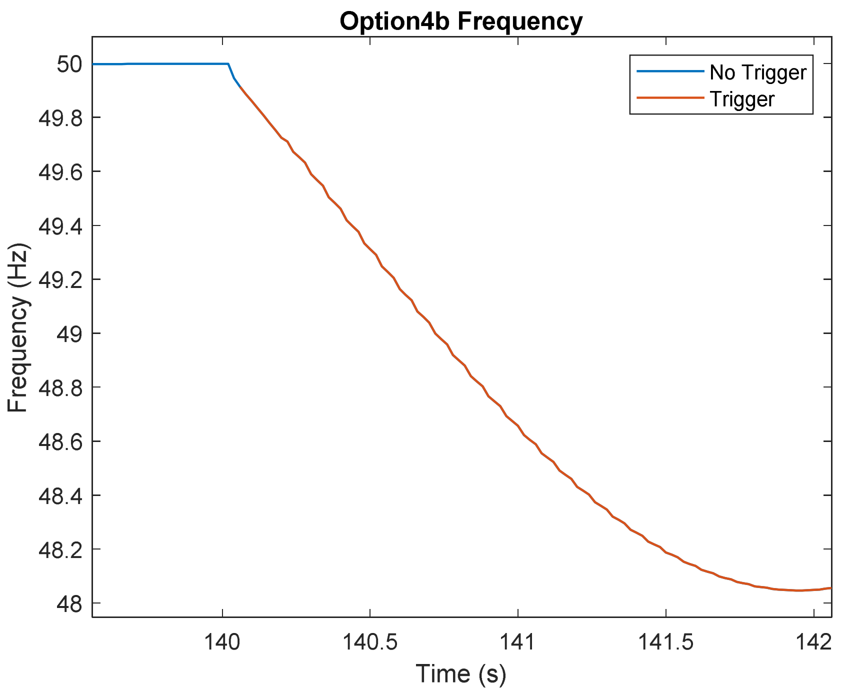

Option4a Power
PowerImbalance
BalancingPower
Power (MW)
0
-1
-2
-3
-4
-5
-6
573.5
574
574.5
575
575.5
Time (s)

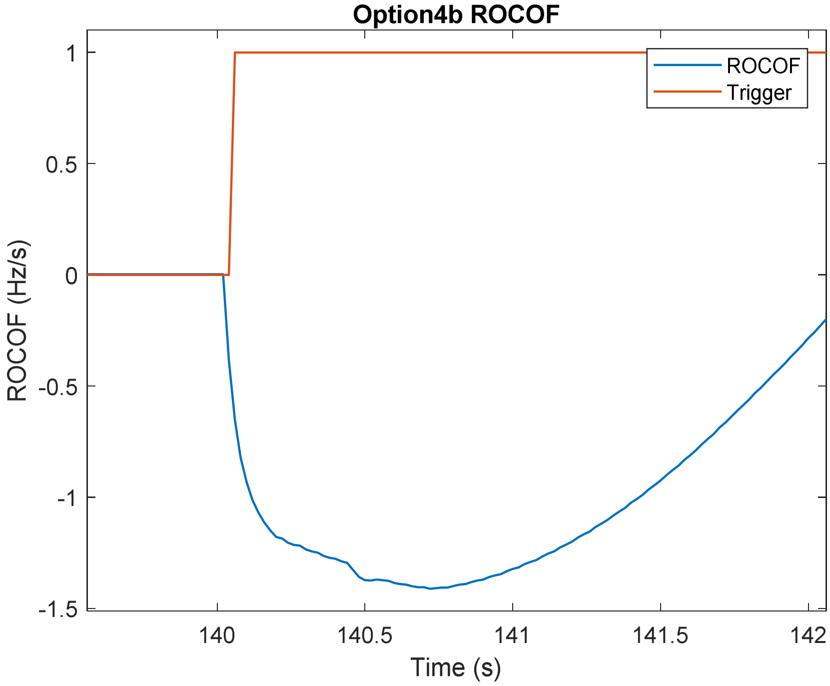
B.1.5 Restoration Option 4b

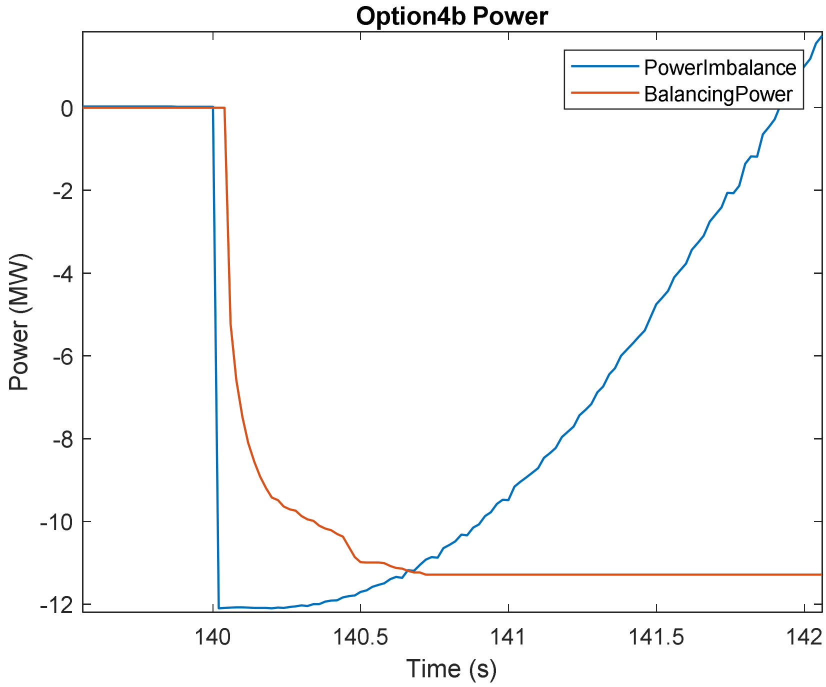


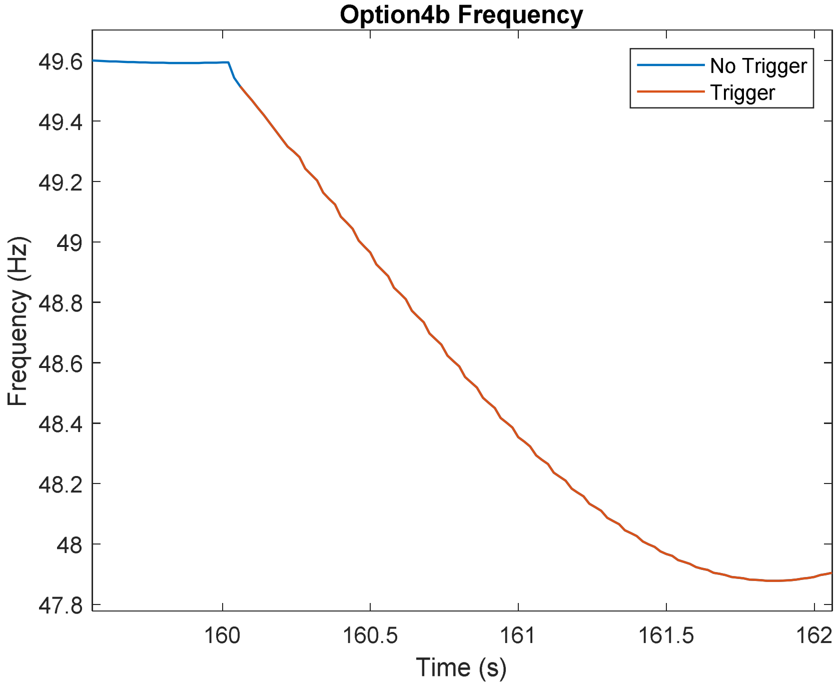


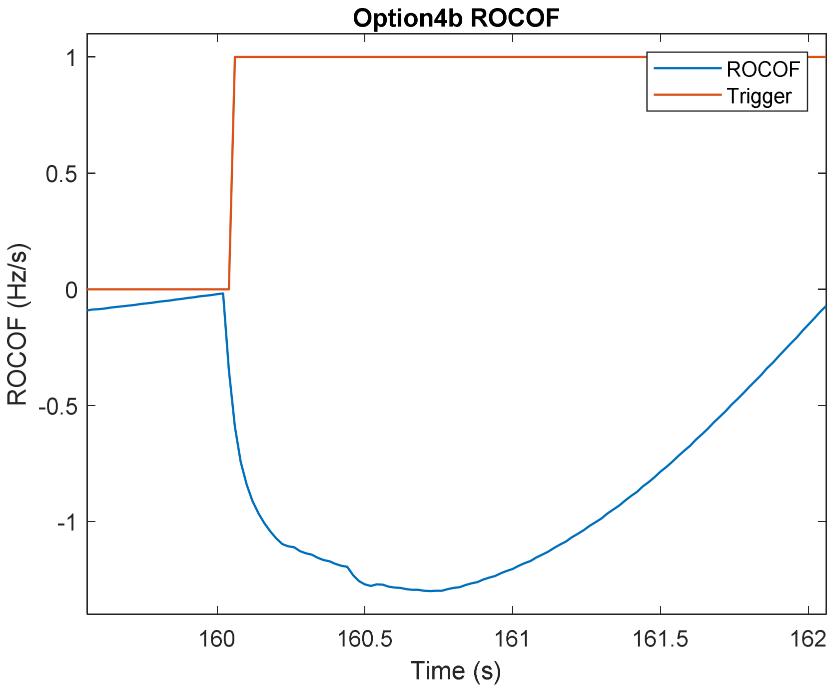

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
8
6
4
2
0
-2
-4
-6
-8
-10
-12
0
100
200
300
400
500
600

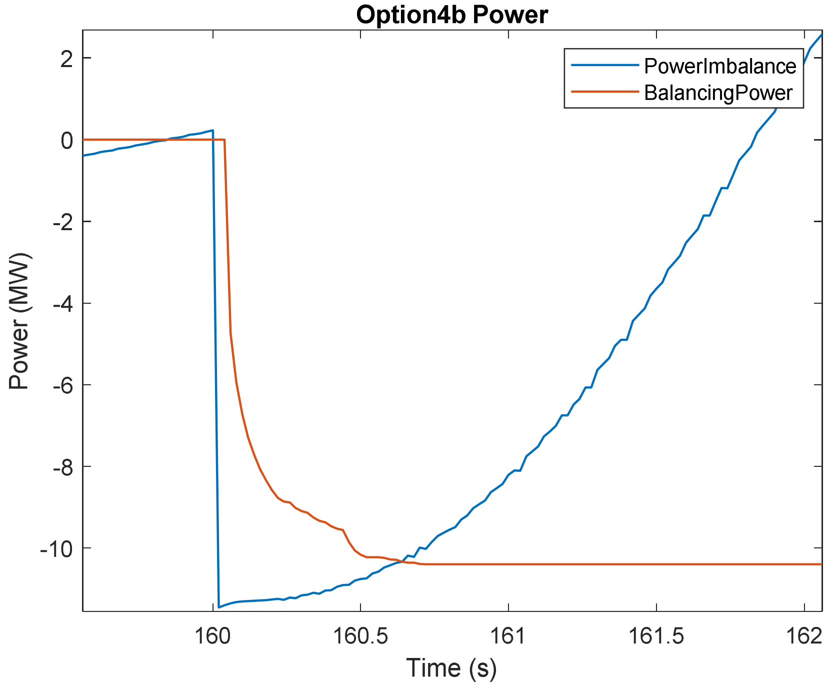

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
140
140.5
141
141.5
142

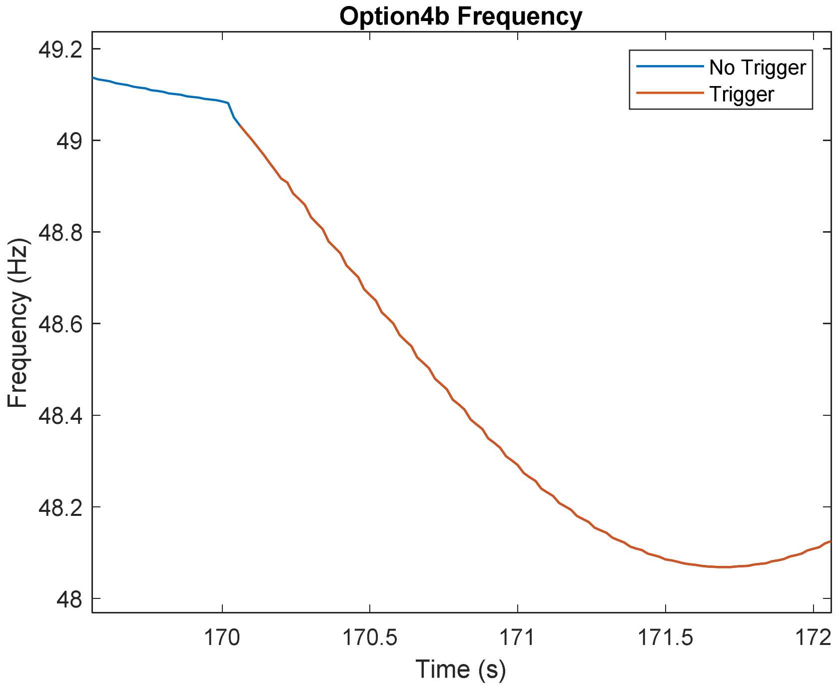

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
140
140.5
141
141.5
142
Time (s)

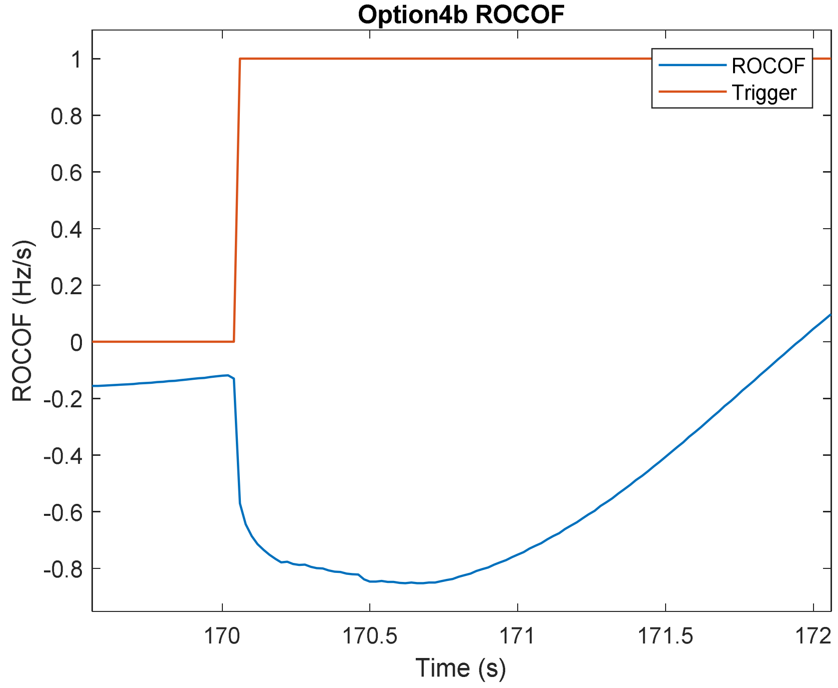

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
140
140.5
141
141.5
142
Time (s)

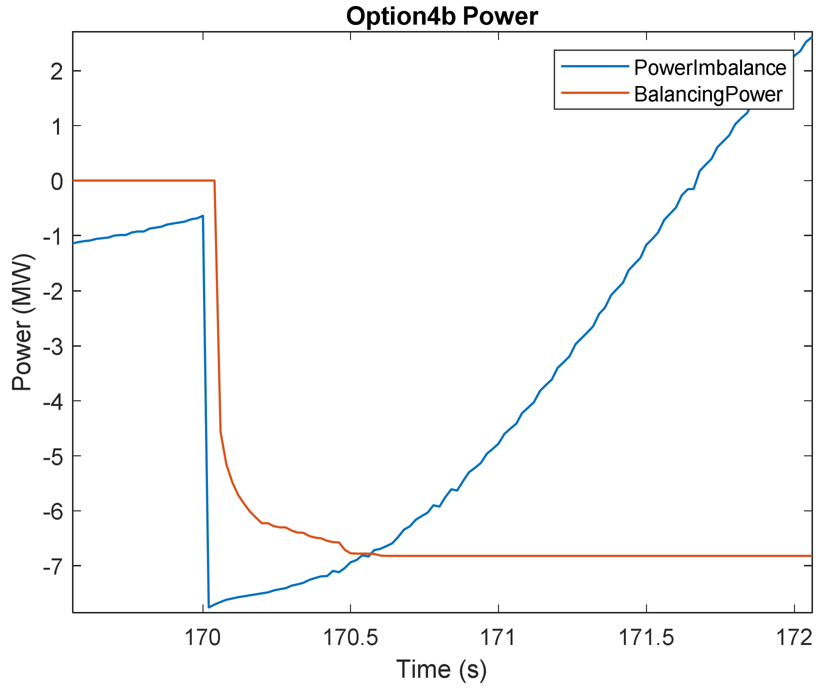

Option4b Frequency
No Trigger
Trigger
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
47.8
Frequency (Hz)
160
160.5
161
161.5
162
Time (s)

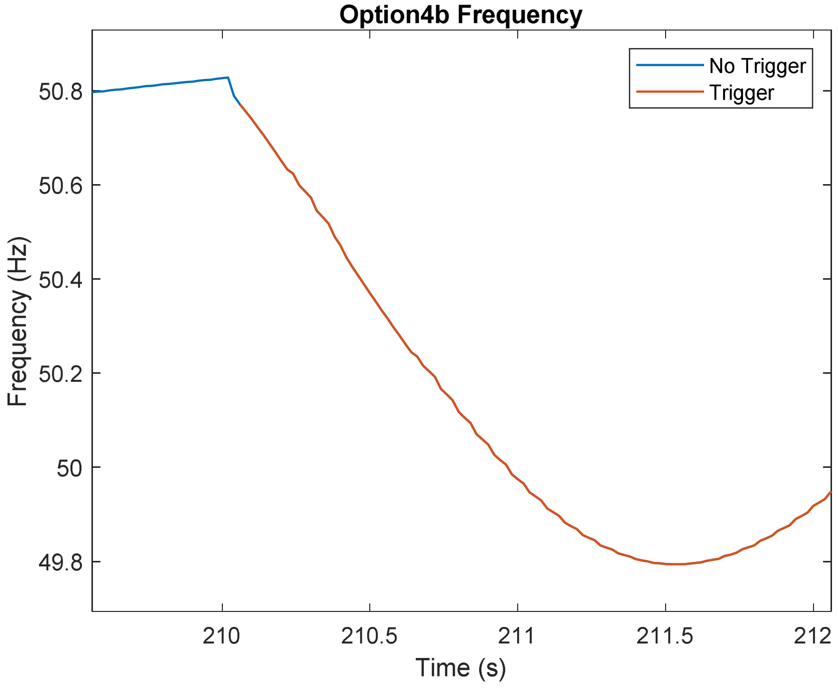

Option4b ROCOF
ROCOF
Trigger
1
0.5
0
-0.5
-1
ROCOF (Hz/s)
160
160.5
161
161.5
162
Time (s)

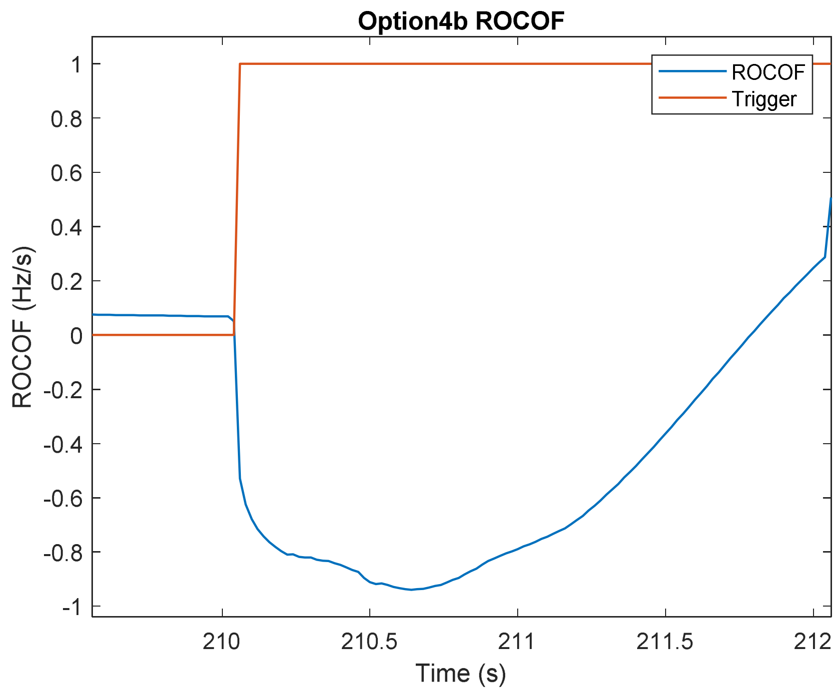

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
Time (s)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162

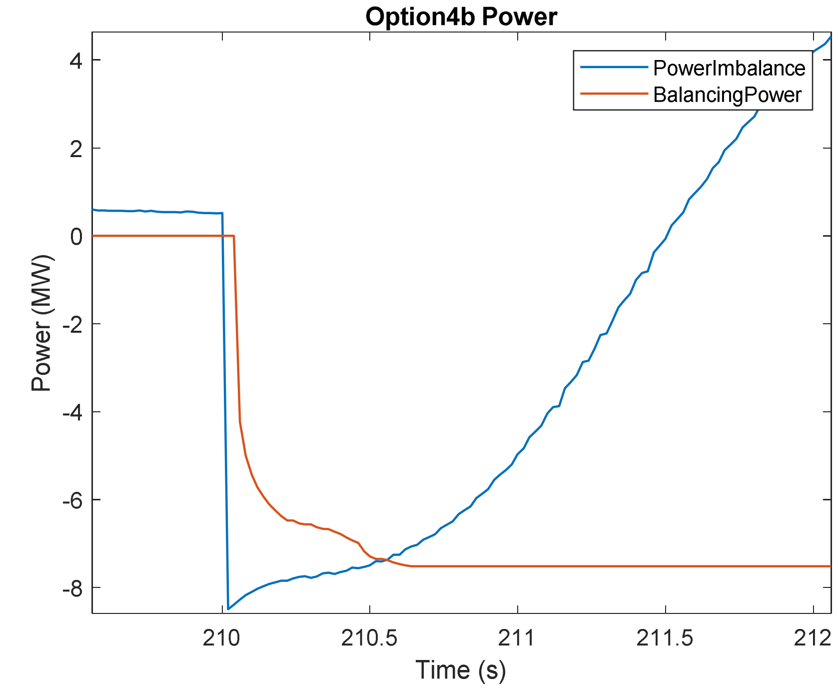

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
Time (s)
49.2
49
48.8
48.6
48.4
48.2
48
170
170.5
171
171.5
172

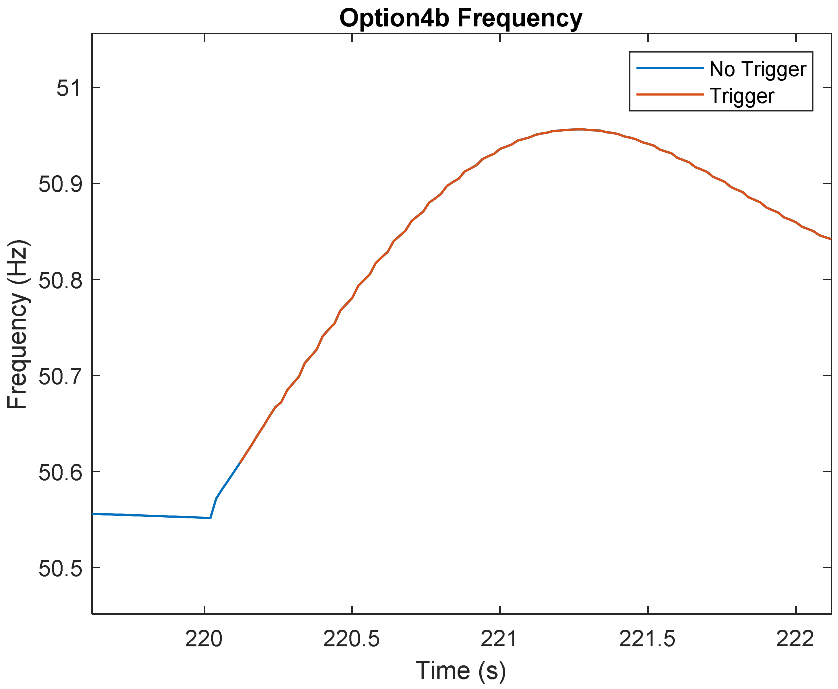

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
170
170.5
171
171.5
172
Time (s)

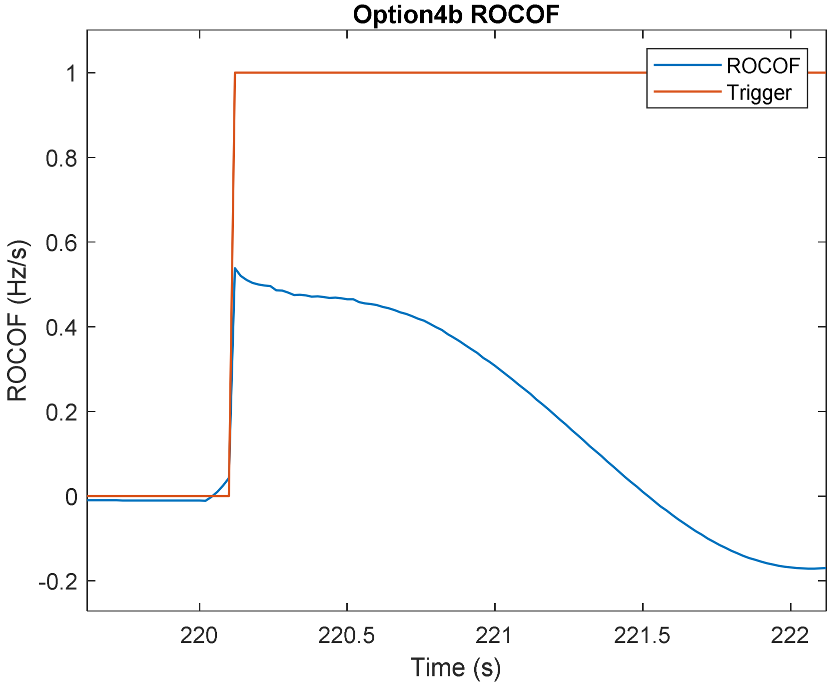

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
2
1
0
-1
-2
-3
-4
-5
-6
-7
170
170.5
171
171.5
172
Time (s)

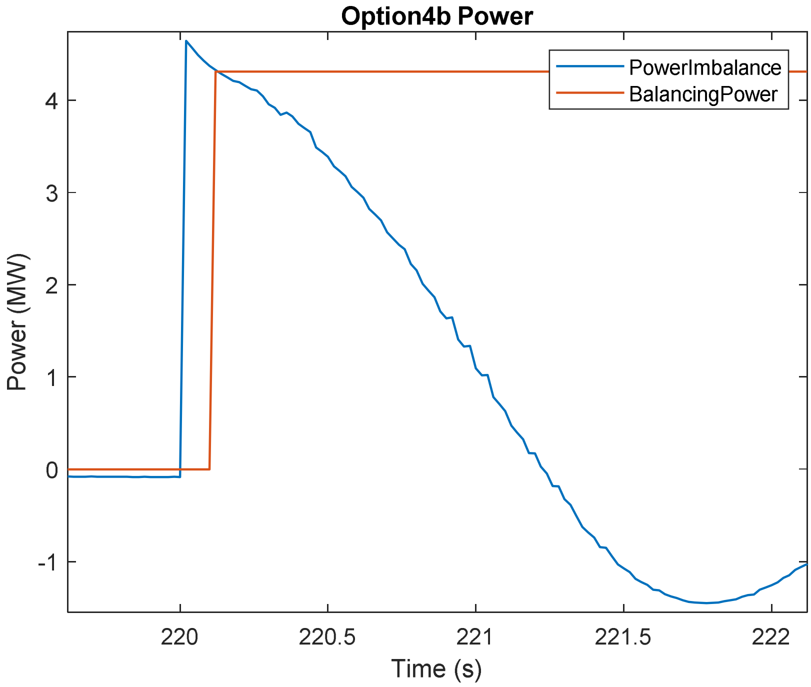

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
50.8
50.6
50.4
50.2
50
49.8
210
210.5
211
211.5
212
Time (s)

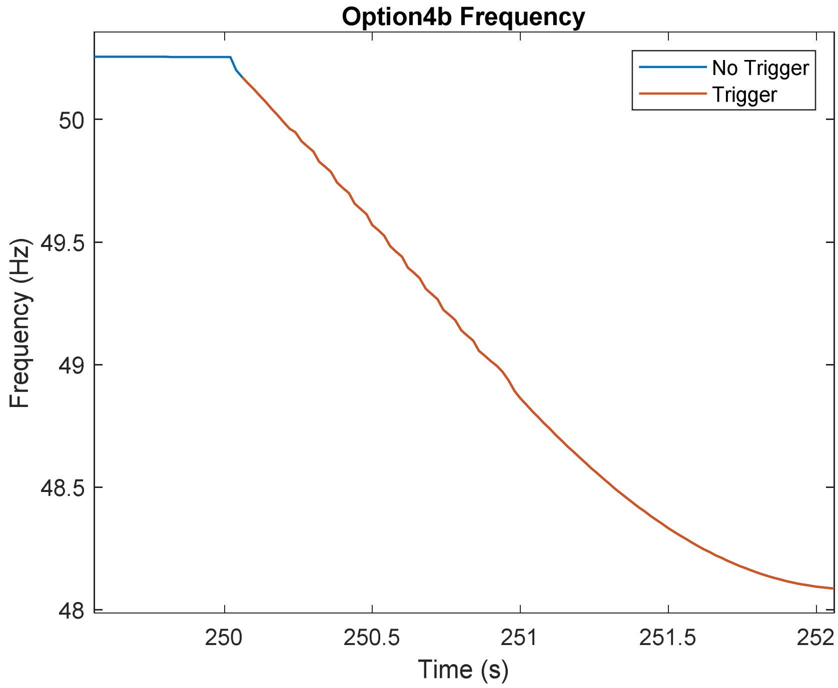

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
210
210.5
211
211.5
212
Time (s)

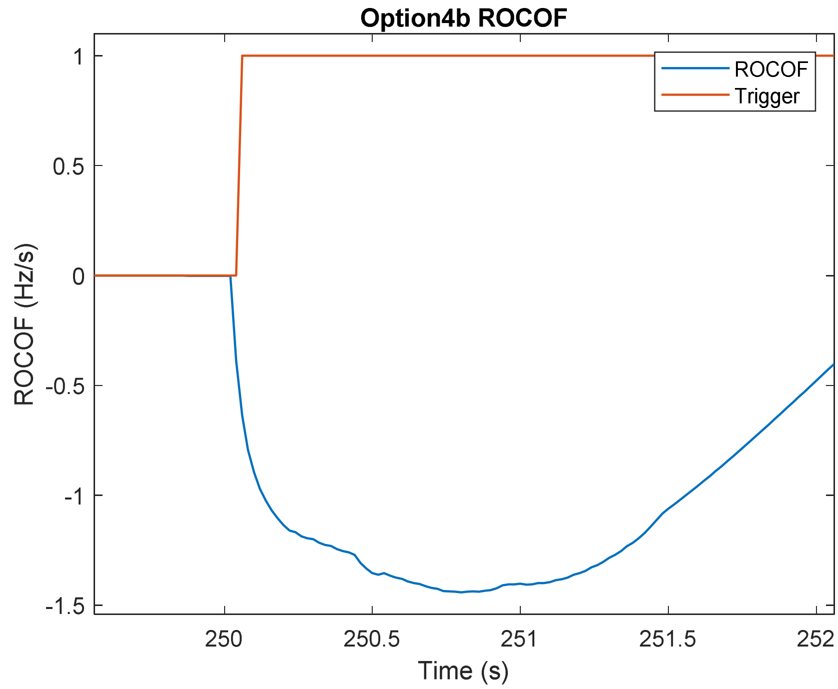

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
4
2
0
-2
-4
-6
-8
210
210.5
211
211.5
212
Time (s)

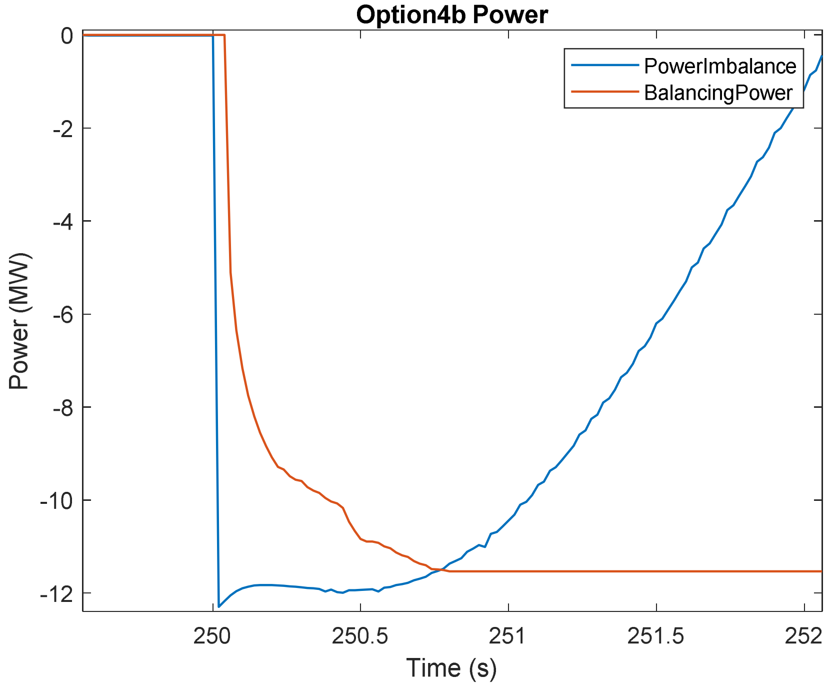

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.9
50.8
50.7
50.6
50.5
220
220.5
221
221.5
222
Time (s)

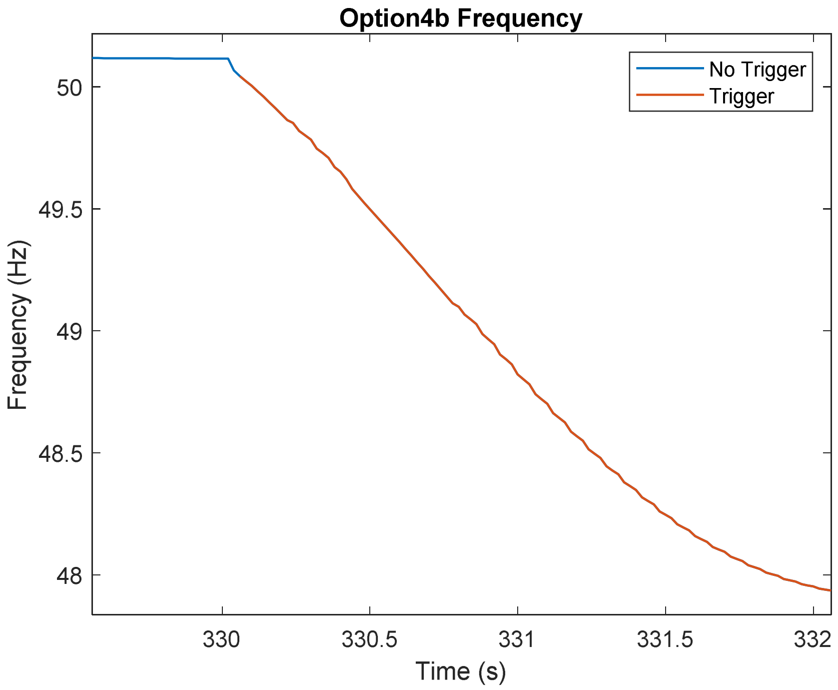

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222
Time (s)

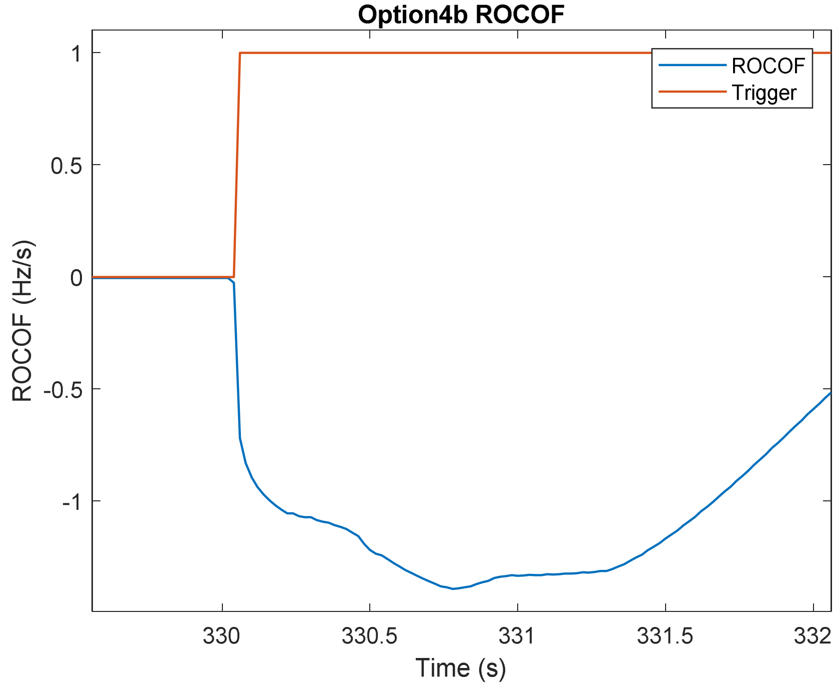

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
220
220.5
221
221.5
222
Time (s)

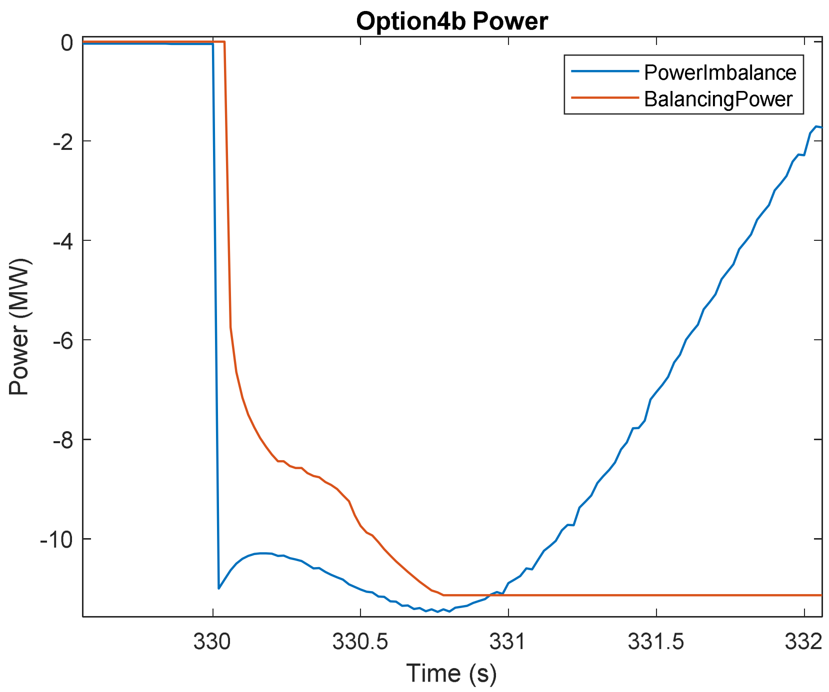

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
250
250.5
251
251.5
252
Time (s)

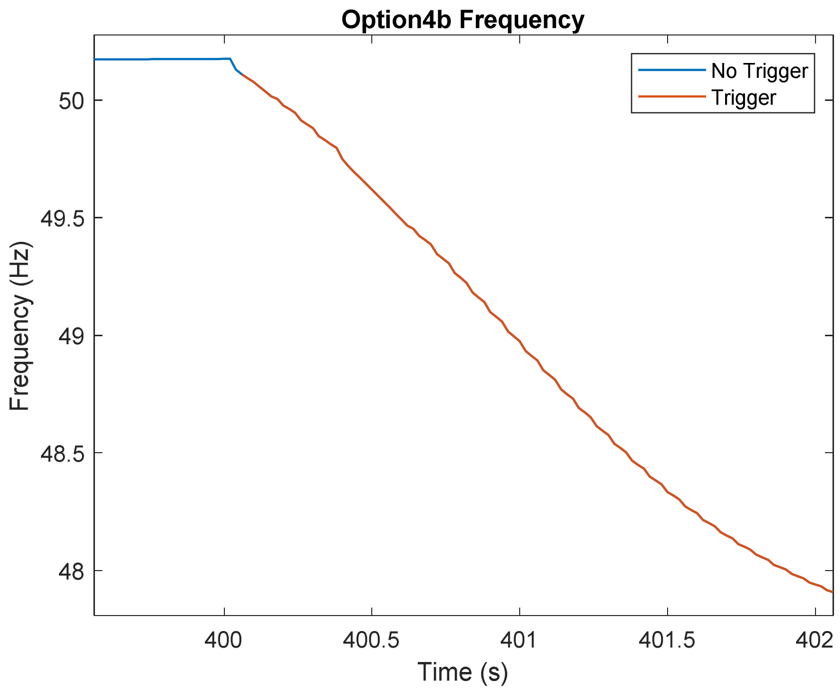

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
250
250.5
251
251.5
252
Time (s)

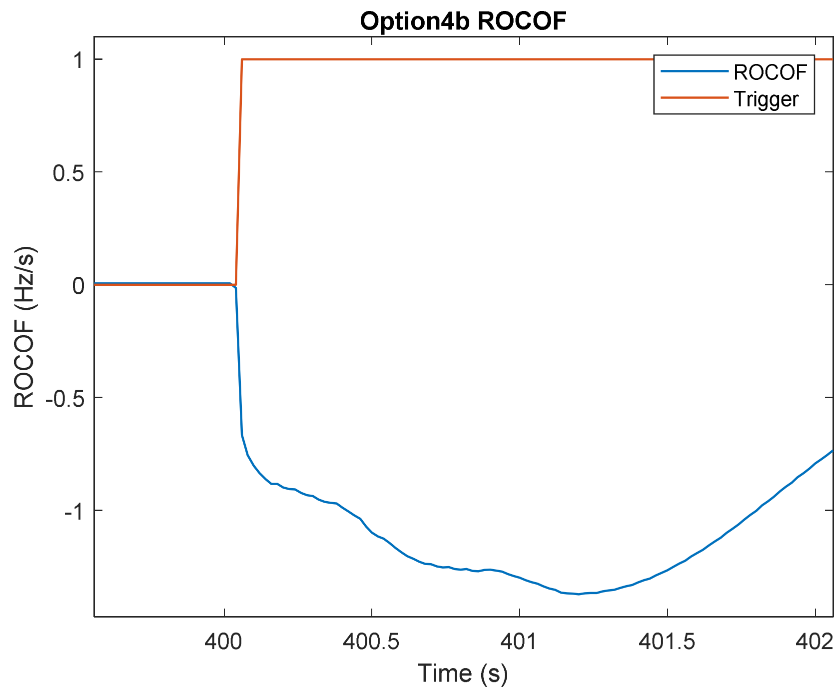

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
250
250.5
251
251.5
252
Time (s)

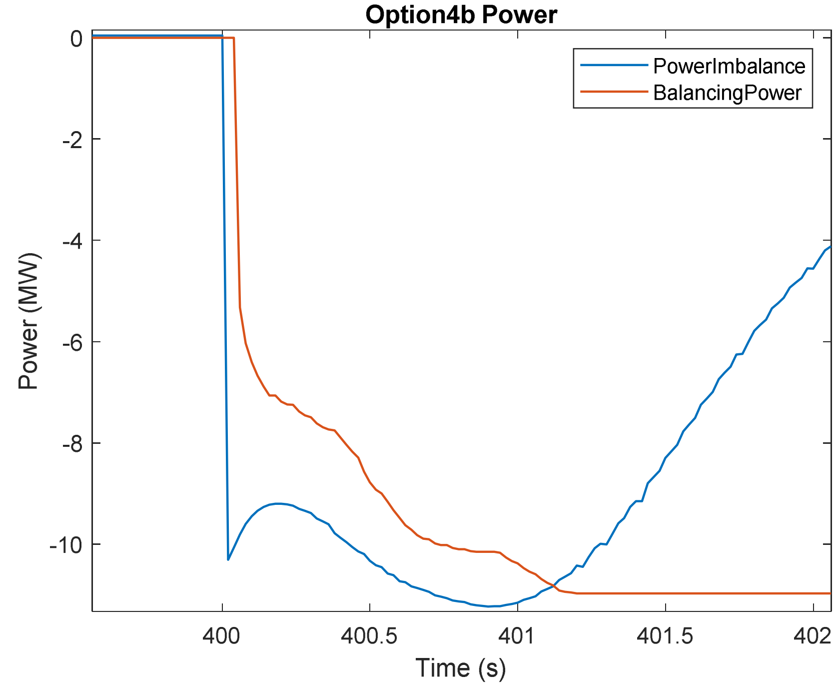

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
330
330.5
331
331.5
332
Time (s)

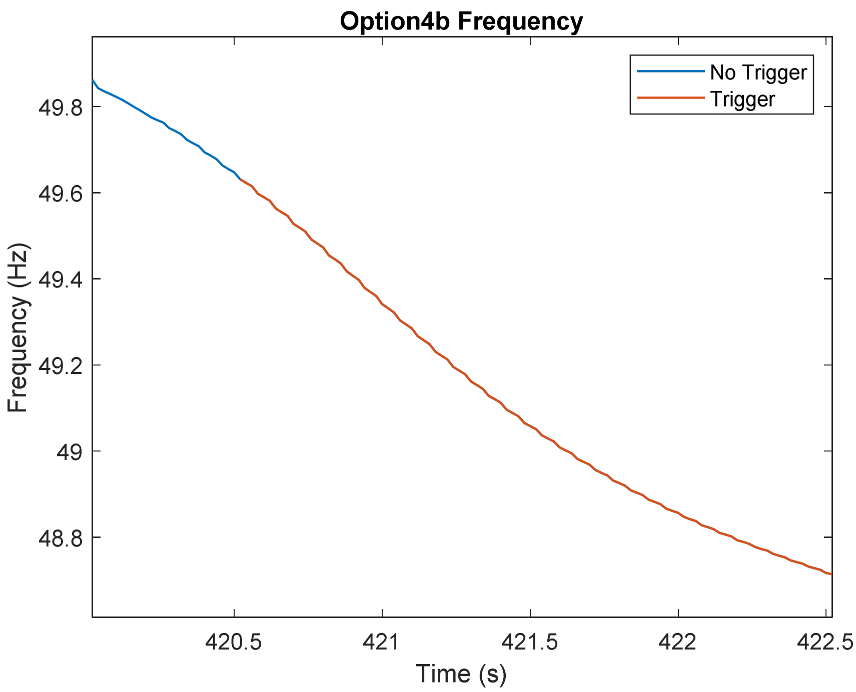

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
330
330.5
331
331.5
332
Time (s)

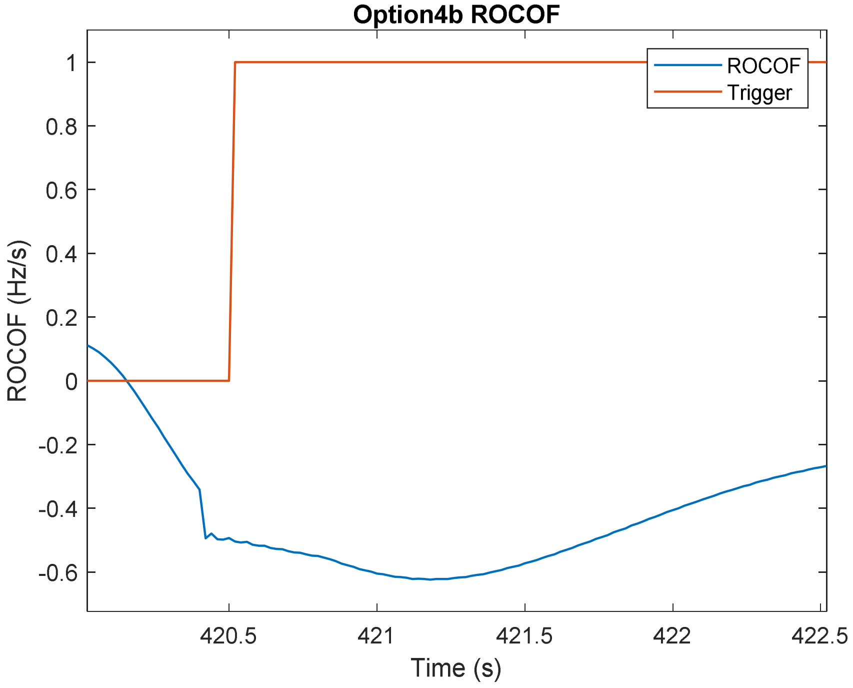

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
330
330.5
331
331.5
332
Time (s)

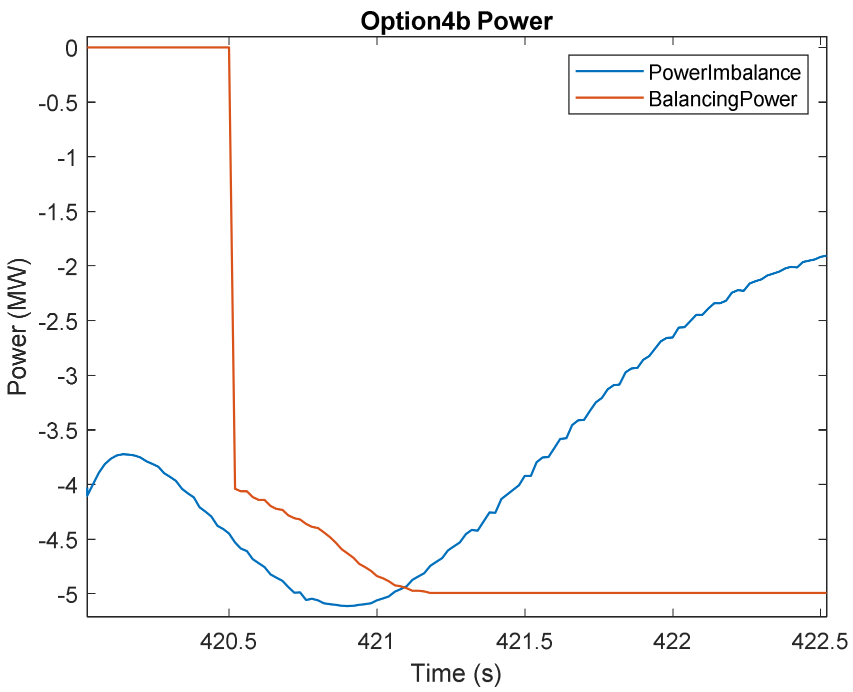

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
400
400.5
401
401.5
402
Time (s)

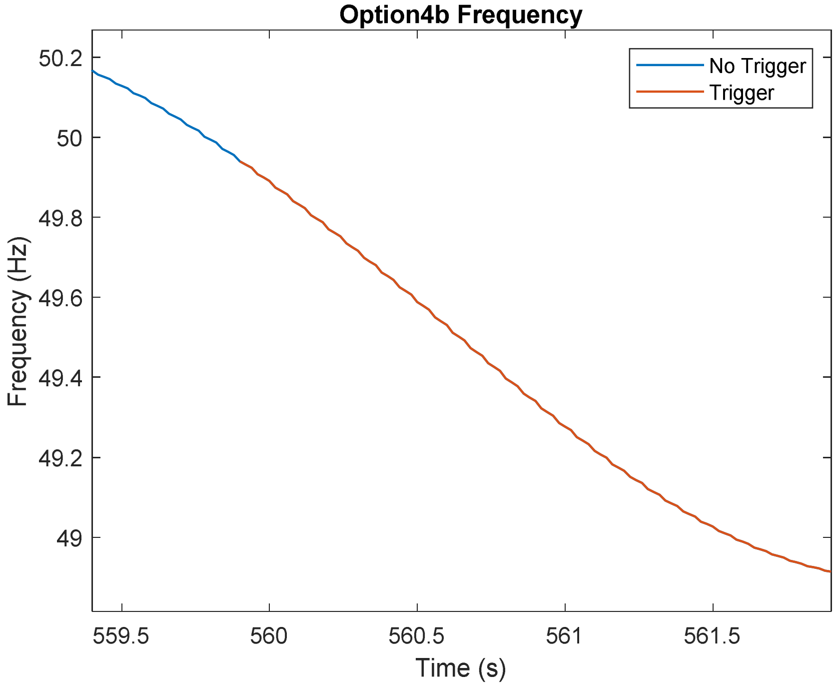

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
400
400.5
401
401.5
402
Time (s)

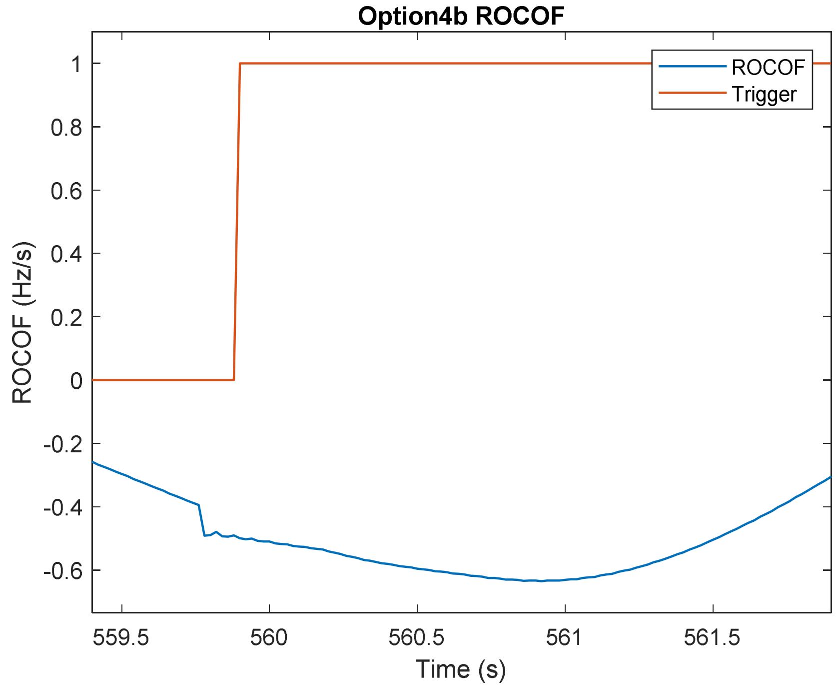

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
400
400.5
401
401.5
402
Time (s)

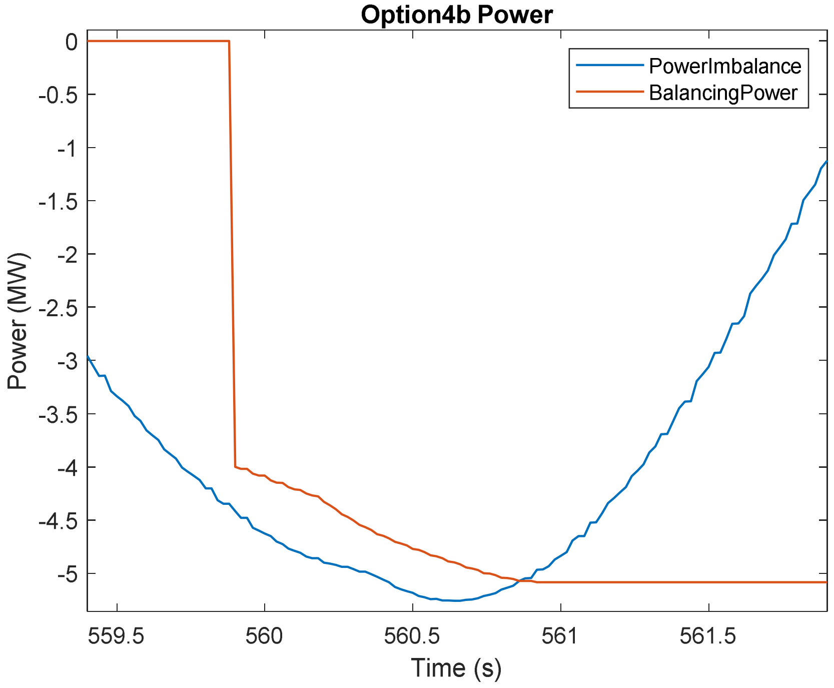

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
49.8
49.6
49.4
49.2
49
48.8
420.5
421
421.5
422
422.5
Time (s)


Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
420.5
421
421.5
422
422.5
Time (s)

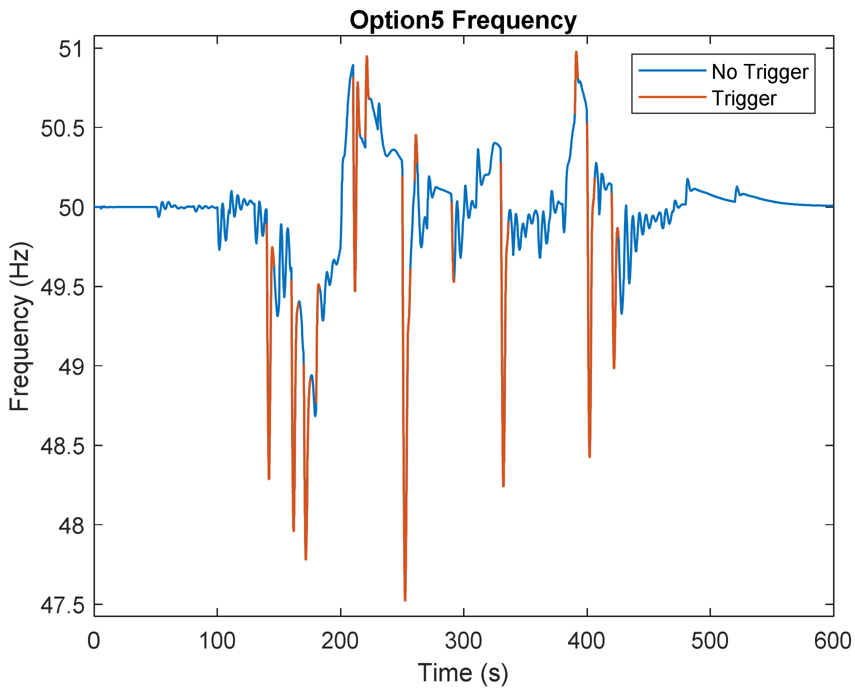

Option4b Power
PowerImbalance
BalancingPower
Power (MW)
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
-5
420.5
421
421.5
422
422.5
Time (s)

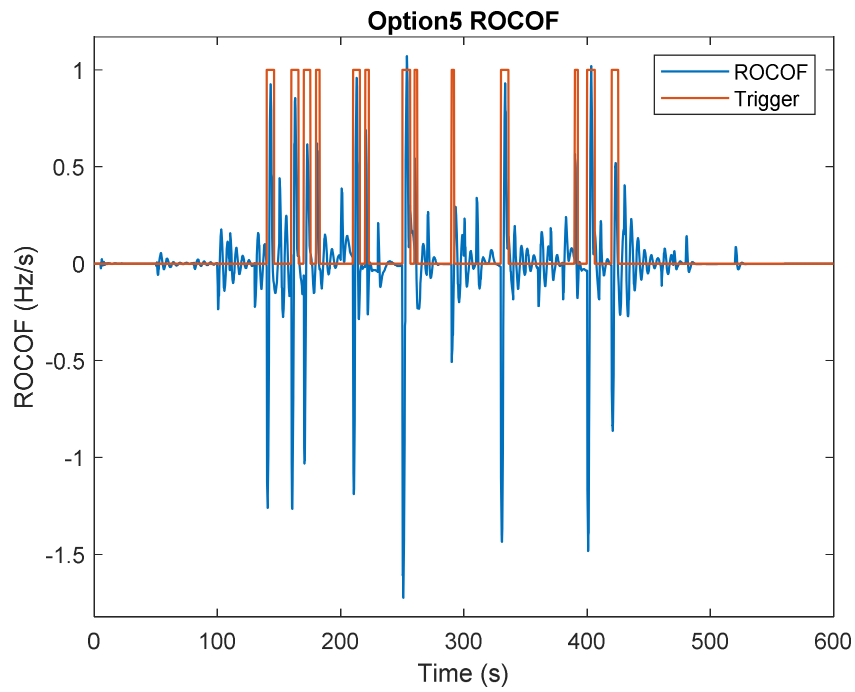

Option4b Frequency
No Trigger
Trigger
Frequency (Hz)
50.2
50
49.8
49.6
49.4
49.2
49
559.5
560
560.5
561
561.5
Time (s)

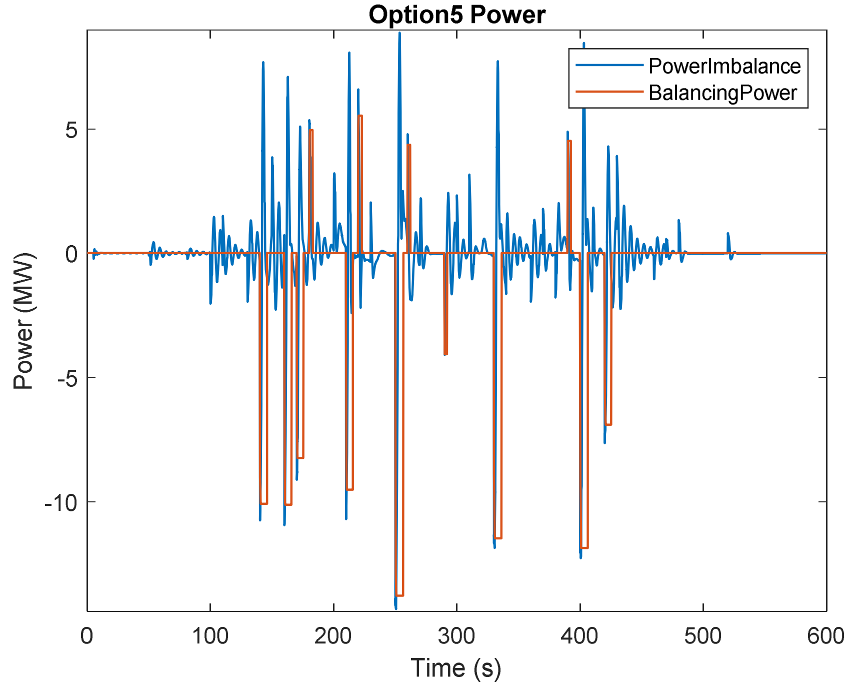

Option4b ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
559.5
560
560.5
561
561.5
Time (s)

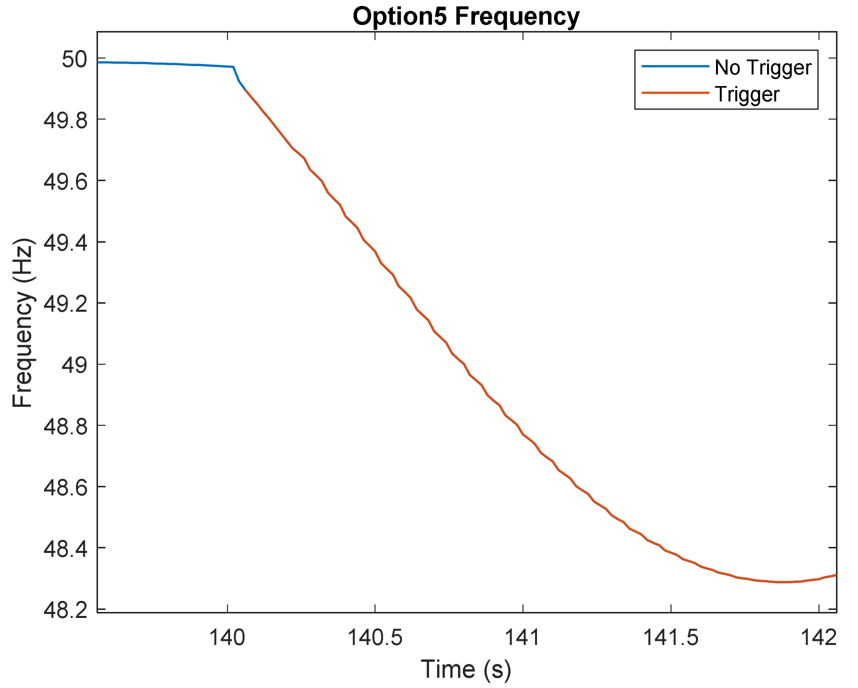

Option4b Power
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
-4.5
-5
Power (MW)
559.5
560
560.5
561
561.5
Time (s)
PowerImbalance
BalancingPower

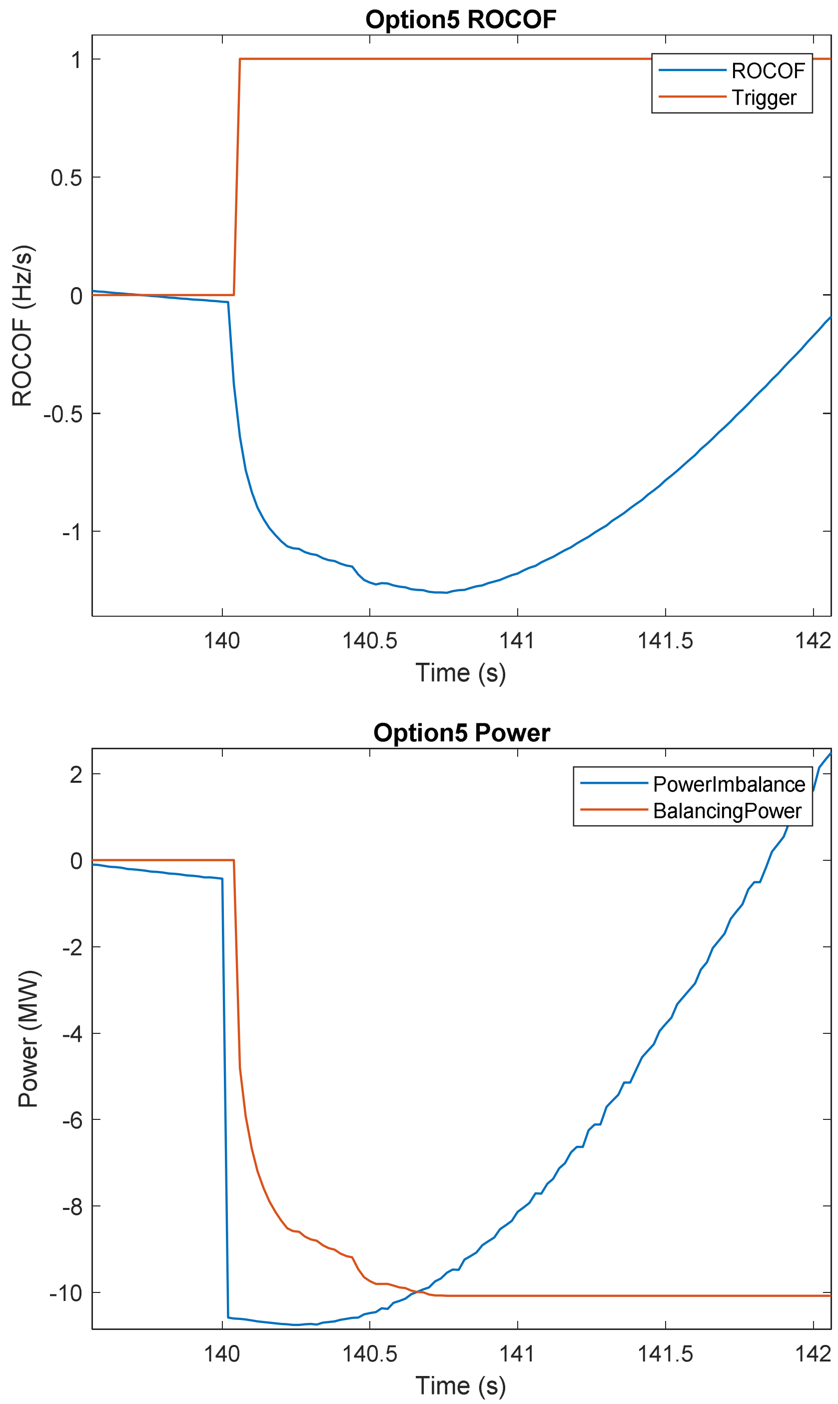
B.1.6 Restoration Option 5

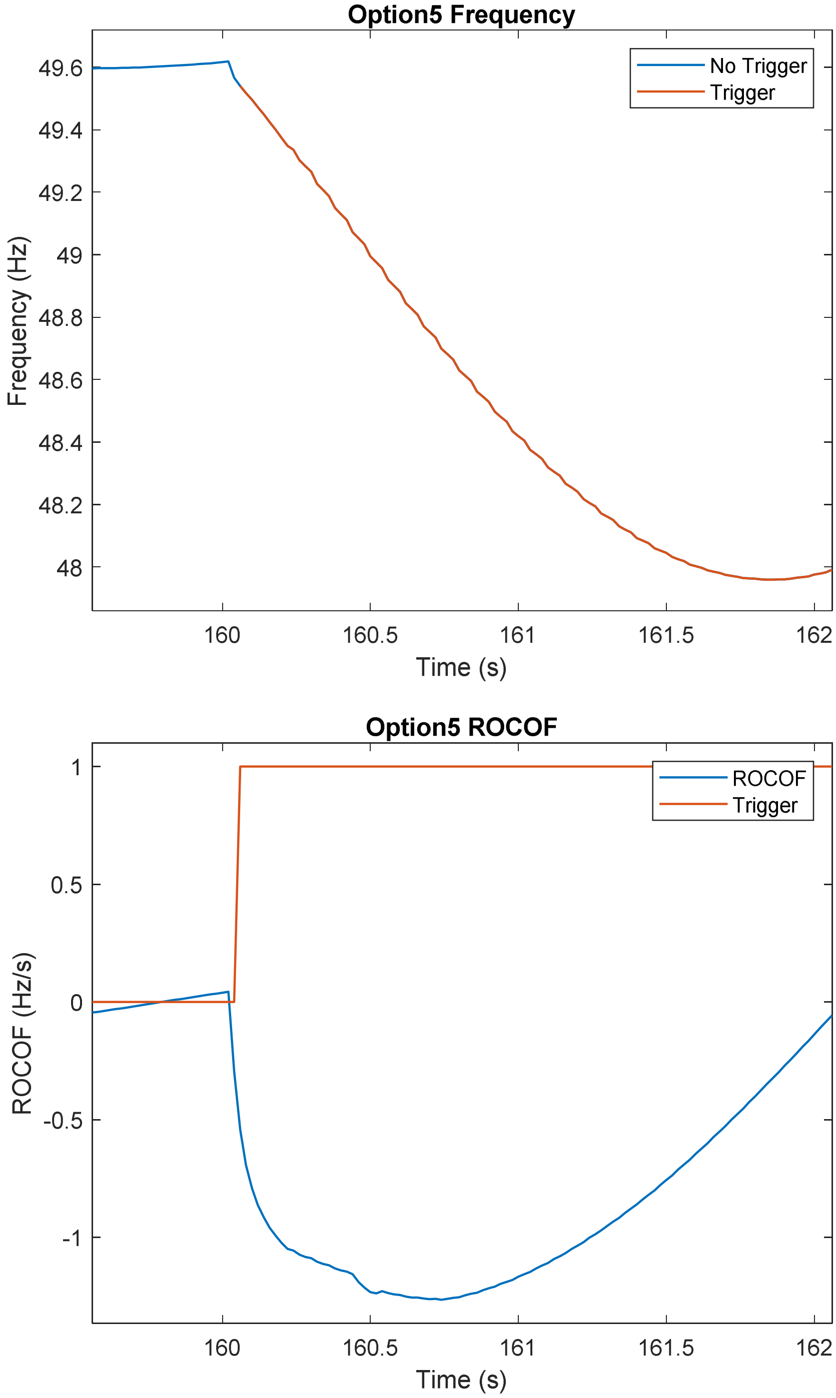


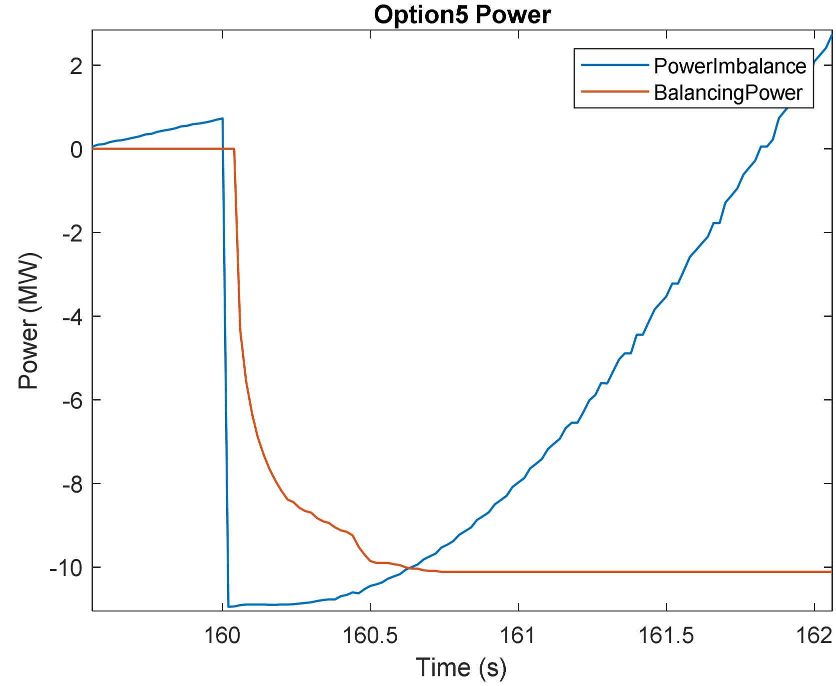


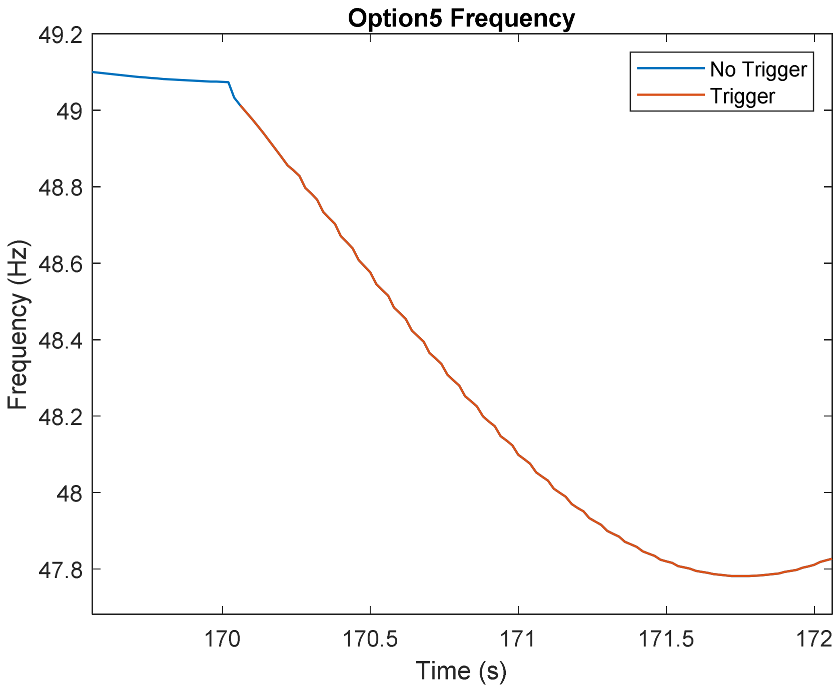

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
5
0
-5
-10
0
100
200
300
400
500
600
Time (s)

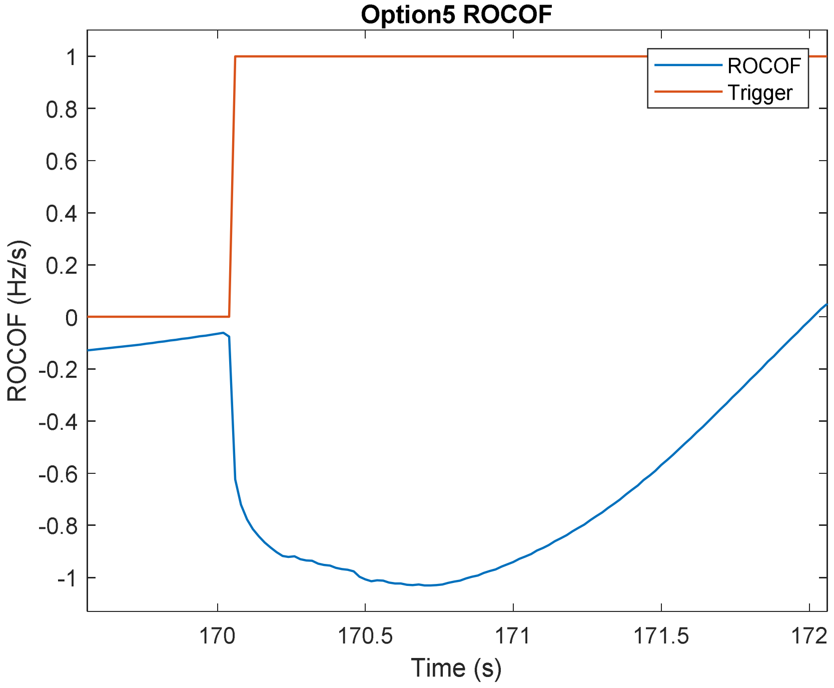

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.8
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
140
140.5
141
141.5
142
Time (s)

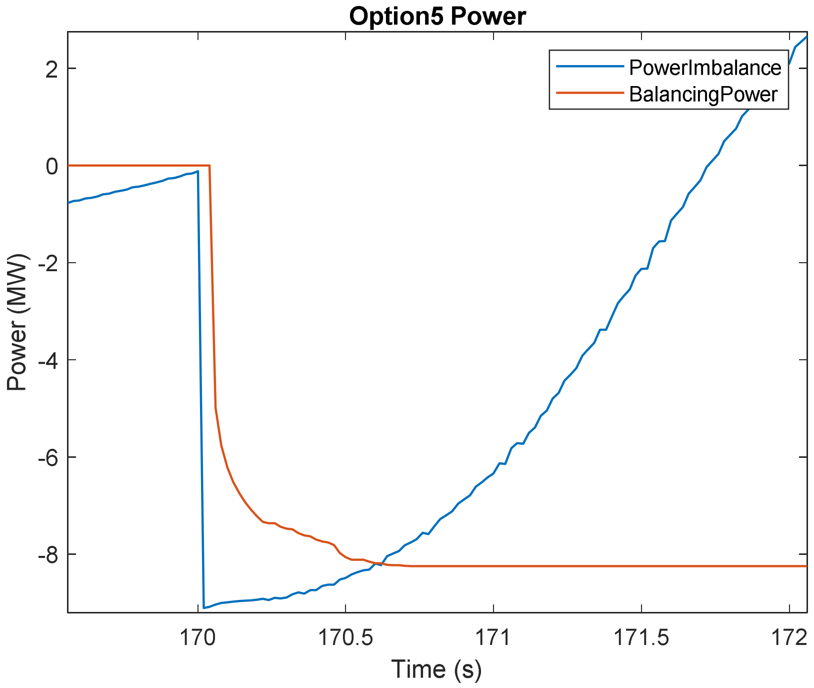

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
140
140.5
141
141.5
142
Time (s)
Option5 Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
-10
140
140.5
141
141.5
142
Time (s)

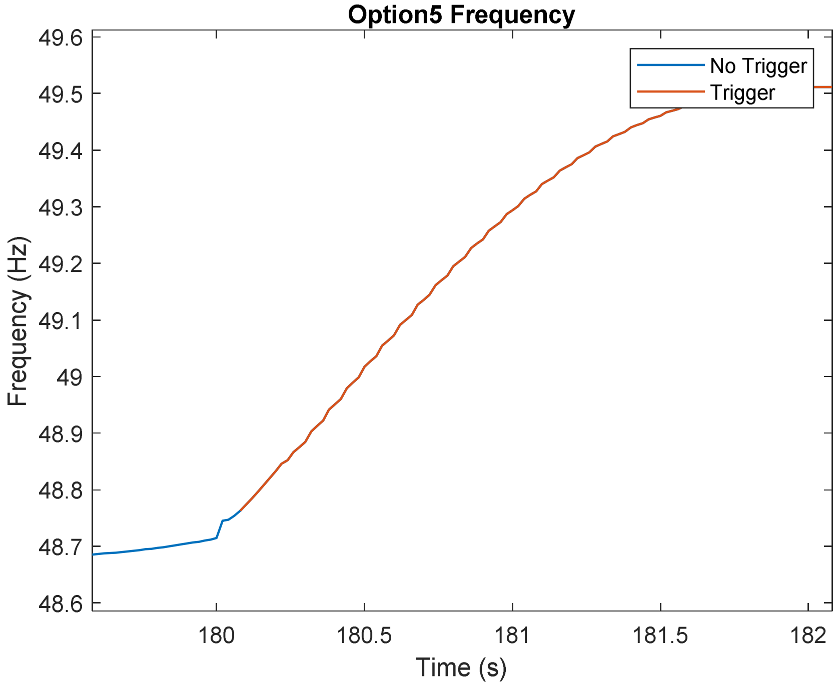

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
49.6
49.4
49.2
49
48.8
48.6
48.4
48.2
48
160
160.5
161
161.5
162
Time (s)
Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
160
160.5
161
161.5
162
Time (s)

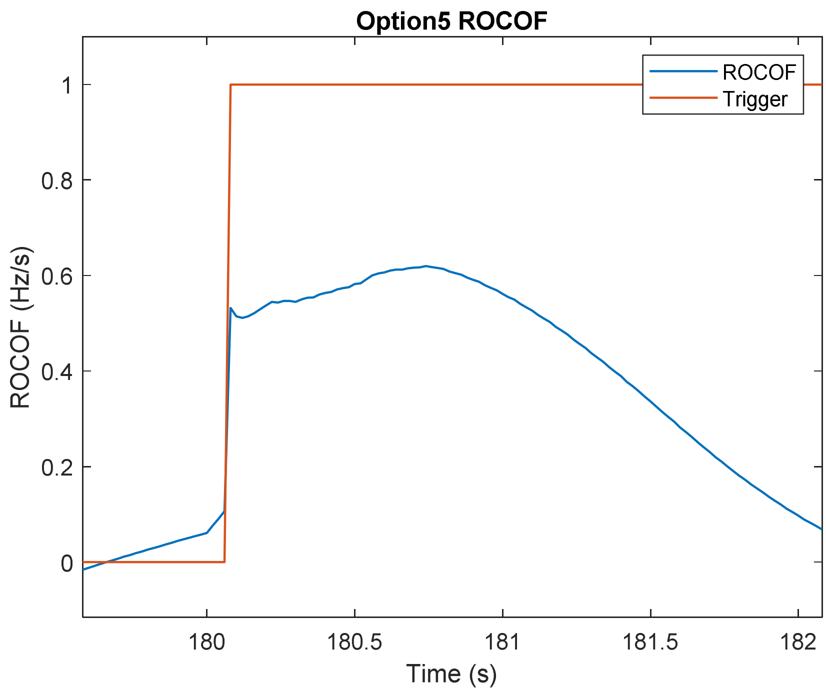

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
-10
160
160.5
161
161.5
162
Time (s)

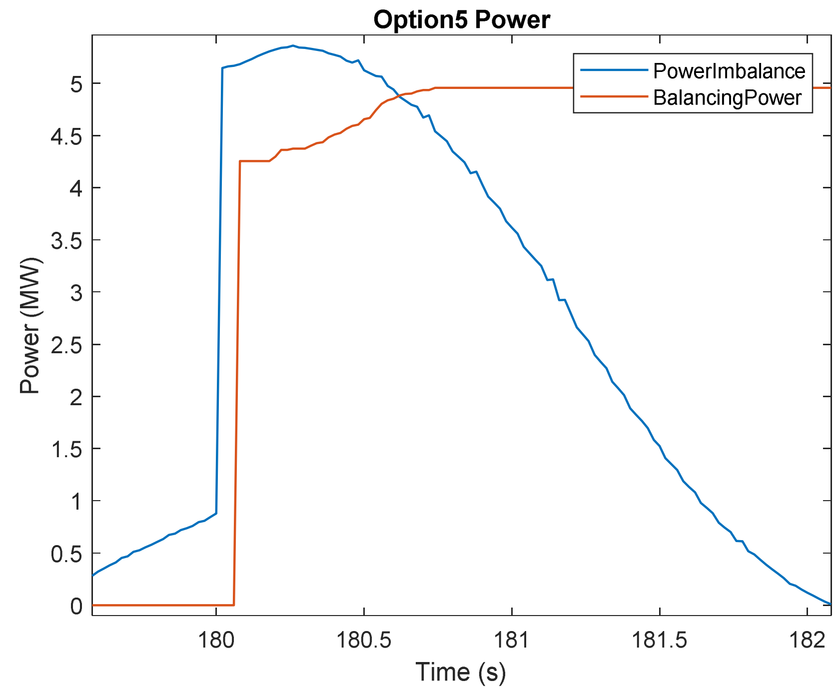

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
49.2
49
48.8
48.6
48.4
48.2
48
47.8
170
170.5
171
171.5
172
Time (s)

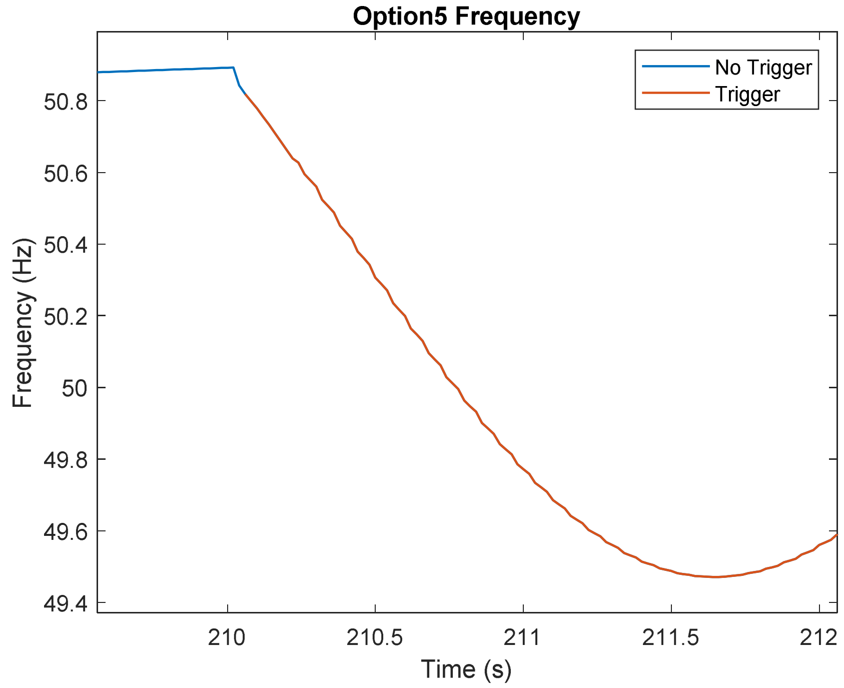

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
-1
170
170.5
171
171.5
172
Time (s)

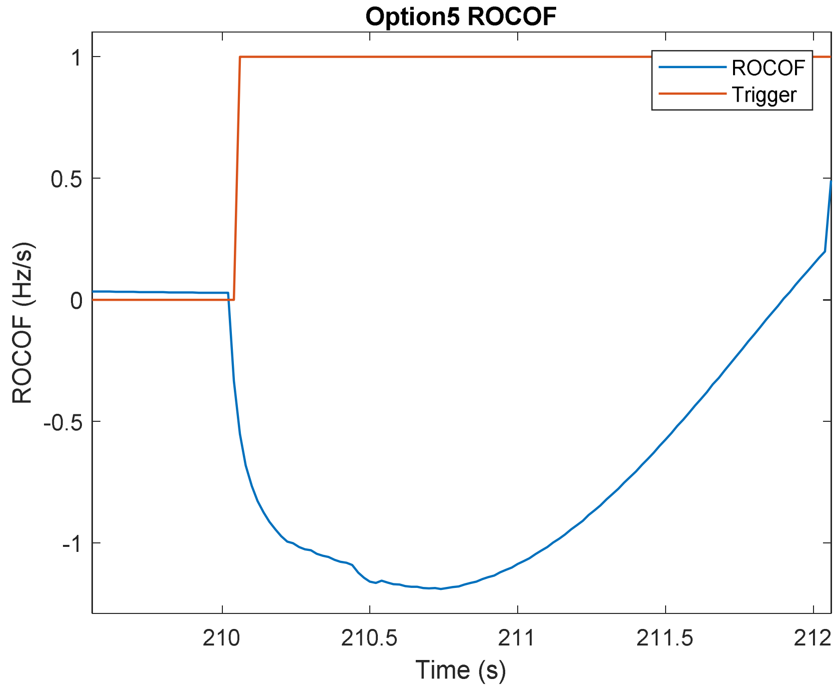

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
2
0
-2
-4
-6
-8
170
170.5
171
171.5
172
Time (s)

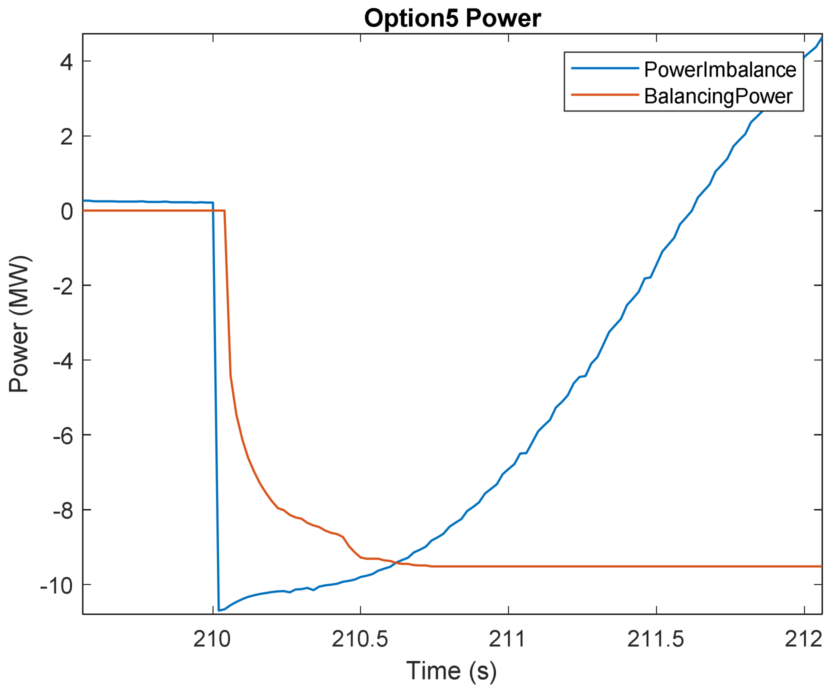

Option5 Frequency
Frequency (Hz)
49.6
49.5
49.4
49.3
49.2
49.1
49
48.9
48.8
48.7
48.6
180
180.5
181
181.5
182
Time (s)
No Trigger
Trigger

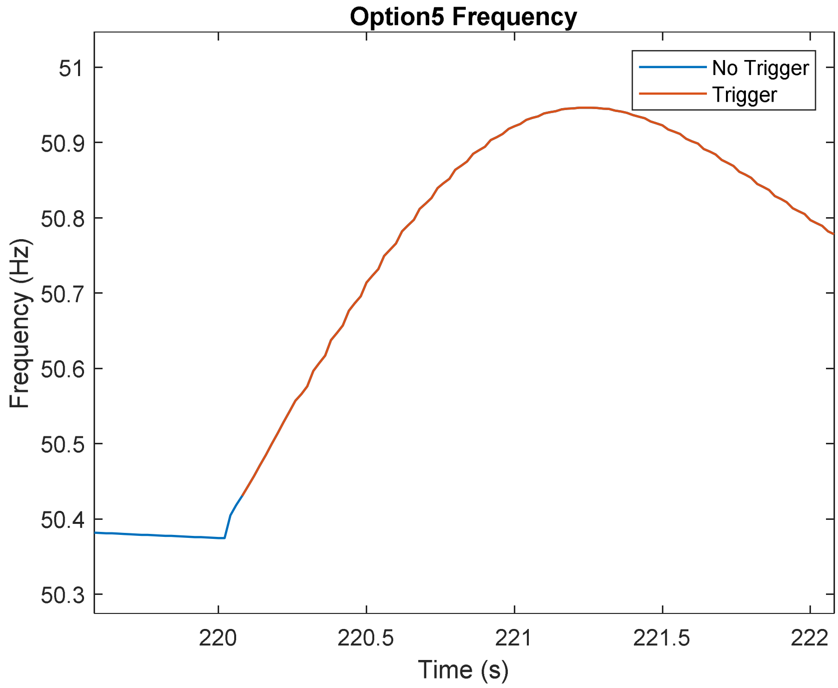

Option5 ROCOF
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
180
180.5
181
181.5
182
Time (s)
ROCOF
Trigger

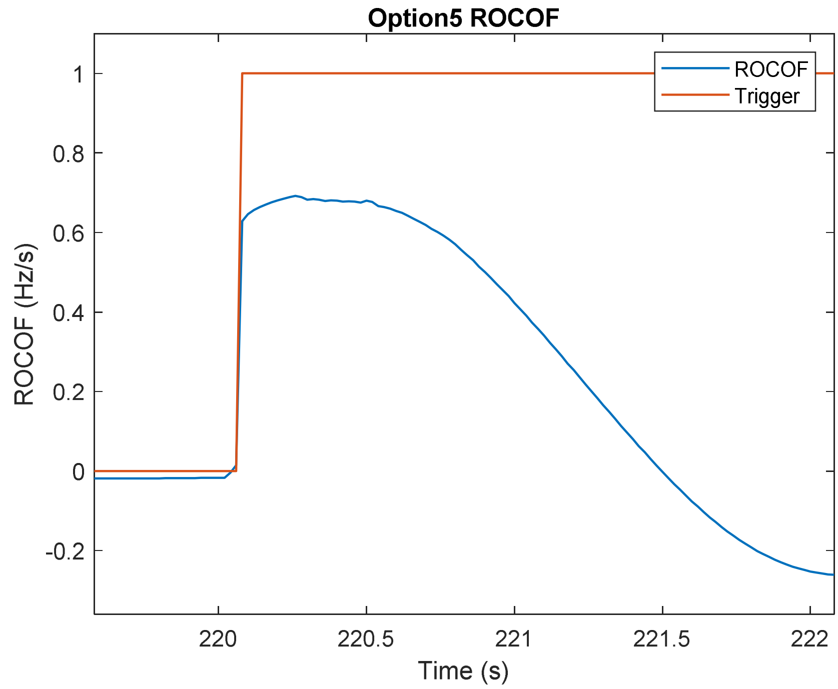

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
0
0.5
1
1.5
2
2.5
3
3.5
4
4.5
5
180
180.5
181
181.5
182
Time (s)

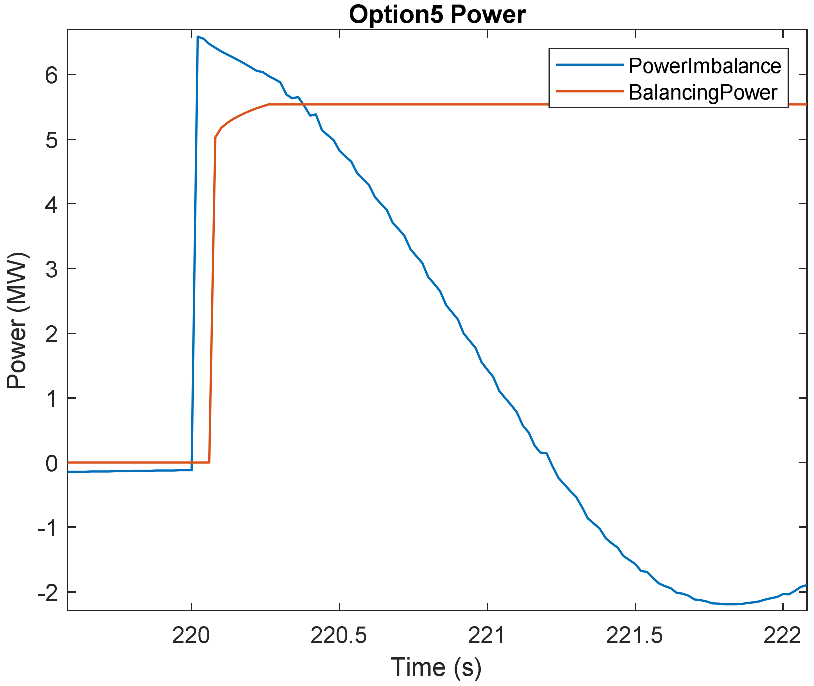

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
49.4
49.6
49.8
50
50.2
50.4
50.6
50.8
210
210.5
211
211.5
212
Time (s)

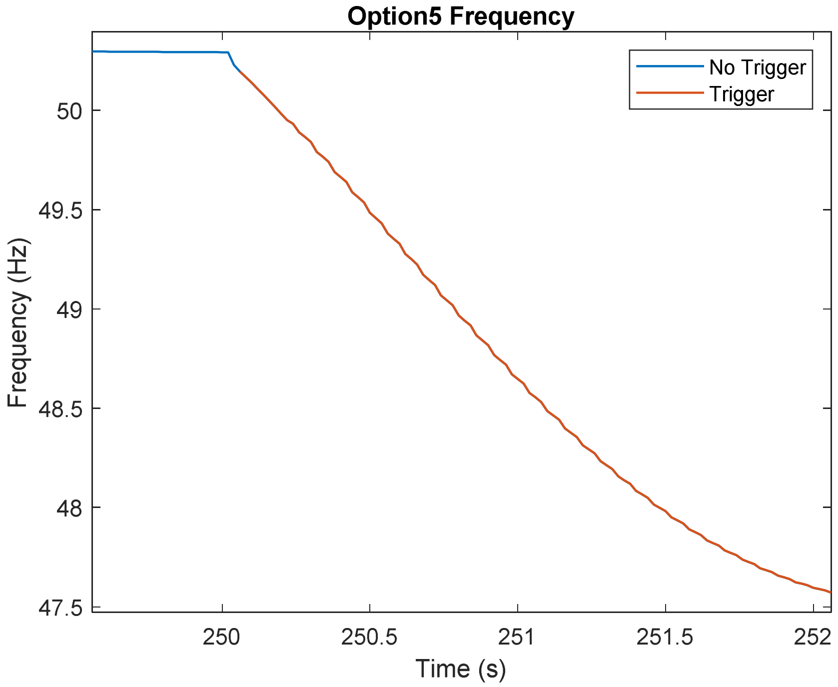

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
210
210.5
211
211.5
212
Time (s)

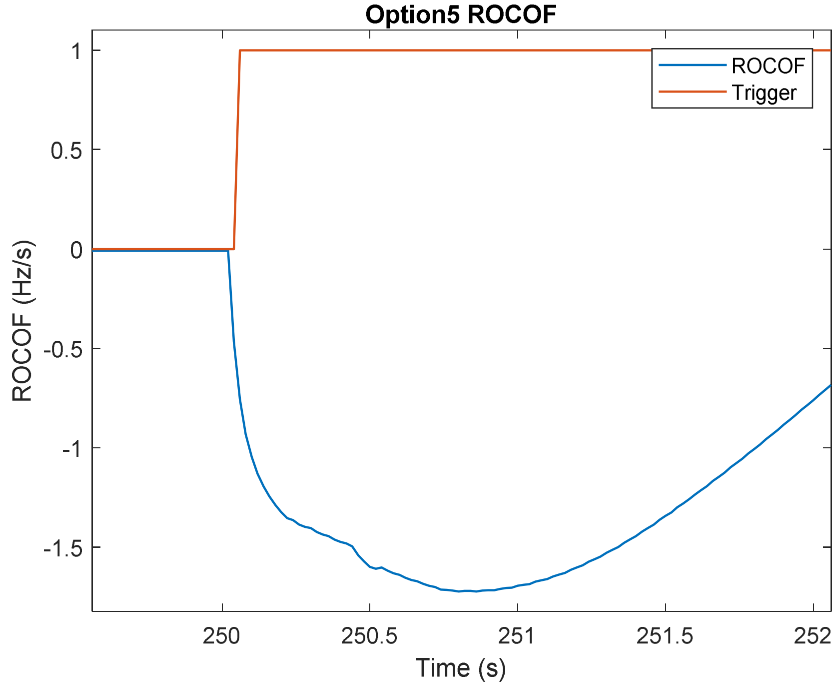

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
4
2
0
-2
-4
-6
-8
-10
210
210.5
211
211.5
212
Time (s)

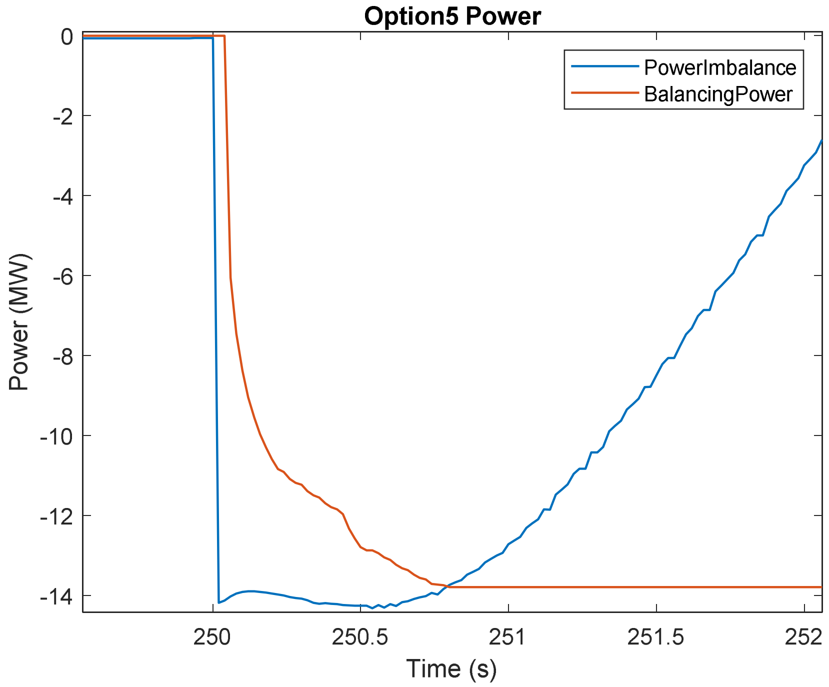

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.9
50.8
50.7
50.6
50.5
50.4
50.3
220
220.5
221
221.5
222
Time (s)

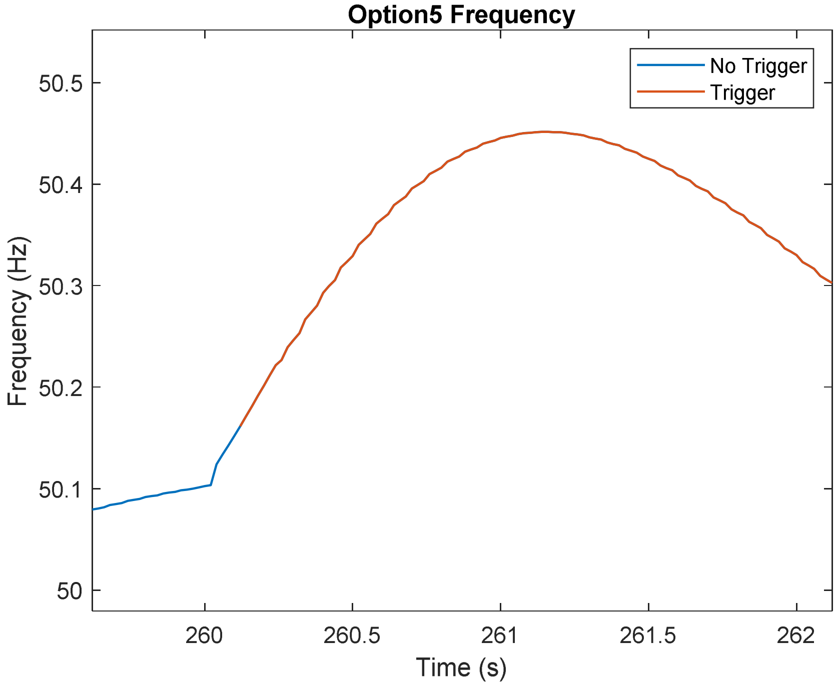

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
220
220.5
221
221.5
222
Time (s)

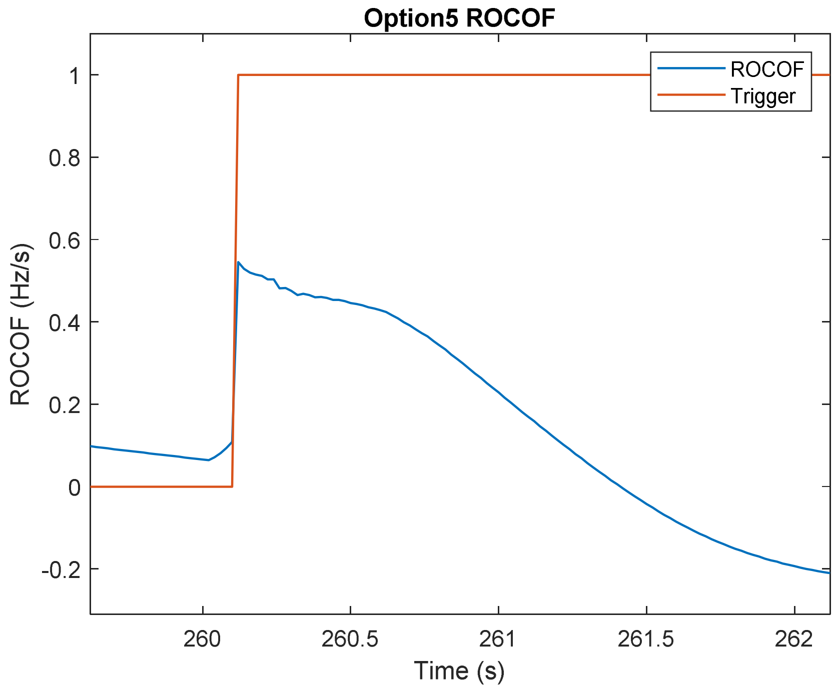

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
6
5
4
3
2
1
0
-1
-2
220
220.5
221
221.5
222
Time (s)

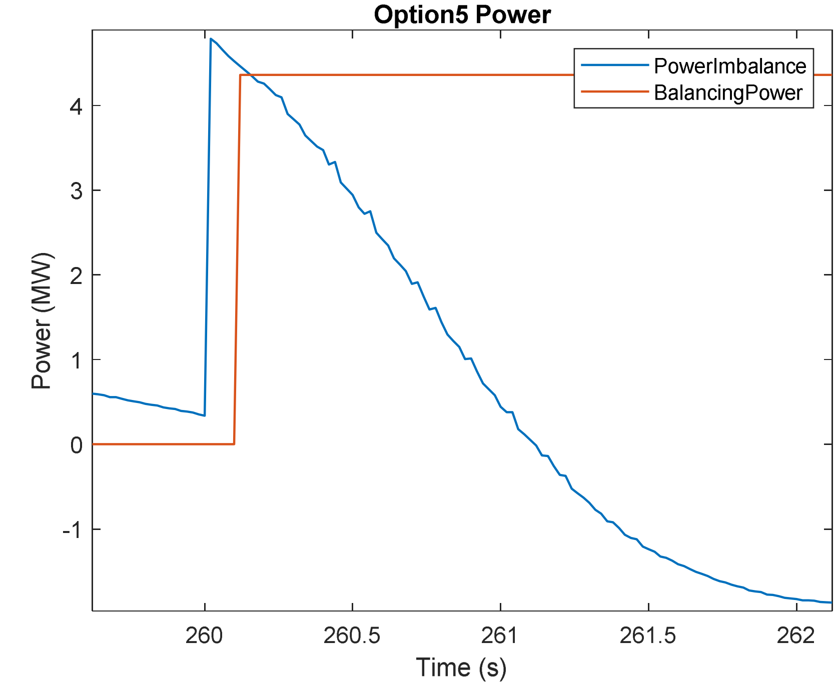

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
48
47.5
250
250.5
251
251.5
252
Time (s)

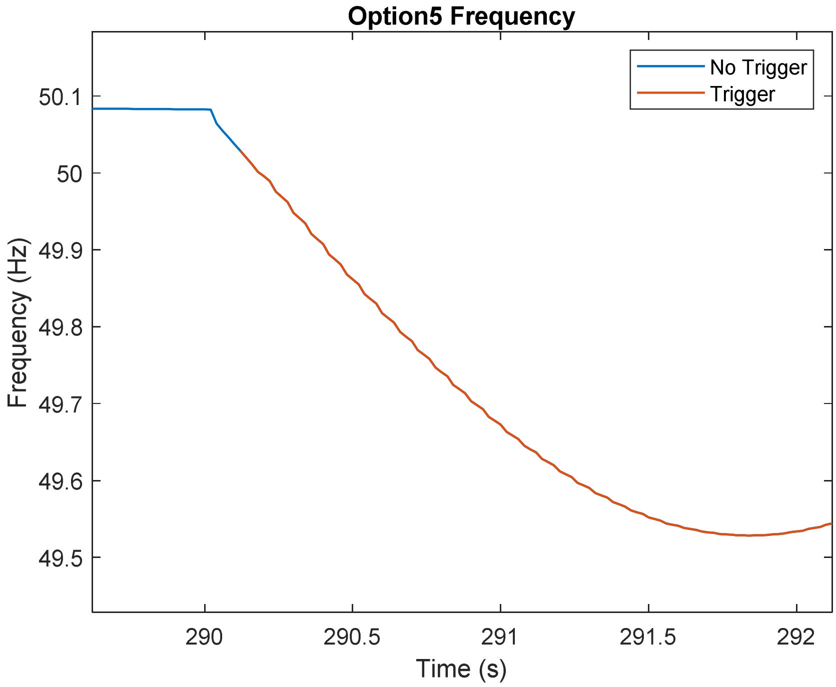

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
250
250.5
251
251.5
252
Time (s)

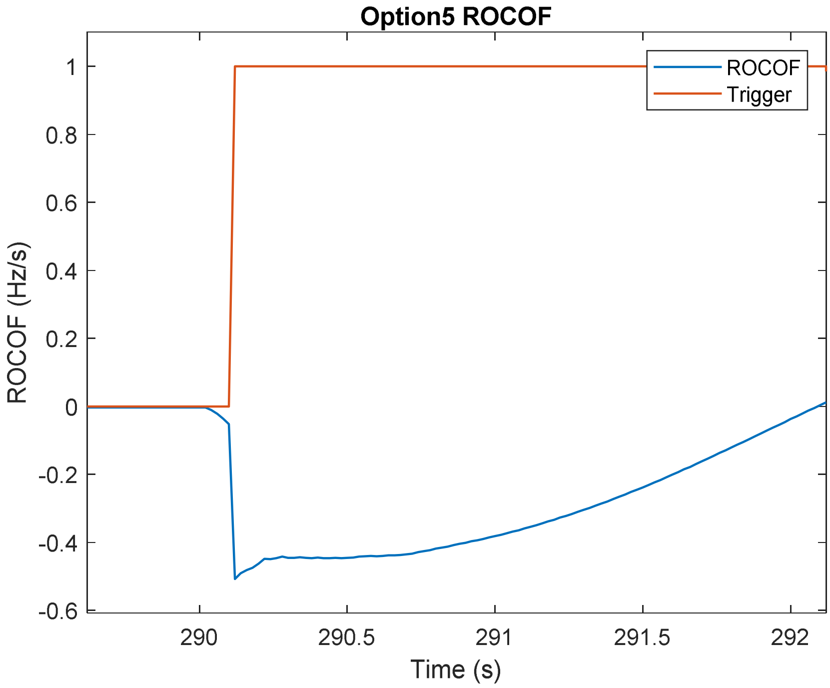

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
-14
250
250.5
251
251.5
252
Time (s)

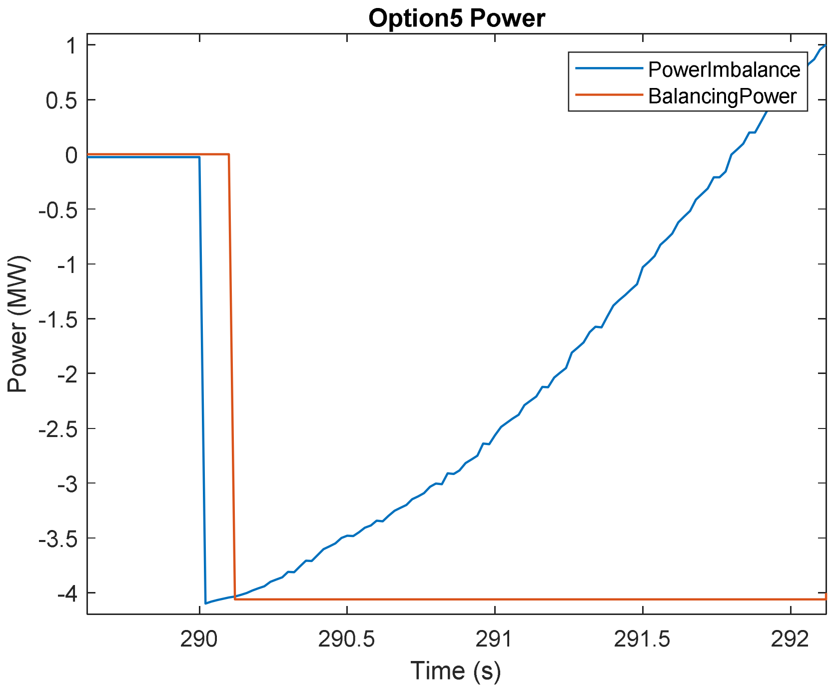

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50.5
50.4
50.3
50.2
50.1
50
260
260.5
261
261.5
262
Time (s)

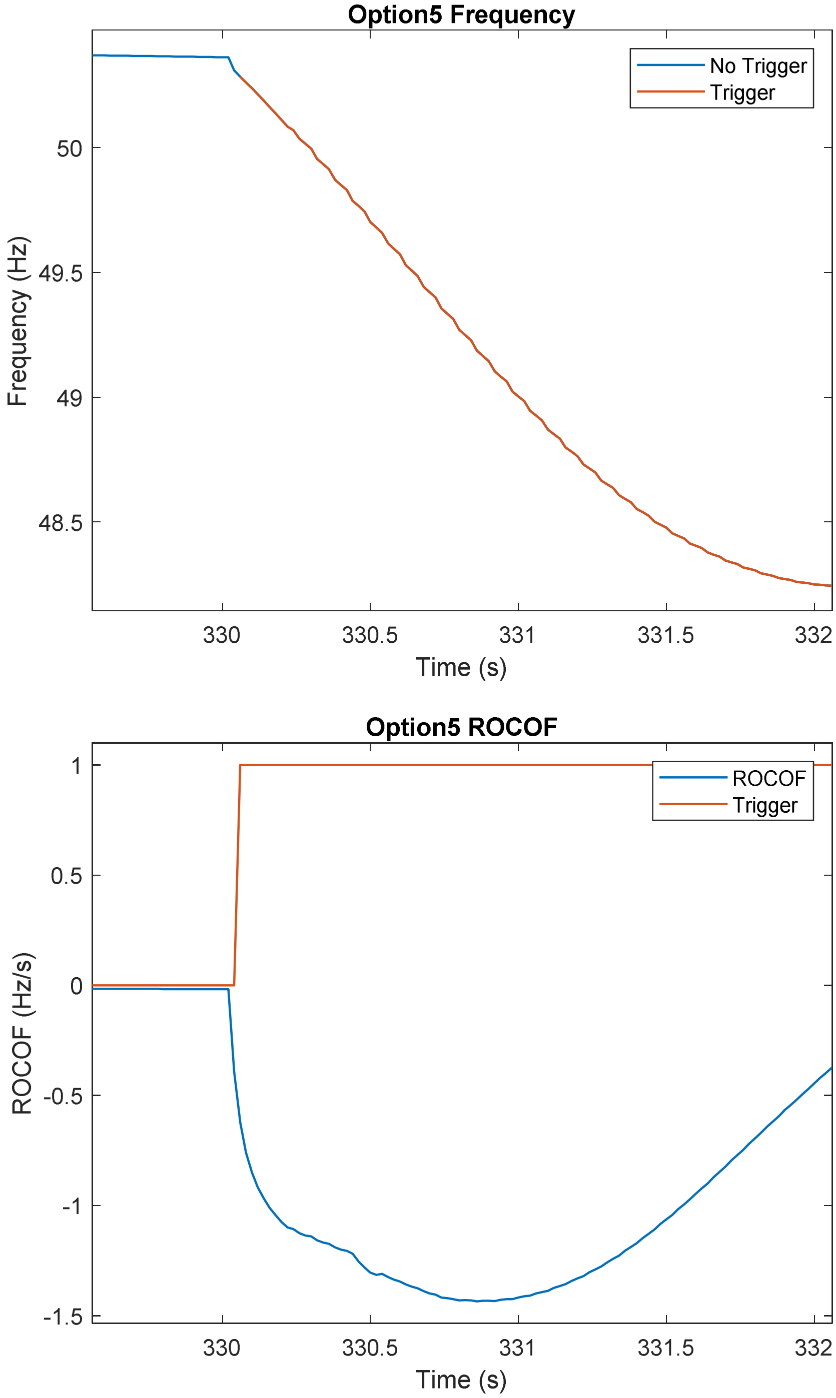

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
260
260.5
261
261.5
262
Time (s)

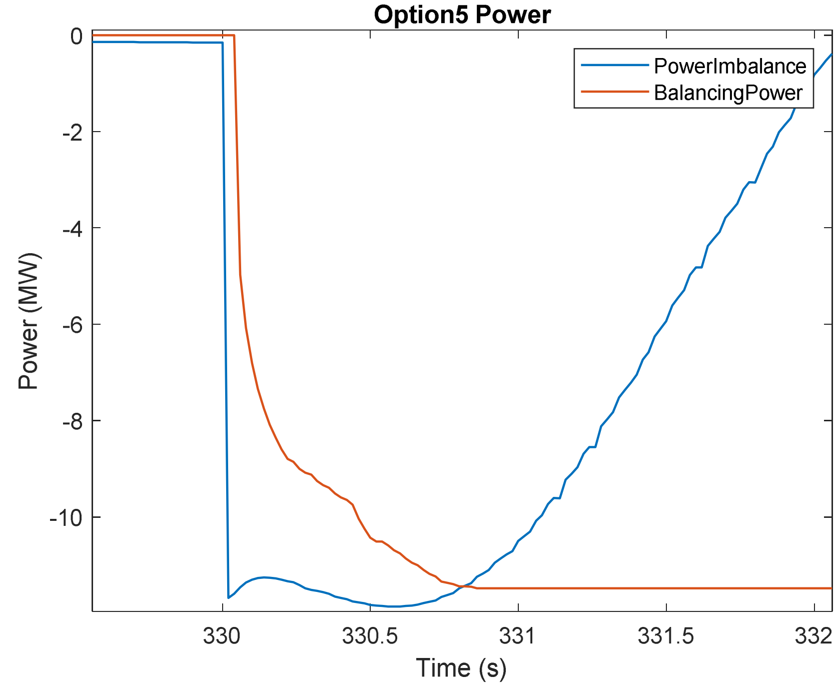

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
260
260.5
261
261.5
262
Time (s)

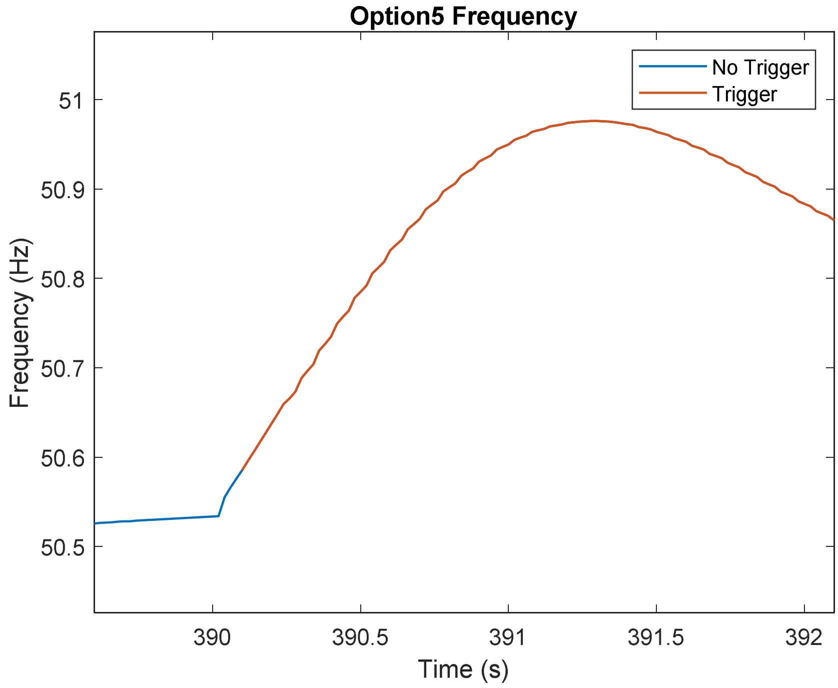

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50.1
50
49.9
49.8
49.7
49.6
49.5
290
290.5
291
291.5
292
Time (s)

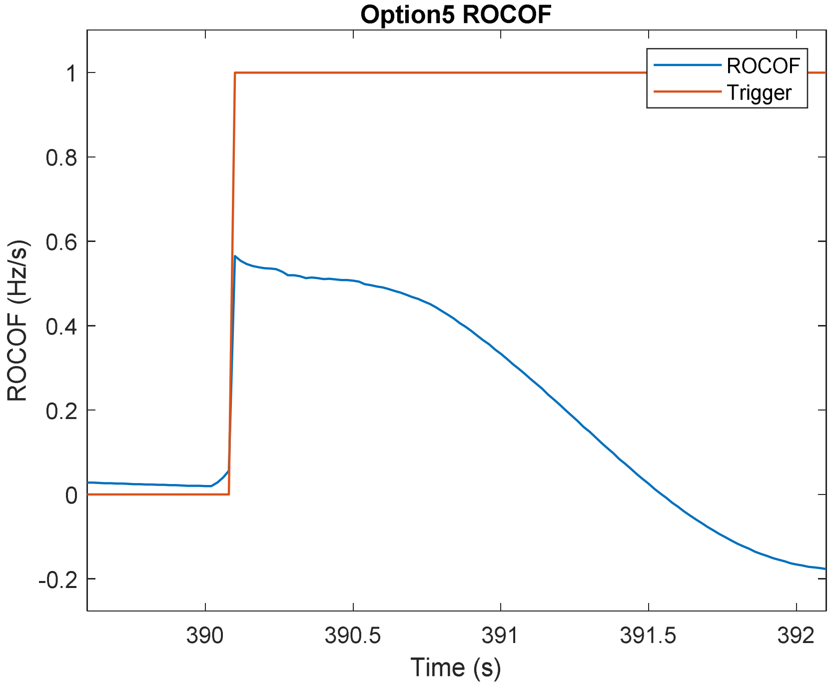

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
290
290.5
291
291.5
292
Time (s)

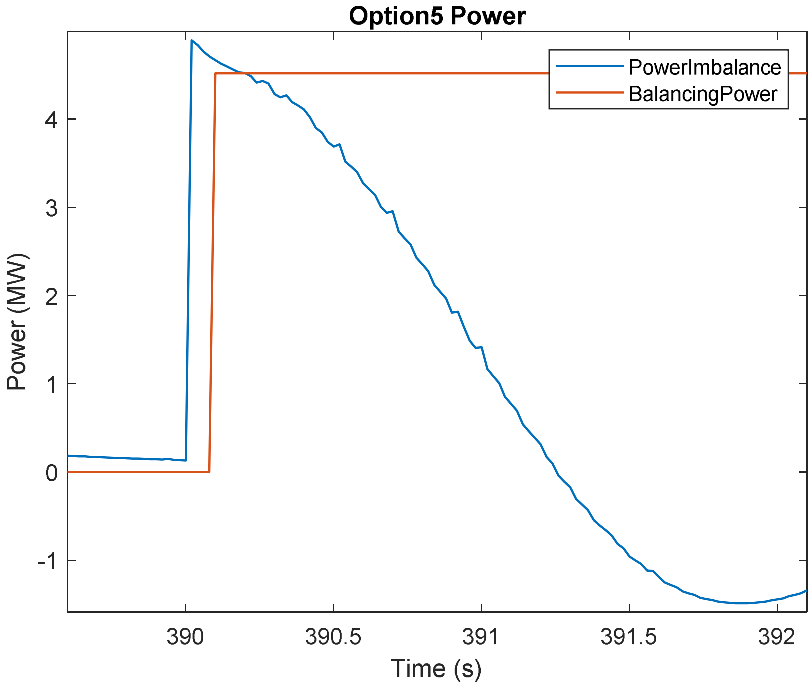

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
1
0.5
0
-0.5
-1
-1.5
-2
-2.5
-3
-3.5
-4
290
290.5
291
291.5
292
Time (s)

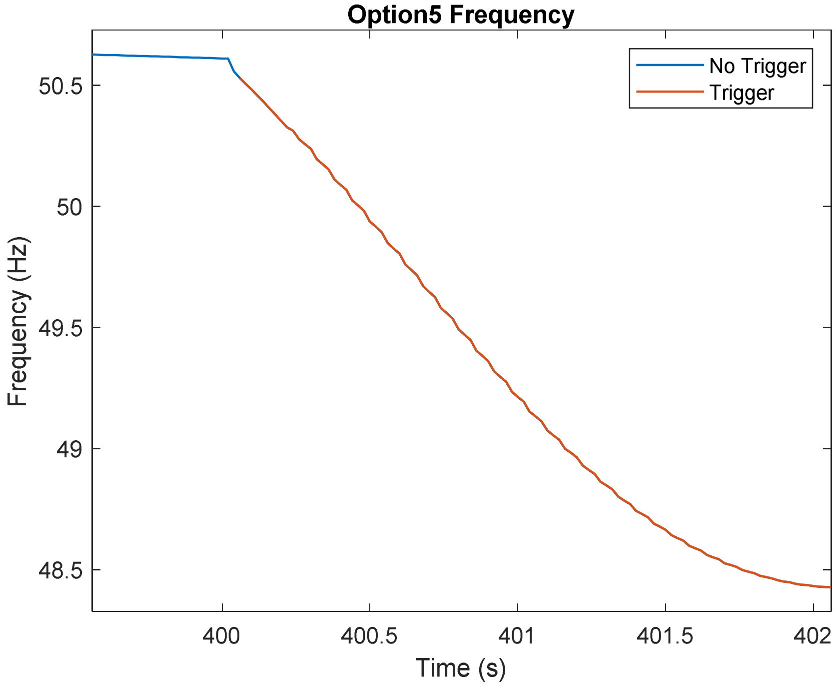

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50
49.5
49
48.5
330
330.5
331
331.5
332
Time (s)
Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.5
0
-0.5
-1
-1.5
330
330.5
331
331.5
332
Time (s)

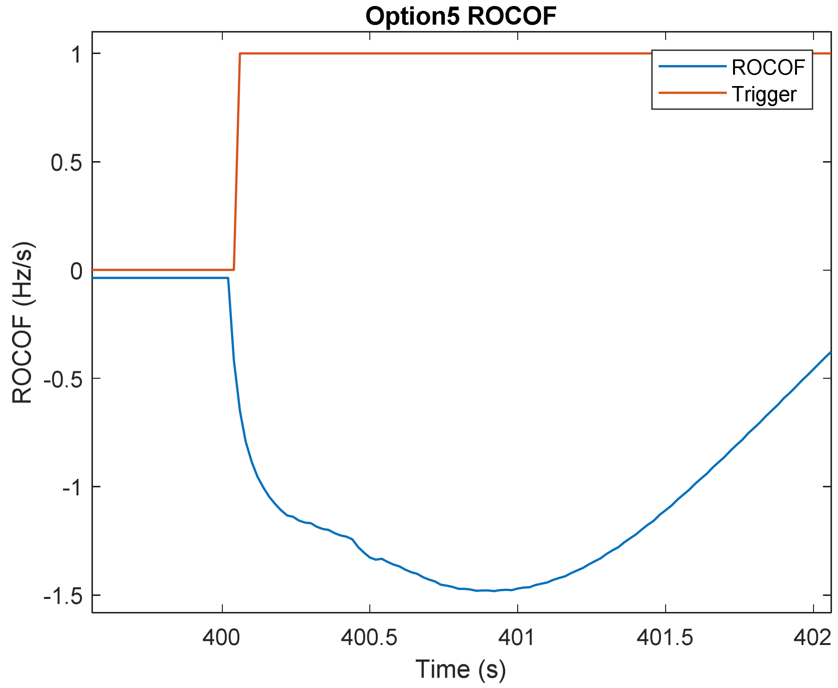

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
330
330.5
331
331.5
332
Time (s)

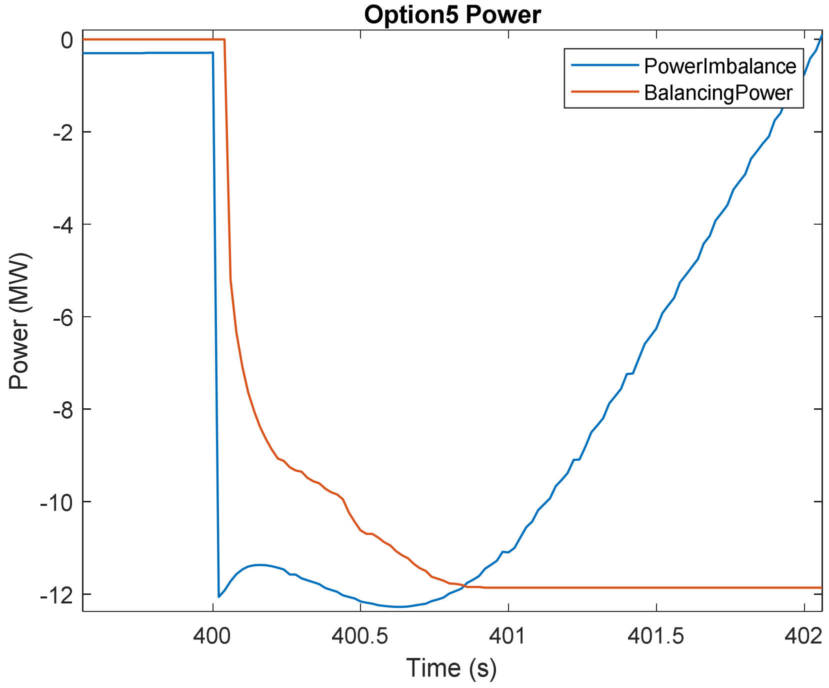

Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
51
50.9
50.8
50.7
50.6
50.5
390
390.5
391
391.5
392
Time (s)

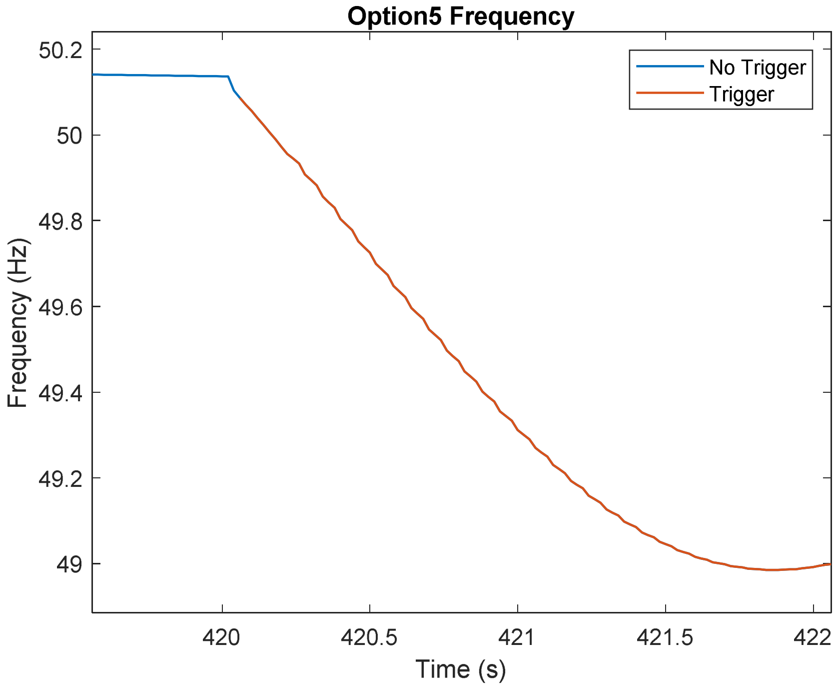

Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
390
390.5
391
391.5
392
Time (s)

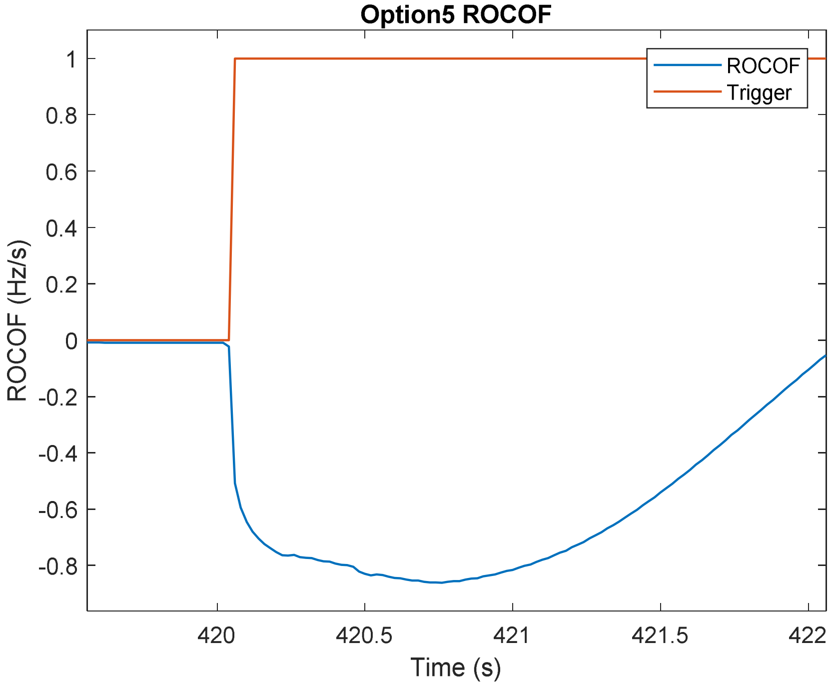

Option5 Power
PowerImbalance
BalancingPower
Power (MW)
4
3
2
1
0
-1
390
390.5
391
391.5
392
Time (s)

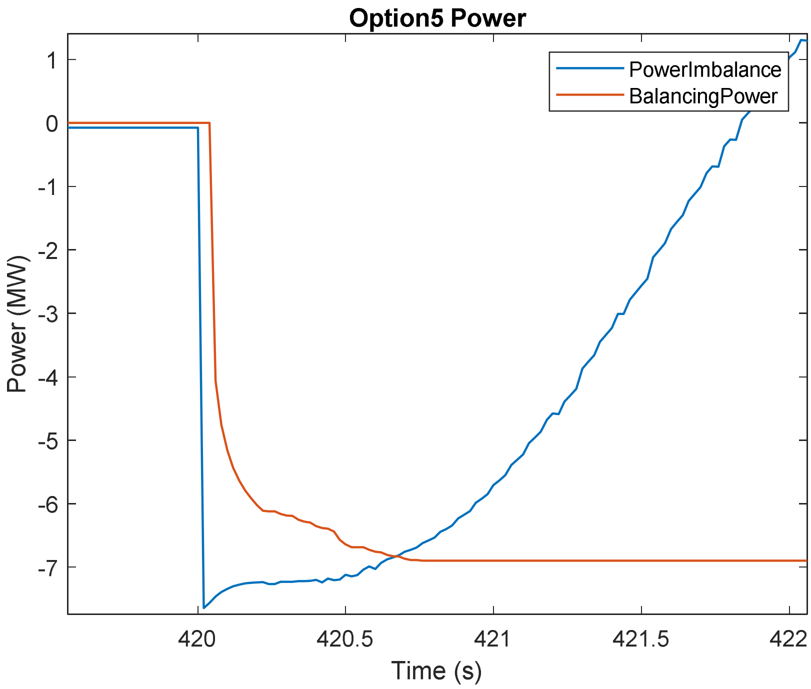

Option5 Frequency
No Trigger
Trigger
50.5
50
49.5
49
48.5
Frequency (Hz)
400
400.5
401
401.5
402
Time (s)


Option5 ROCOF
ROCOF
Trigger
1
0.5
0
-0.5
-1
-1.5
ROCOF (Hz/s)
400
400.5
401
401.5
402
Time (s)


Option5 Power
PowerImbalance
BalancingPower
Power (MW)
0
-2
-4
-6
-8
-10
-12
400
400.5
401
401.5
402
Time (s)


Option5 Frequency
No Trigger
Trigger
Frequency (Hz)
50.2
50
49.8
49.6
49.4
49.2
49
420
420.5
421
421.5
422
Time (s)


Option5 ROCOF
ROCOF
Trigger
ROCOF (Hz/s)
1
0.8
0.6
0.4
0.2
0
-0.2
-0.4
-0.6
-0.8
420
420.5
421
421.5
422
Time (s)


Option5 Power
PowerImbalance
BalancingPower
Power (MW)
1
0
-1
-2
-3
-4
-5
-6
-7
420
420.5
421
421.5
422
Time (s)

Appendix C: Equipment specifications

C.1 Server specification for WAMS (PhasorPoint) service

- Model: Dell R430 – **or** – HP DL360 Gen10 – **or** equivalent
- CPU: 1 x Intel Xeon Silver 4216 (22MB cache) **or** 1 x Intel Xeon Gold 5220 (24.75MB cache) **or** 1x Intel Xeon Gold 5120 (19.25MB cache) **or** 1 x Intel Xeon E5-2650 v4 **
- RAM: **min 32GB**
- HDD: RAID I Disk array, min 250GB for server OS and PhasorPoint installation. **Recommended**: SAS 6.0Gbps 15k rpm disks
- SSD RAID 1 recommended for PostgreSQL database (Write-Intensive or Mixed-Mode SSDs only)
- HDD: RAID V Disk array, min 2TB usable storage (or SAN) depending on how long data is to be stored for. **Recommended:** SAS 10k rpm disks. A larger number of moderately sized disks is preferable to a smaller number of very large disks.
- Hot Swap disk, fans and redundant power supply

C.2 Server specification for Public Key Infrastructure

- Model: Dell R430 – **or** – HP DL360 Gen10 – **or** equivalent
- CPU: 1 x Intel Xeon Silver 4216 (22MB cache) **or** 1 x Intel Xeon Gold 5220 (24.75MB cache) **or** 1x Intel Xeon Gold 5120 (19.25MB cache) **or** 1 x Intel Xeon E5-2650 v4 **
- RAM: **min 16GB**
- HDD **or** SSD: **RAID I** Disk array, min 250GB for server OS and PKI installation. **Recommended**: SAS 6.0Gbps 15k rpm disks
- Hot Swap disk, fans and redundant power supply

** Please note that the number of cores and cache size must be considered if choosing a different CPU, not just the clock speed **

C.3 Control centre switches

- Cisco Catalyst 2960-X Series Switch
- GE Reason H49 PRP RedBox switch
- Cat 6 ethernet cables

C.4 Control centre and Substation controllers

- GE PhasorController PhC21x with TPUS-2 power supply unit
- Cat 6 ethernet cables

C.5 Substation switches

- GE Reason S20 Switch
- GE Reason H49 PRP RedBox switch
- Cat 6 fiber optic cables

C.6 Substation PMUs

- GE DR60
- Cat 6 ethernet cables

Appendix D: List of standards

Standard	Description
IEC 1012	Software validation processes standard
IEC 12207	Software lifecycle standard
IEC 29119	Software testing standard
IEC 60812	FMEA standard
IEC 60870-5-104	SCADA protocol for electrical engineering and power system applications
IEC 61131-3	Standard for Programmable Logic Controllers
IEC 61508	Standard on Safety Related Systems
IEC 61511	Standard on Safety Instrumented Systems
IEC 61850	International protocol defining communications between IEDs in electrical substations
IEC 62443	Secure development standard
IEC 63351	Security standard for control protocol
IEC 63439-3	Parallel Redundancy (PRP)
IEEE 1588	Standard for Precision Time Protocol
IEEE 1613	Testing standard for communication devices in substations
IEEE C37.118-2011 (rev_2014)	IEEE standard Synchrophasor measurements for Power Systems
ISA TR84.00.09	Cybersecurity Standard
ISO 9001	Quality Management standard
ISO/IEC 20000-1	Information Technology services management standard
ISO/IEC 27000	Security Management Systems standard