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The Enhanced Frequency Control Capability (EFCC) project closing down report

nationalgridESO

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Chapter 1

Project background

Meeting UK carbon reduction targets requires a significant increase in the volume of renewables providing electricity. This reduces system inertia and gives rise to an increase in the volume and speed of frequency response to maintain system frequency. It will require the development of new, significantly faster and coordinated response solutions using renewables, demand side resources, and other new technologies. The Enhanced Frequency Control Capability (EFCC) project has been designed to find a resolution to this electricity system challenge.

The aim of the EFCC project was to develop and demonstrate an innovative new monitoring and control system (MCS) which obtains accurate frequency data at a regional level, calculates the required rate and volume of fast response and then enables the initiation of this required response within 0.5 seconds of a detected system frequency event.

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From an electricity system perspective, the project proposal would allow the network to operate with increasing volumes of non-synchronous generation and at lower levels of system inertia. The MCS has an additional benefit of allowing an increase in the maximum loss conditions which the system could be secured to, resulting in potential savings to electricity consumers.

In 2014, National Grid Electricity System Operator (NGESO), supported by commercial and academic partners, made a submission for the EFCC project under the Network Innovation Competition (NIC) mechanism. Ofgem approved the submission and issued the Project Direction on 19 December 2014 (Appendix F). The project was originally scheduled to run from January 2015 to March 2018, but was later extended to January 2019. This extension to the project duration allowed additional time to capture and analyse data from the commercial field trials and complete further performance testing on the MCS which will support any potential implementation of the control scheme onto the electricity network.

The total requested budget for the project was £8.5m to develop, test and demonstrate the first wide area control system (WACS) in Great Britain (GB) and confirm the technical capability of fast frequency response from a diverse range of potential service providers. Ultimately, this built confidence in the technology and provided a road map for any potential future implementation of a WACS on the National Electricity Transmission System (NETS).

The project was a collaboration between NGESO, GE Renewable Energy (formally known as Alstom Psymetrix), the University of Manchester, the University of Strathclyde, BELECTRIC, Flexitricity, Centrica/EPH, Ørsted (formally known as DONG Energy) and Siemens Gamesa Renewable Energy.

All the partners, including NGESO, were responsible for particular work package(s) which denoted their areas of expertise and knowledge, as shown in Table 1.

Partners	Work Package	Work Description
GE Renewable Energy	WP1: Development of the monitoring and control system (MCS)	Design and implementation of a wide area control system into physical hardware
Flexitricity Centrica/EPH BELECTRIC Ørsted and Siemens Gamesa Renewable	WP2: Assessment of different response providers	Assessment of how the MCS would interface with a range of technologies and confirmation of rapid frequency response capabilities
University of Manchester	WP3: Optimisation	Understand how the selected resources can be coordinated to provide optimised response
University of Strathclyde University of Manchester	WP4: Validation	Systematic testing of the MCS to confirm its performance capability and reliability
All	WP5: Knowledge dissemination	Share learning from the project with wider industry and stakeholders through a variety of communication channels
NGESO	WP6: Commercial	Create a new balancing service allowing immediate roll-out of the enhanced frequency control capability and achieving the savings envisaged on frequency response costs.
NGESO	WP7: Communication	Investigation of the information systems needed to interface with the MCS and its impact on the data flow across the communication network

Table 1: EFCC project partners and their areas of expertise

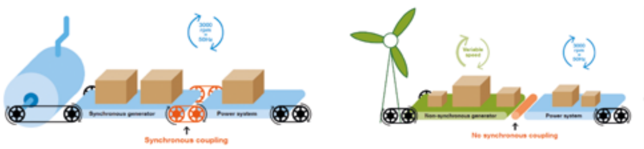
Further information on how each partner has supported and contributed to the EFCC project is available in Appendix A.

Executive summary

Project background

As Great Britain's (GB) electricity sector becomes increasingly decarbonised, traditional thermal power stations are closing and a rising number of inverter based technologies, such as wind and solar photovoltaic (PV), are connecting to the network. This creates several operability challenges, one of which is reducing system inertia. Thermal power stations have traditionally provided system inertia, which acts as a natural aid to maintaining system frequency, so removing them from the system will impact how frequency is managed. System frequency is a measure of the balance between electrical power generated and consumed. In GB, the electricity system frequency is nominally 50Hz and the National Electricity Transmission System Operator (NETSO) balances generation and demand in real-time.

System inertia is a characteristic of the electricity system that provides system robustness against frequency disturbances. It is a result of the energy stored in the rotating mass of electrical machines (i.e. generators and motors).



As more renewable energy technologies, such as wind, solar PV and other converter based technologies (e.g. interconnectors), are connected to the electricity transmission network, there will be a corresponding reduction in system inertia. This is because these technologies are not directly coupled to the electricity system so do not contribute to providing inertia, as shown in Figure 1.

Figure 1: System inertia

Lower system inertia means that after a frequency disturbance, there is a faster rate of change of frequency (RoCoF). This increases the unpredictability and volatility of system frequency movement across the network immediately after an event. Consequently, the speed, volume and degree of coordination of frequency response must increase to keep frequency within acceptable parameters.

Project scope

In 2014, NGESO, (under the licensee name of National Grid Electricity Transmission, NGET), supported by six commercial and two academic partners, submitted a proposal for the EFCC project under the Network Innovation Competition (NIC) mechanism. Ofgem approved the proposal and issued the Project Direction on 19 December 2014. The project was originally scheduled to run from January 2015 to March 2018, but was later extended to January 2019. This extension allowed additional time to capture and analyse data from the commercial field trials and complete further testing to support any potential implementation.

The project's main aims were to develop a monitoring and control system which manages system frequency in a low inertia electricity system and to quantify the technical capability of a range of service providers to deliver faster acting frequency response. The project scope focused on three key areas to meet the core objectives:

i) **Develop a wide area monitoring and control scheme (MCS)** to manage frequency response in a low inertia electricity system. This goal was to develop and validate the MCS and reconfirm the system need for a coordinated fast response on the electricity network.
ii) **Technical capability for faster frequency response** from a range of service providers. This objective also considered how the MCS would interface with different service providers, including communications protocols and site configurations.
iii) **Development of new EFCC (RoCoF-based) frequency response balancing service.** How the MCS would interface with NGESO's existing business systems, applications and processes also formed part of this outcome, to determine how the system could be incorporated into business as usual activities.

Project outcomes

The aim of the NIC EFCC project was to develop and demonstrate an innovative new monitoring and control system which obtains accurate frequency data at a regional level, calculates the required rate and volume of very fast response and then initiates the required response within 0.5 seconds of a system frequency deviation. The project was also tasked with determining the technical capability of different service providers to deliver faster acting frequency response and identify how renewable technologies can increase their participation in a frequency response market.

From an electricity system perspective, the MCS concept would allow the network to operate with increasing volumes of non-synchronous generation and at lower levels of system inertia. The project also facilitates NGESO's ambition to operate a zero carbon power system by 2025 by providing an adaptable control platform which can coordinate and access the response capabilities from a range of non-synchronous technologies.

Seven dedicated work packages were designed, each with their own set of objectives, to collectively achieve the overall project objectives, as shown below in Table 2.

Work package (WP)	Section description
WP1: Monitoring and control system	Design and implement a wide area control system into physical hardware
P2: Assessment of the response of different providers	The MCS is interfaced with a range of technologies and trialled to establish rapid frequency response capability
WP3: Optimisation	Evaluating the system benefit of wide area control methods
WP4: Validation	Systematic testing of the MCS to confirm its robustness
WP5: Dissemination	Knowledge sharing of project learning through a variety of communication channels
WP6: Commercial	Create a new balancing service allowing immediate roll-out of the enhanced frequency control capability and achieving the savings envisaged on frequency response costs
WP7: Communications	Investigation of the IS systems needed to interface with the MCS and its impact on communication network data flows

Table 2: EFCC project work packages

Objectives successfully met
The main objectives of the project were aligned to several Successful Delivery Reward Criteria (SDRC) milestones. The following were successfully met and are discussed in detail in Chapter 5 (Performance compared to original project aims, objectives and SDRC deliverables).

Activity successfully completed	Outcomes
Formal contract signed by all partners	• Formal EFCC contract signed by all partners • Agreements in place with DSR customers
Monitoring and control system developed successfully	• Application development: Event detection algorithm completed • Application development: EFCC resource allocation algorithm completed • Application development: Optimisation algorithm completed • Application development: Testing completed • Application development: Revision completed • Control platform development: Specification completed • Control platform development: Development completed • Control platform development: Controller testing completed • Control platform development: Revision completed
Storage decision point	• Recommendation report made to Ofgem
Response analysis from service providers	• Demand side response • CCGT power stations • Solar PV power plant • Solar PV power plant and battery storage hybrid device[1] • Wind farms
Successful knowledge dissemination	• Knowledge sharing e-hub delivered • All non-confidential data and models developed as part of EFCC were shared on the e-hub • Annual knowledge dissemination activity was organised
Project close and knowledge dissemination	• The control systems required for the commercial trials were demonstrated and validated • The response capability of the type of services described were trialled • MCS validation exercise was carried out • Knowledge dissemination events were carried out and results shared and made available

Table 3: SDRC milestones successfully met

[1] Battery trials were funded through Network Innovation Allowance (NIA)

Objectives not successfully met
An account of activities outlined in the original project scope which did not progress is detailed below, along with the reasons why.

Activity not successfully completed	Reasons for outcome
New enhanced frequency response service developed successfully	Since the bid submission, significant changes to the energy landscape impacting system requirements presented newer operational challenges. This has led to the business shifting its focus from the development of a single EFCC product to developing a suite of new, faster-acting frequency response products incorporating the learnings from the EFCC project
Response provided will be optimised	This task was superseded by additional simulations which determined the requirement for wide area control schemes and identified the optimal method for implementing such control schemes
New balancing service is developed in collaboration with EFCC partners, other service providers and NGESO's commercial operation department	NGESO determined that it would not be appropriate to progress with the development of a standalone EFCC balancing service product in line with 2017 SNAPS proposals

Table 4: Objectives not successfully met

Financial performance
The original project budget of £9.6m (including partners' contributions), was modified to accommodate Ofgem's decision to exclude the funding of a new battery storage unit. This reduced the overall budget by £1.1m (including partners' contributions) with the regulatory and licensee funding contributing £7.0m to the revised total project budget of £8.5m (including partners' contributions).

The project was successfully delivered within the revised allocated budget with the underspent regulatory funds to be returned in accordance with the Electricity Network Innovation Competition Governance Document. This includes the amount ringfenced for the development of a new EFCC frequency response product.

Main learning generated by the project
The EFCC project has successfully developed, tested and demonstrated a wide area monitoring and control system (WAMCS) and confirmed the technical capability of fast frequency response from a diverse range of potential service providers. Ultimately, this has built confidence in the technology and provided a road map for any potential future implementation of a WAMCS on the GB electricity network.

Learning and opportunities generated throughout the project are summarised below and detailed further in Chapter 4 (Outcomes of the project).

System need for coordinated fast frequency control
- Frequency moves faster following a frequency event in lower inertia systems. Maintaining system frequency stability will require response from a wider range of service providers to act more quickly to manage the frequency deviations.
- Frequency is changing differently across the network following an event (within the first second) with regional variations in system frequency. Faster service providers responding to local frequency measurements alone will no longer be sufficient, due to the regional frequencies that are apparent after a system event.
- RoCoF is a quicker way to detect and respond to faster frequency changes. Any RoCoF-based response needs to be managed with a view of how the frequency is changing across the NETS to determine how to deploy the response more effectively.
- To manage faster changing frequency, control methods will require access to real-time system data to calculate the energy imbalance on the network and deploy response in a proportional way.

MCS development and performance validation
A wide area monitoring and control system (MCS) was developed to deliver coordinated fast frequency response.

The MCS delivers sub-second detection and triggering of response from multiple resources to system frequency events in a coordinated manner that optimises their performance characteristics. This potentially allows more technologies to access a fast frequency response market which will be increasingly important in low system inertia conditions.

A new hardware platform that could perform fast, real-time and deterministic control functionality was developed and successfully interfaced with the different control systems at commercial sites. Changing the MCS design from a centralised to decentralised approach improved robustness and mitigated against a single point of failure.

Confidence level – to achieve 90% confidence that the MCS can maintain wide area visibility to make correct decisions for 500ms after an event, the communications network jitter needs to be kept to 10.2ms for a mean latency of 60ms, and 13ms for a mean latency of 50ms.

Validation process – a robust methodology was developed for testing and validating a wide area control system. This could be applied to other wide area systems or complex active network management systems.

Technical capability for faster frequency

- Demand side response – the project developed and tested three new demand side services: Static RoCoF, Spinning Inertia and Dynamic RoCoF. Static RoCoF and Dynamic RoCoF can both detect and respond to MCS signals for real events on the transmission network with appropriate control system settings. Delivery within the target 0.5 seconds is also achievable for the Dynamic RoCoF. For Spinning Inertia sites, the governors may respond too quickly and counteract response to frequency deviations; alternatively, they could be given a control signal derived from locally-measured RoCoF to trigger the response. Confirmation that Static and Dynamic RoCoF sites have suitable operational characteristics for taking part in any potential RoCoF service if it is economically advantageous for them to do so.

- Combined cycle gas turbines – confirmation that they can respond more quickly to rapidly falling network frequency by responding to RoCoF instead of a deviation in frequency from a set point (normally 50Hz). It was determined that a faster frequency response from large thermal plant is achievable, so primary response delivered at 10 seconds can be delivered approximately three seconds quicker and sustained to meet network requirements.

- Wind – demonstrated capabilities of wind power plants to participate in fast frequency control (target time of 0.5 seconds is achievable). Tests combined with portfolio analysis showed the potential to harness inertial response that can increase wind turbine generation for a short period without prior curtailment. However, there is a wind speed-dependent recovery period so it is important to consider any potential second frequency dip. The optimisation functionality in the MCS allows the response from other service providers to be coordinated to compensate for the wind recovery period.

- Solar PV (and battery storage hybrid) – demonstrated that the provision of +/-frequency response services from central, inverter-based solar PV plant is possible. Limitations include curtailment for the provision of positive frequency response, day/night availability, asymmetric inverter response times, flat ramp rates and the volatility of available power, resulting in slow response time. For 2014 central converter-based solar farms, it is necessary to update the communication system and retrofit the PV farm with a good network design and fast switches to provide fast frequency response. A hybrid solar PV and battery unit can provide additional frequency response support. A potential combined operating regime of solar PV and battery could have the battery providing the fast reaction part of an overall response.

Value of coordinated fast frequency control

- The cost benefit analysis (CBA) identified potential savings in both Steady State and Consumer Power future energy scenarios. Potential savings are made by reducing the amount of market invention required by the NETSO to balance the system. Savings will be offset by the cost of implementing and maintaining the MCS.
- Accessing the potential significant benefits will require enhancements to the MCS, access to real-time operational data and development of the appropriate commercial framework and IS interfaces.

The original project proposal to develop and implement an EFCC (RoCoF-based) frequency response product did not go ahead. Since the project started, there have been significant changes to the energy landscape, impacting system requirements and presenting new operational challenges. This has led to the business shifting its focus from developing a single EFCC product to developing a suite of new, faster-acting frequency response products incorporating the learning from EFCC. The associated regulatory funds will be returned in line with the Electricity Network Innovation Competition Governance Document.

Planned implementation

A phased approach to any potential implementation of the monitoring and control system (MCS) is advocated over the period out to 2025. This approach will include a full assessment of the how the MCS will operate on the live electricity system which will help to increase the technical readiness of the system before any potential roll-out. Consideration must also be given to the new commercial framework and IS interfaces with National Grid Electricity System Operator's (NGESO) balancing systems before any implementation to understand the impact and necessary interfaces.

In addition to fully unlocking the benefit and utilising the coordinated approach offered by the MCS, increased ability to model the dynamic system behaviour along with greater visibility of real-time system measurements (including system inertia) is needed. This is especially important with lower inertia systems and potential within day frequency response procurement strategies.

The MCS is dependent on having access to operational data of the system performance. As such, reliable and accurate system inertia values and real-time system performance data is fundamental to any potential utilisation of the MCS within an operational environment. This will require continued development to improve NGESO capabilities and closer collaboration with network licensees in order to agree strategies and associated timescales.

Impact assessment of the MCS on operational systems

- Implementation of the MCS would require consideration of critical operational aspects. These include PMU weighting, inertia calculations, interfaces to the control room and the settlements processes.
- The current design of the MCS could require a significant volume of data transfer across the communication network, with information being shared between all the Local Controllers and Regional Aggregators. The specific volume of data will be dependent on the number of PhasorControllers and the MCS roll-out strategy.
- Cyber security vulnerability assessment of the PhasorControllers that make up the MCS showed there are no major weaknesses to the control platform and supporting software.
- Phased approach to any potential implementation of the MCS is needed. This will include a full assessment of how the MCS will operate on the live electricity system, which will help to increase the technical readiness of the system before any potential roll-out.

Main learning derived from the method(s)

Innovation projects inherently experience challenges and risks that would not be associated with business as usual activities. For this project, a number of challenges arose from the original setup and methods adopted; considerable learning has been achieved in these areas. Learning generated from the methods adopted is summarised below and further detailed in Chapter 9 (Lessons learnt for future innovation projects).

- Project milestones and work packages should be flexible to achieve the project's overall objective in response to project findings or changes in the landscape – the EFCC project adapted and identified aspects that required further development that were unforeseen at the outset. By carrying out additional initiatives, the project was in a stronger position to deliver a successful outcome.
- Forward thinking – within the project objectives it is advisable to consider potential market changes during the project, along with broader solutions to market challenges.
- Working collaboratively – innovation projects require a strong ability and willingness to work through ambiguity and change. Making sure the project team comprises collaborative and motivated people is essential to deliver the project's objectives.
- Staying within project scope – clear and efficient communication to the business/project team when there is a risk of 'scope creep'. Clear identification of change requests and strong project management is essential.

Details of the work carried out

The project evaluated and determined the network benefit of implementing a wide area control system (WACS). GE Renewable Energy designed and developed a monitoring and control system (MCS) into physical hardware that was tested and validated against future energy scenario conditions. In parallel, alternative WACS approaches (based on the proposed GE Renewable Energy solution), were developed to offer a comparison with the MCS and ascertain their associated merits for operating the electricity system.

Alongside the development and testing of the MCS, the project also evaluated how the control system would practically interface with different service providers including communications protocols and site configurations. The technical capabilities of different service providers were also evaluated for the provision of fast frequency response. How the MCS would interface with existing business systems, applications and processes was also considered to identify how it could be incorporated into NGESO's business as usual activities. Part of this assessment included a detailed evaluation of the communications architecture to understand the implications and data requirements to support the MCS.

The potential monetary savings were re-evaluated based on the performance of the MCS and the actual capabilities of each of the technologies. This re-evaluation would confirm whether the original project benefits remained applicable given the changes in the electricity sector since the project commenced.

Given the extensive scope of the project, the technical aspects have been categorised into the following work packages as shown in Table 5.

System need for coordinated fast frequency control

An assessment of the need for fast, coordinated and targeted frequency response in lower electricity system inertia conditions was completed. To achieve this, alternative wide area control methods were developed and simulations completed to ascertain the relative benefits of each control method in operating the electricity transmission network. By evaluating each control method, the specific system conditions were identified when a particular control technique could no longer manage high rate of change of frequency (RoCoF) and other control approaches would be needed. The assessment also determined a potential implementation path for a wide area monitoring and control system in Great Britain (GB).

This section outlines the approach to this assessment.

Frequency containment for low inertia systems

Frequency response is managed using local measurements that provide either a static or dynamic response relative to the absolute value of frequency. Each service provider acts independently to deliver an incremental change in generation or consumption.

Figure 2 illustrates that the system frequency is not the same across the National Electricity Transmission System (NETS) at the time of a frequency event. It is possible to manage these variations in system frequency using only local measurements, as the current levels of system inertia

Work package (WP)	Section title	Section description
(WP3): Optimisation	System need for coordinated fast frequency control	Evaluating the system benefit of wide area control methods
(WP1): Monitoring and control system	Monitoring and control system development	Design and implementation of a wide area control system into physical hardware.
(WP4): Validation	Monitoring and control system performance validation	Systematic testing of the MCS to confirm its robustness
(WP2): Assessment of the response of different providers	Technology assessment for fast frequency response with the Monitoring and control system	The MCS is interfaced with a range of technologies and trialled to establish rapid frequency response capability
(WP7): Communications	Impact assessment of the MCS on operational systems	Investigation of the information systems needed to interface with the MCS and its impact on the data flows across the communication network
(WP6): Commercial	Value of coordinated fast frequency control	Cost benefit analysis to estimate the future benefits from a coordinated fast frequency control approach

Table 5: Summary of the technical project work packages

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(≥130GVAs) are high enough to maintain grid stability immediately after a frequency event.

However, in lower inertia systems the frequency moves faster after a frequency event (within the first second as shown in Figure 2). To maintain system frequency stability with higher RoCoF, response providers have to act more quickly to manage the frequency deviations. Frequency is also changing differently across the system, with regional variations. But service providers responding more quickly to local frequency measurements will not be enough because of the regional variations after a system event. This could deliver an under or over response, which could lead to system instability.

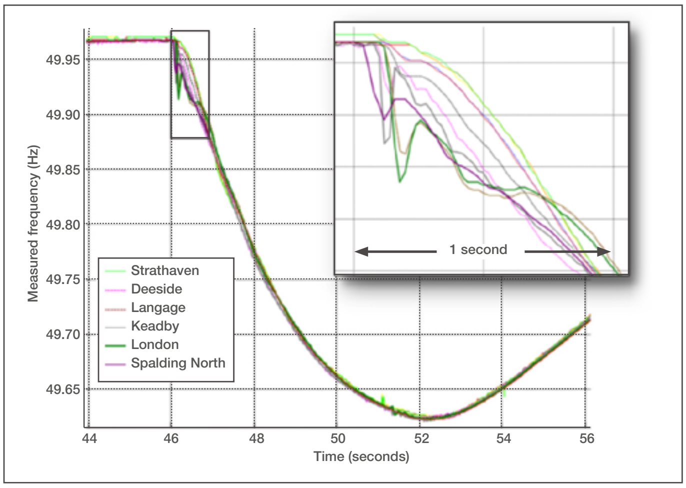

Figure 2: Variation in system frequency within the first second after a frequency event

Another way to manage system frequency is to use RoCoF as a quicker way to detect and respond to faster frequency changes. This RoCoF-based response needs to be managed with a view of how the frequency is changing across the NETS to determine how to deploy the response more effectively. Wide area measurement techniques can provide a real-time view of frequency. To manage faster changing frequency, control methods that use this real-time data can calculate the energy imbalance on the network and deploy response in a proportional way.

Analysis approach

A 36-bus DIgSILENT PowerFactory model representing the NETS (Appendix B) was used to simulate lower inertia systems. Conventional static and dynamic response was modelled and its performance for frequency containment quantified. Faster service provider models were developed and incorporated into the DIgSILENT model for the assessment.

Three alternative control methods were developed using DIgSILENT programming language that considered how a wide area control system would:

- measure and identify a RoCoF
- calculate the energy imbalance during a system frequency event
- modify the output of service providers, and
- manage the frequency deviation after a system frequency event.

DIgSILENT programming was used for each control method to represent real-time data measurements of electrical parameters on the NETS. A front-end user interface was also developed to allow the settings for the control methods to be modified; for example, RoCoF measurement time, availability of response and communication delays.

The alternative control models developed allowed the effect of wide area techniques for frequency control to be compared with the static and dynamic responses used today. The analysis simulated the loss of generation from different network locations to identify how effectively the control methods detected regional changes in RoCoF and how well the response worked.

Control method principles

The three control methods developed and illustrated in Figure 3 were:

- real-time targeted control – which approximates the operation and performance of the MCS developed by GE Renewable Energy
- real-time distributed control – where resources are deployed evenly across the network, irrespective of the event's location
- system state targeted control – where the picture of system inertia before the event is used to ensure a degree of coordination in deploying resources within a zone, based on the system frequency and RoCoF during the event. It is recognised that system inertia will differ before and during an event, however this method relies on the difference being small enough to still effectively deploy response.

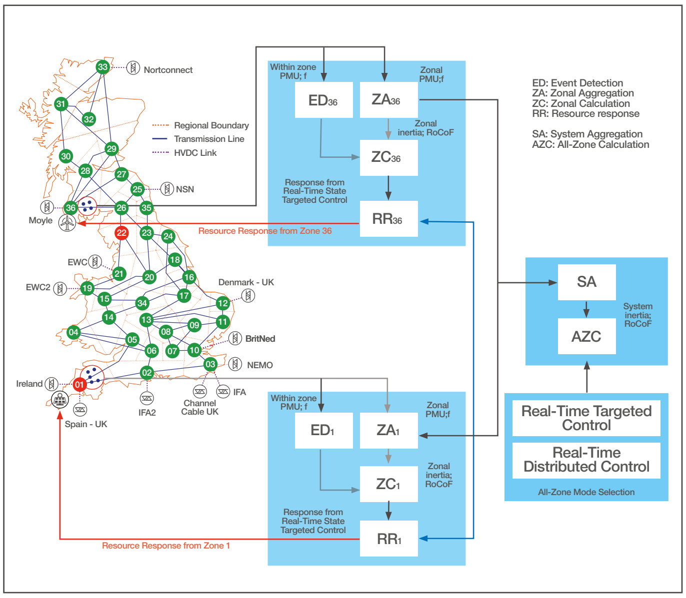

Figure 3: Real-time targeted control, real-time distributed control and real-time state targeted control techniques

Wide area simulation tests

The wide area control methods were tested against a number of system conditions. The tests were developed to quantify the application of the control approach and determine the system benefit. Table 6 tabulates the simulation tests.

Activity successfully completed	Outcomes
1,560 MW loss of generation in south west England for scenario year 2020/21	Compare the real-time state targeted control, real-time distributed control and real-time targeted control methods
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of the number of samples for RoCoF calculation on all the control methods
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of communication times using real-time state targeted control method
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of communication times using the real-time targeted and distributed control methods
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of resource response rates using the real-time distributed control method
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of the allowable maximum resource response of each zone using the real-time distributed control method
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of the amount of fast, coordinated response available (i.e. effective loss of generation estimation factor) using the real-time distributed control method
925 MW loss of generation in south west England for scenario year 2020/21	Investigate the impact of RoCoF threshold in real-time state targeted control method
Three-phase short-circuit fault followed by load loss (large amount of 1000 MW) in low inertia zone 13 for scenario year 2020/21	Investigate the transient stability of all the control methods
Three-phase short-circuit fault followed by load loss (large amount of 1000 MW) in low inertia zone 13 for scenario year 2020/21	Investigate the ability of fault/event detection block for all the control methods
Three-phase short-circuit fault followed by load loss (large amount of 1000 MW) in low inertia zone 13 for scenario year 2020/21	Investigate the resource frequency response speed for all the control methods
Loss of generation of 1000 MW in low inertia zone 13 for scenario year 2020/21	Investigate the impact of unbalanced resource allocation for all the control methods

Table 6: List of conducted baseline tests in DIgSILENT PowerFactory

In addition to the tests above, sensitivity analysis was also completed that included varying the size of the generation loss and its location, speed of response and RoCoF. Full details are described in the "*Modelling and Study of Wide-Area Monitoring and Control Methods using 36-Zone GB Model in PowerFactory*" report that is available on the project website.

Chapter 3

Monitoring and control system (MCS) development

GE Renewable Energy developed the monitoring and control system (MCS) that can be used to initiate a fast frequency response. The system consists of a real-time wide area monitoring function for analysing the power system and a control element that will use this information within 500ms to produce fast, targeted, predictable and coordinated frequency response. It built on the extensive experience of wide area monitoring within GE Renewable Energy and the learning outcomes from the NIC VISOR (Visualisation of Real Time System Dynamics using Enhanced Monitoring) project. The system was designed to allow any service provider (irrespective of size, location and type of technology) to interface with the MCS.

The predicted decline in system inertia means that frequency response must be deployed in a faster and more coordinated way than it is today. Using a wide area control approach will address this. The rationale for using wide area control is described below.

The purpose of a wide area control scheme

During a frequency event, there is an imbalance between active power produced and active power consumed on the GB electricity system. For the wide area control system to respond effectively it must identify a genuine frequency event arising from a mismatch of active power, in comparison to a network fault condition that may also give rise to a frequency oscillation. Figure 4 shows a local measurement from the GB electricity system during a line disconnection. The oscillation in frequency lasts for approximately three seconds then stabilises to a frequency similar to that before the event. If a wide area control system responded quickly (within 500ms) based on the measurement of this system fault, it could cause frequency instability.

Also, within 500ms, wide area control systems need to consider:

- comparing local measurements with measurements across the whole system, because local system measurements do not provide enough information to identify the cause of a deviation that might be due to a system frequency event elsewhere on the network
- regional variations in system frequency as mentioned earlier in this chapter.

In addition, wide area measurements from across the network can also identify where the frequency event occurred by detecting the largest frequency deviation on the network. This could allow frequency oscillations to be reduced by targeting response closest to the event's location.

Monitoring and control scheme principles

In developing the MCS the key concepts of a wide area control system have been incorporated and discussed below:

- to manage system frequency after a frequency event as quickly as possible
- to account for regional variations by deploying response in a targeted way to minimise system instability
- using Phasor Measurement Units (PMUs) for real-time measurements.

Managing system frequency as quickly as possible

A reduction in system inertia will have a corresponding increase in the speed of frequency movement, which will also differ across the network immediately after the frequency event. This means the frequency will have to be managed more quickly, along with the deployment of any response. To contain frequency in lower inertia systems, another way of responding to frequency events is to base the response trigger on RoCoF rather than an absolute value of frequency.

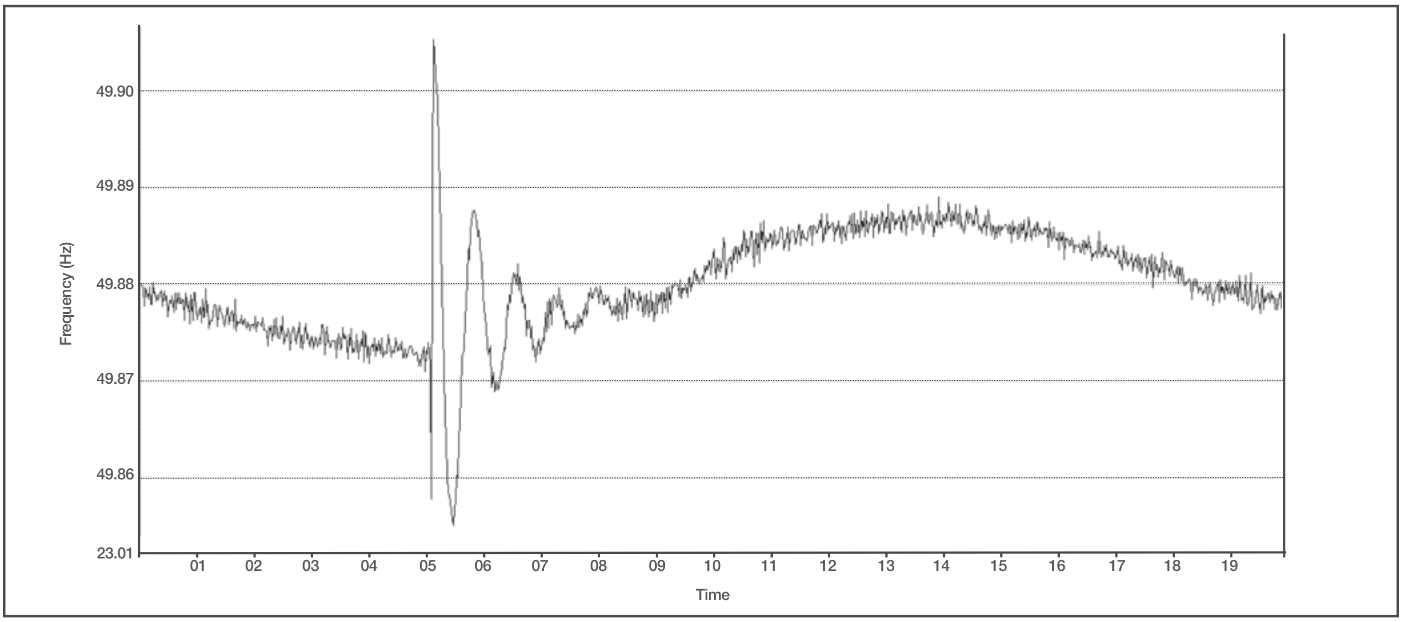

Figure 4: Frequency measurement from GB WAMS as a result of line trip

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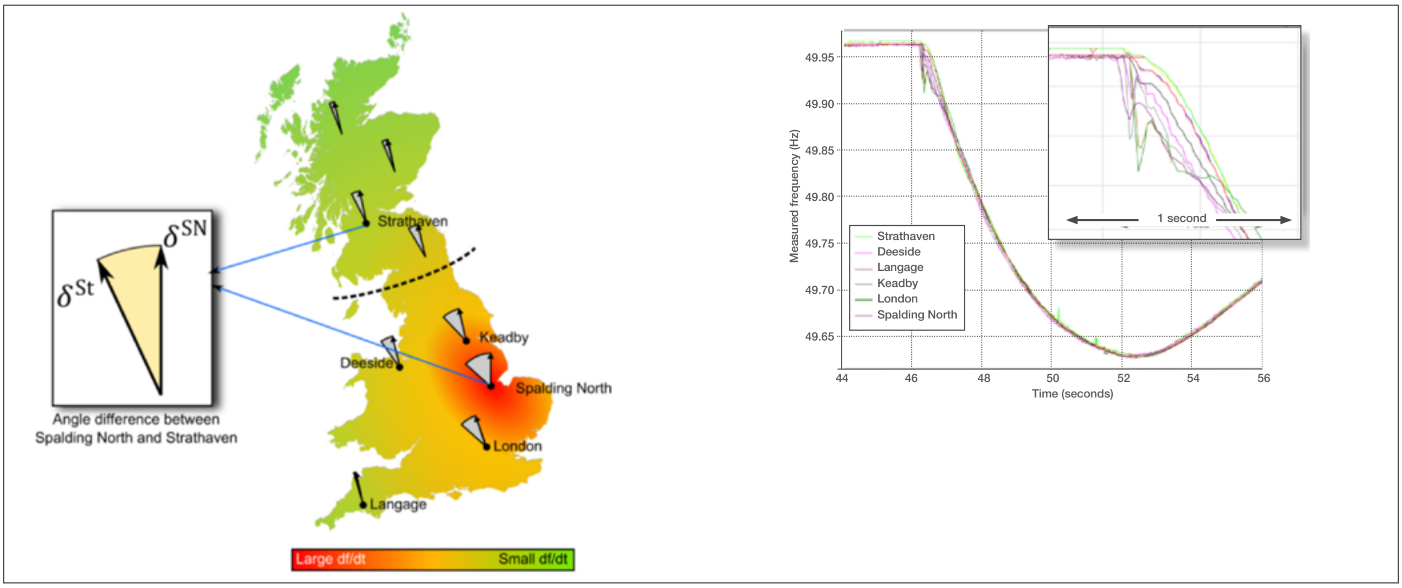

Figure 5: Phase angle behaviour after loss of generator

Figures 6a and 6b show possible angle behaviour where phase angles increase relative to their pre-fault states, because of the increased power flows and loading of the remaining generators connected to the network.

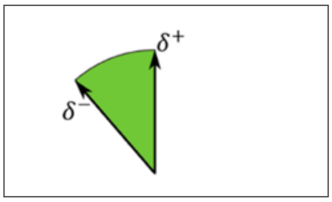

Figure 6a: Angle behaviour after event

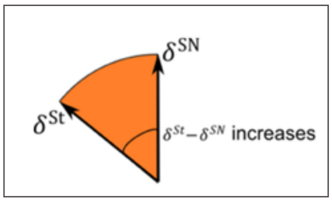

Figure 6b: Angle difference across the system

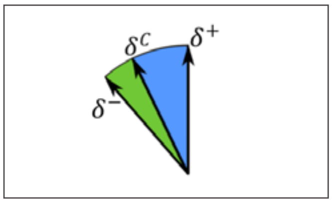

Figure 7a: change of angle

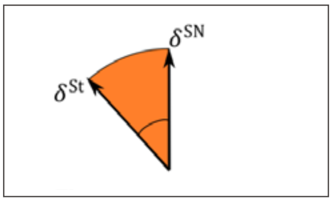

Figure 7b: angle difference across system

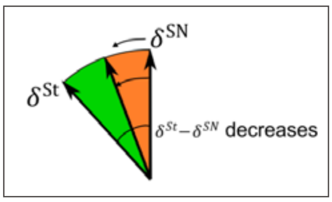

Figure 7c: positive control action

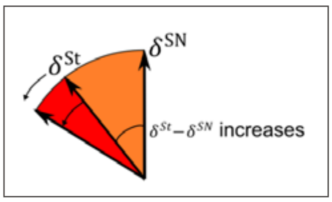

Figure 7d: negative control action

Regional frequency variations and phase angles

Figure 5 shows the behaviour of the NETS in response to a loss of generation at Spalding North. The rate at which the system frequency drops depends on the level of system inertia at the time of the frequency event.

Immediately after the loss of generation, the regional variations in system frequency are caused by the inertia in that area and proximity to the event, as shown in Figure 5. The effect on frequency variations caused by proximity to the event is seen through the change in system phase angle: phase angles closer to an event will change more than those further away.

The MCS aims to instruct service providers across the system to contribute towards the energy imbalance that occurs after a frequency event. If service providers closest to the frequency event contribute to the imbalance, the phase angles between regions will reduce and less power will flow across the network.

Consider the angle difference between two locations that has increased due to a system frequency event (and shown in Figures 7a and 7b) which show the change in angle and the angle difference. If the response to the frequency event is met locally, the angle difference will decrease, as in Figure 7c, providing stability to the system. If the response is actioned further away from the location of the frequency event, the overall angle difference across the system will increase as in Figure 7d, potentially leading to system instability.

These changes in phase angle are also linked to how power flows across the network. If the phase angle increases, this indicates that there is a higher power flow between locations. If the angle difference becomes too large, the risk of the system splitting greatly increases. It is important for the MCS to minimise the energy imbalance and take into account where the response originates from to mitigate against potential thermal instability.

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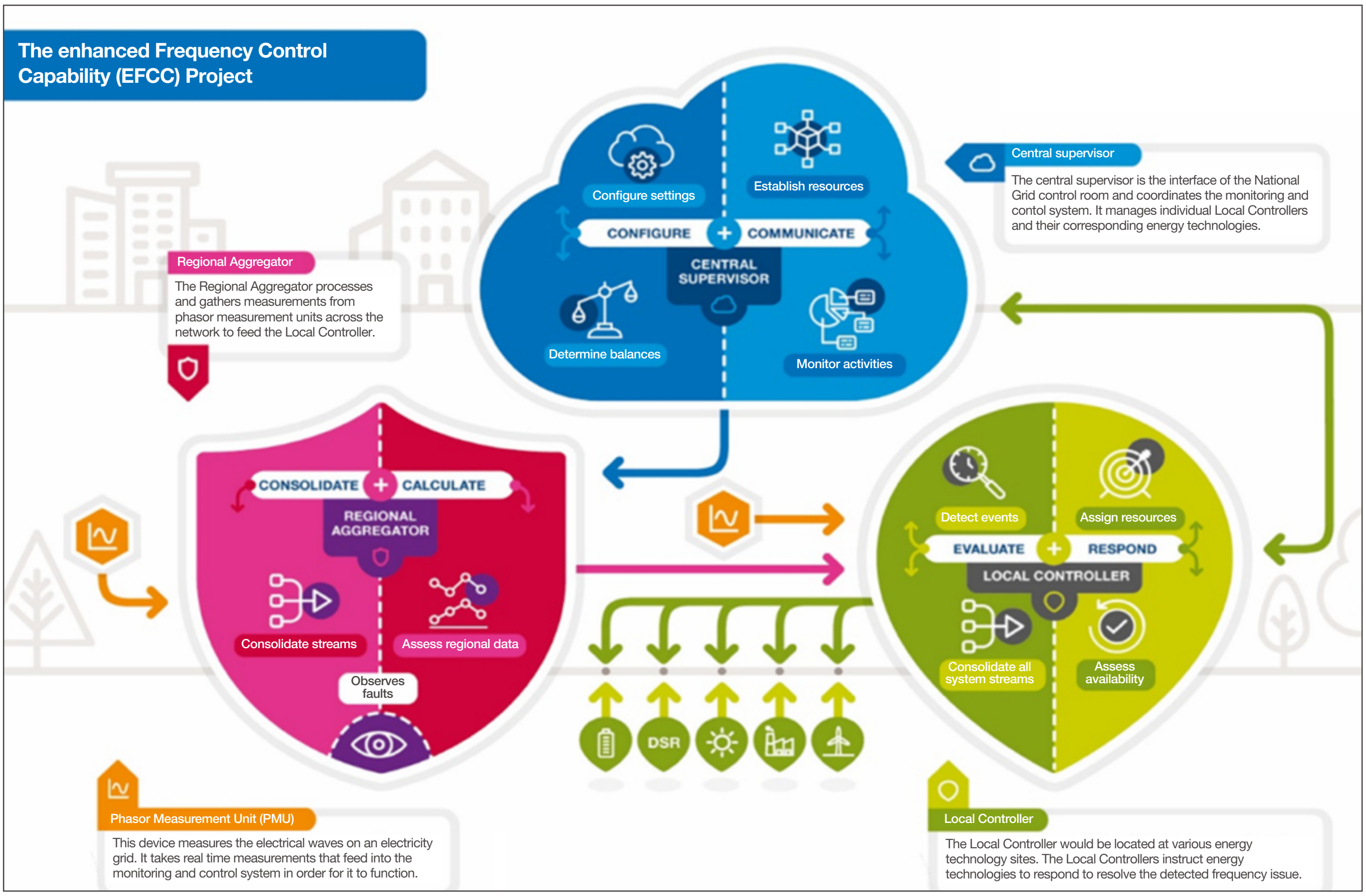

Figure 8: Monitoring and control system

Targeting frequency response

The network can be divided into several regions to provide a locational element to the response to increase system stability and prevent system separation. These regions will be based on coherency where everything within a region should be electrically tightly coupled. The topology of the network can change under different scenarios and this must be considered when defining a region. The definition of a region will affect the performance of the MCS and how it deploys response close to the frequency event.

Using Phasor Measurement Units

Phasor Measurement Units (PMUs) can be used to gather measurements of the electrical parameters on the network in real time. A concept has been developed so that PMU measurements are used to capture how system inertia varies in a region. In this concept, PMU signals within a region are weighted based on modelled or measured inertia values. This allows the relative differences in inertia between the sizes of generation connected to the network to be represented.

For example, consider two PMU signals, one connected to a large generator and the second to a smaller generator. During a frequency event, the small generator with less inertia will move faster relative to the larger generator. However, the overall behaviour on the network is dictated by the inertia of the larger generator. If weights are assigned to each of the PMU signals, weighted averaging can be used so that the signal corresponding to the larger generator would have more of an effect on the averaging output, better representing the overall system. To implement this in the MCS, weights are assigned to each of the PMU signals.

How the MCS uses the weighted signals from PMUs is described in the following section.

Monitoring and control scheme

The MCS was designed with three functional component parts, as shown in Figure 8, which carry out the following performance requirements:

- calculation of RoCoF and initiation of frequency response within 500ms from service providers
- quantification of the total frequency response size and coordination of fast the response with governor response
- deployment of slower acting frequency response must not jeopardise the stability of the power system
- the control system must give equal market access to multiple service providers.

Central Supervisor

The Central Supervisor (CS) provides the coordination role for the MCS. It receives operational data from service providers and, based on the system inertia levels and RoCoF, coordinates the amount of response to be deployed.

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To do this the CS needs:
- system inertia levels
- maximum system loss
- availability of response from each service provider, including availability status, MW available, ramp up and down characteristics and for how long the response can be sustained (including any recovery period).

The CS gathers information from each of the service providers to form a combined portfolio of available response connected to the MCS. This portfolio for frequency response is prioritised based on the speed of response and issues the prioritisation list to each Local Controller.

Regional Aggregator
The electricity network will need to be split into geographical regions, each containing one Regional Aggregator (RA) and several PMUs. The RA gathers data from the PMUs within the region and aggregates the signals to produce an equivalent frequency and phase angle value for that region. The PMU weights (as previously described) are set within the RA to account for any inertia measurement that is lost at the time of the frequency event. This allows the MCS to more accurately calculate the response required due to the changes in system inertia. The RAs send aggregated signals to the Local Controllers to verify whether frequency events detected at a local level need to be responded to.

Local Controller
Each Local Controller (LC) calculates response to the frequency event autonomously to minimise any delay in the service provider delivering the response. Every LC sees the same ‘picture’ of the power system by receiving the same data at the same time (via the RAs). This allows them to act in a coordinated manner. This picture of the wider system is updated during an event and compared with local measurements.

The resource deployment (i.e. how much each LC should request from the provider to meet the energy imbalance) is coordinated using the information from the CS. This information will be based on the amount of response each controller has access to, and the proportion of the total regional response it can deliver. The LC will receive data from the CS regarding which region it is in, the total amount of response available in that region and its relative position in the resource portfolio. Each LC can compare the total required response from the region to the available response in the region, to determine its contribution.

As response is being deployed during a frequency event, the LC can assess the effect on the overall system frequency. The LC can modify the allocation of the service providers towards frequency response in real time. This is valuable in terms of maintaining the overall energy balance on the network in low inertia conditions. If the system frequency still needs to be contained, and resources have been depleted in a region, the LC can request further response to be deployed from other regions. This approach is beneficial when there are successive frequency events (for example cascade generation loss).

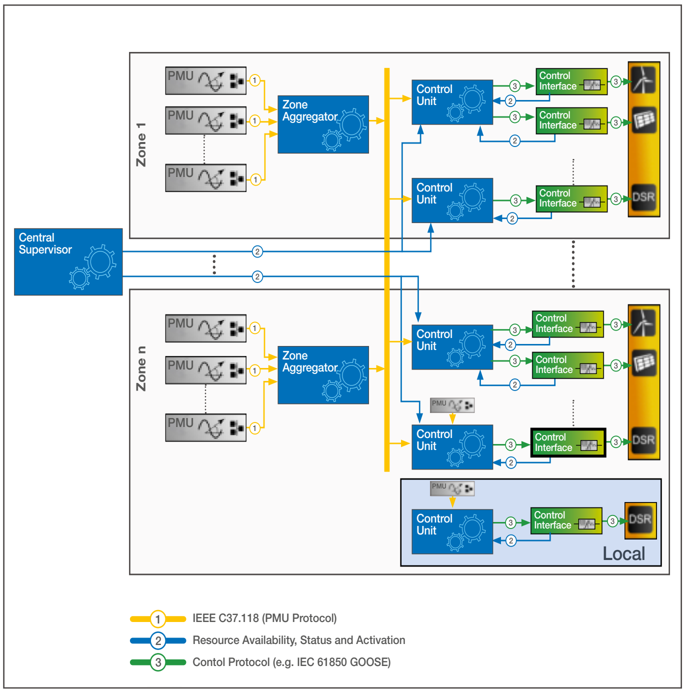

Figure 9: Communications links for the monitoring and control system

Monitoring and control system communications
The provision of faster, coordinated, targeted frequency response depends on appropriate communications architecture. Figure 9 shows the communications links (data streams) between the component parts of the MCS.

Figure 9 shows the two key data streams used in the architecture. The fast data stream (between the LCs, RAs and PMUs) is shown in yellow and the relatively slower data stream between the LC and CS is shown in blue. The fast communications data stream from PMUs to RAs provides high resolution data of the power system with a 20ms data rate. Local measurement devices (which can be PMUs) required by each LC will also use the same communications data stream. The slower communications data stream carries service provider data between the LCs and the CS. This data flow can be much slower than the 20ms data rate of the fast communications stream, as its main function is to capture the changes in service provider availability.

Creating a fast and slow communications hierarchy means that priority is given to the measurements required for control, while the pre-event coordination exchange to the CS can be updated more slowly (potentially every 15 minutes).

The LCs receive the real-time data from the RAs to assess the state of the power system and deploy the necessary response from service providers. The deployment of response is coordinated based on the information exchanged between the LC (which receives service provider data) and the CS. When a system frequency event is detected it will use the most recent data received by the CS, as opposed to waiting for data from it once the frequency event has happened. It is anticipated that data exchanges of 1s resolution or lower would be enough to capture changes in weather dependent generation.

Figure 9 also shows a control interface between the controllers and the service providers. As the aim is to be open to all technologies, there will not be a common communication protocol between the LC and a service provider. The control platform used for the MCS is suitably adaptable to accommodate a range of communications protocols, including those not tested by the project.

More detail about the data structure of the MCS is available in Appendix C.

Modes of operation
The control scheme operates in two forms. The wide area control mode will be the normal state of operation for the MCS, which means all the communications links between the components and PMUs are functioning. If there's not enough wide area visibility from the RAs to an LC, the LC can resort to a fall-back mode of operation (local control).

Wide area control mode
This is the normal mode of operation for the MCS to deliver a fast, targeted frequency response. In this mode, the LC has access to the wide area measurements from the RAs, as well as the local measurements. The frequency data received from each of the RA regions is aligned in each LC to produce a system-wide equivalent. Each LC can compare its own local frequency with the wider system frequency during an event to know if response needs to be deployed within its own region. If the local frequency is moving faster than the wider system frequency, the LC knows that it is located close to the frequency event.

Local control mode
In the local control mode, the LC cannot see enough of the wide area measurements and will rely solely on the locally installed PMU (or similar measurement device) for frequency data to operate in a more limited capacity. Frequency measurements taken from a single location will not have the benefit of combining with the weighted information from the Regional Aggregators and will have a noisier signal. To prevent the LC from responding to the oscillatory signal (which may cause spurious tripping), the frequency signal must be filtered using a low-pass filter to remove the effects of inter-area oscillations. The frequency detection methods and response from the LC will be based on the local filtered frequency measurement. This will be slower (up to 0.5s), but can still be useful for frequency response.

Reliability and robustness
The MCS has been designed for performance reliability and robustness. The concept of graceful degradation has been incorporated into the design so the system will continue to operate in the event of a single component failure with a reduced level of performance using the remaining available components.

The reliability of the MCS also considers data quality and communication issues such as limited or missing data packets, or complete failure of a communication link. Each of the algorithms used in all the control components has logic that considers quality of the data in every process step.

These data aspects have been validated and are discussed in the "MCS Performance Validation" sections of Chapters 3 (Details of work carried out) and 4 (Outcomes of project) report.

MCS control platform infrastructure
A control platform was developed called a PhasorController (PhC), which is a hardware platform that can be used within a power system as a key component of Wide Area Monitoring Protection and Control (WAMPAC) applications. In WAMPAC applications, PhCs will typically analyse synchronised measurements from multiple PMUs and/or PDCs (Phasor Data Concentrators) to produce either binary (on/off) control signals or continuous control signals (like MW power values).

To provide an adaptable base for control schemes, the PhC control platform provides an open IEC 61131-3 PLC (Programmable Logic Controller) program execution environment that can run diverse control application schemes consisting of interconnected application function blocks (AFBs) by using the wide area and local measurements. The modular nature of these AFBs and their implementation in a PLC environment helps develop, extend and optimise the WAMPAC. Figure 10 shows the PhasorController.

The different AFBs that have been developed to provide the functionality of the MCS are described in Chapter 10 (Project replication).

Figure 10: GE Renewable Energy's PhasorController used in the EFCC project

MCS testing and training
After the MCS algorithms and hardware were developed, they were tested and installed at various project partner locations for performance validation and commercial trials to be completed. GE provided training to tell partners about the implementation considerations and the system's functional behaviour.

Testing included factory and site acceptance tests, then the output of the MCS was monitored against system frequency events and its settings modified to allow the MCS to trigger a response from the commercial partner sites.

More technical details about the PhasorController are in Appendix C and the MCS testing regime in Appendix D.

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MCS performance validation

The universities of Manchester and Strathclyde were responsible for validating the function and performance of the MCS and demonstrating its effect under future lower inertia conditions. Research teams used simulation and physical hardware techniques.

Simulation analysis (University of Manchester)

A Hardware-in-the-Loop (HiL) testing approach was developed to prove the robustness of the MCS and understand how it would perform against a variety of power system scenarios. The approach used a high-fidelity network simulation model, in a Real Time Digital Simulator (RTDS). The HiL setup consisted of the RTDS model (using GPS time synchronisation) that was physically connected to the MCS controllers using an industry standard communication infrastructure. Figure 11 shows the laboratory setup with the RTDS.

Figure 11: RTDS racks in the lab at the University of Manchester

Simulated PMU devices were modelled in the RTDS, which allowed the MCS to receive measurements from the network model using IEC C37.118 data streams.

Using these measurements, the MCS calculated response and sent signals to service providers modelled within RTDS. Service providers were also modelled in RTDS, and their characteristics linked to LCs. Figure 12 shows how the MCS controllers, PMUs and service providers were linked together.

The RTDS simulation environment allows for more realistic interfacing with hardware, although the practical limits of computation need to be considered. Due to computational limitations, the University of Manchester built a reduced 26-bus RTDS model of the NETS, based on the 36-bus model provided by NGESO (Appendix B shows the 36-bus and 26-bus models). The performance of the reduced 26-bus model of the NETS was then validated against the 36-bus model to make sure that it correctly reflected the essential characteristics of the network.

The MCS was tested using a closed-loop method with the RTDS to consider the performance of the architecture (including computational delays of the control system). This closed-loop method meant:

- the MCS measured the simulated frequency, voltage and phase angles in the 26-bus model
- the MCS calculated the RoCoF and the required volume of response
- the output signals from the MCS were fed back to the simulated models of the service providers.

A series of tests were conducted (as listed in Table 7) using the 26-bus model, to represent different levels of low system inertia (82GVA.s and 50GVA.s). A range of scenarios were simulated to validate the performance of the MCS as follows:

- to demonstrate that it is more effective in containing frequency events compared to traditional response services
- to demonstrate that it can deliver the appropriate

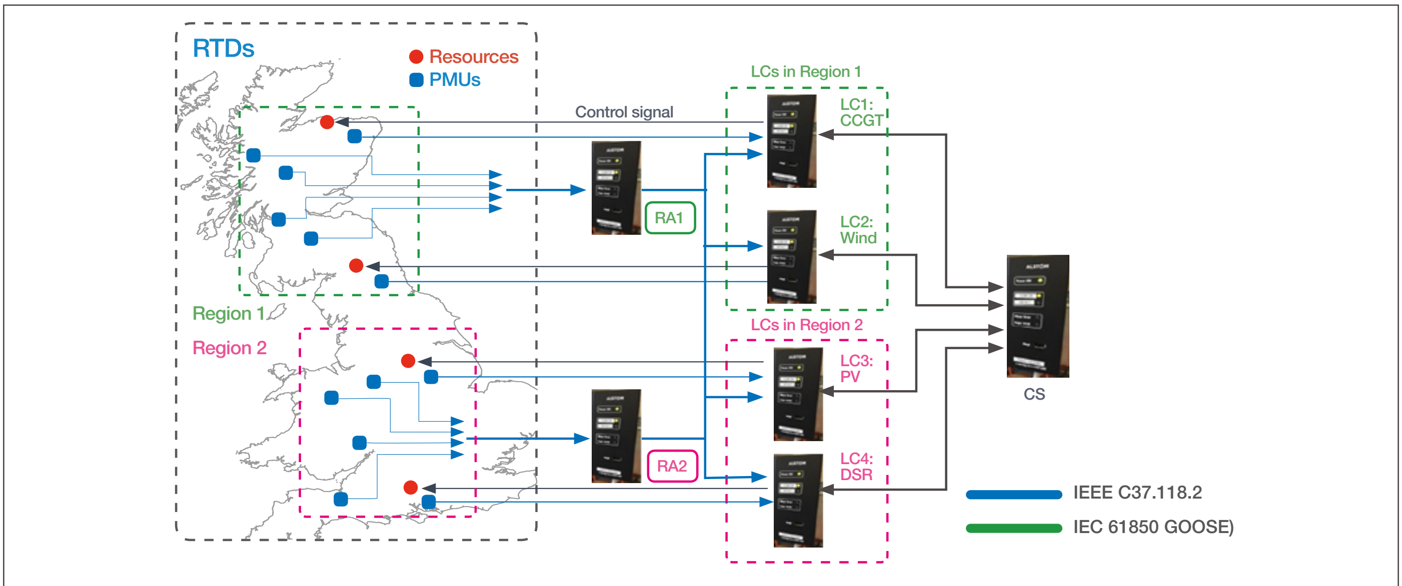

Figure 12: The test setup with the MCS controllers, PMUs and representative service providers

response in the appropriate region
- to show that it can detect system faults (and not operate)
- assess how different ramp rates, volume and location of service providers impacts performance.

The simulations completed using this RTDS setup were suitable for validating the performance of the MCS against different dynamic conditions on the network using complex load and generation models. However, the simulated PMU signals are not fully realistic compared to those in an actual network. In a live network environment harmonics, waveform distortions and system noise would affect the PMU's measurement accuracy, and would affect the decisions made by the controllers. The University of Strathclyde's analysis investigated the effects of live network conditions on the performance of the MCS.

Test case	Test aim
Test 1.1: MCS response for a 1000 MW load increment event in England and Wales with sufficient resource	Verify appropriate response delivered to one under-frequency event
Test 1.2: MCS response for a 1000 MW load increment event in England and Wales with finite resource	How the MCS responds to a disturbance with insufficient volume
Test 1.3: MCS response for a 1000 MW load increment event in Scotland with finite resource	Verify the ability to detect the event at disturbed region
Test 1.4: MCS response for a 1500 MW load increment event in England and Wales with sufficient resource	Verify the ability of the MCS to counter different events
Test 1.5: MCS response for a 1000 MW load disconnection event in England and Wales with finite resource	Verify appropriate response delivered to one over-frequency event
Test 2.1: MCS response for a 140ms single phase ground fault in England and Wales	Verify the MCS can detect the single phase-ground fault
Test 2.2: MCS response for a 140ms single phase ground fault in Scotland	Verify the MCS can detect the single phase-ground fault at different locations
Test 2.3: MCS response for a 140ms double phase ground fault in England and Wales	Verify the MCS can detect the double phase-ground fault
Test 2.4: MCS response for a 140ms three phase ground fault in England and Wales	Verify the MCS can detect the three phase-ground fault
Test 2.5: MCS response for a 140ms three phase ground fault in Scotland	Verify the MCS can detect the three phase-ground fault at different location
Test 3.1: MCS response for a load increase after 140ms short circuit fault in England and Wales	Verify the MCS can detect the fault and response to the frequency event after a fault in England and Wales
Test 3.2: MCS response for a load increase after 140ms short circuit fault in Scotland	Verify the MCS can detect the fault and response to the frequency event after a fault in Scotland
Test 3.3: MCS response for a generator tripping after 140ms short circuit fault in England and Wales	Verify the MCS can detect the fault and response to the generator tripping event after the fault
Test 3.4: MCS response for a line disconnection after 140ms short circuit fault in England and Wales	Verify the MCS can detect the fault and not influenced by line tripping after the fault
Test 4.1: Impact of PMU weights on system frequency by comparing inertia from RTDS	Investigate the impact of weighting of PMUs to the performance of the MCS
Test 4.2: Impact of minimum fault blocking time on event detection after a short circuit fault	Investigate the impact of minimum fault blocking time to the performance of the MCS
Test 4.3: Impact of amount of service provider response	Investigate the impact of amount of service provider response to the performance of the MCS
Test 4.4: Impact of ramp up rate of service provider response	Investigate the impact of ramp up rate of service provider response to the performance of the MCS

Table 7: List of RTDS simulation tests conducted by the University of Manchester

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Physical network analysis (University of Strathclyde)

The University of Strathclyde established a highly realistic testbed that coupled a NETS model in RTDS with an 11kV physical network using a Power-Hardware-in-the-Loop (P-HiL) configuration.

The testbed contains two main parts: a reduced NETS model simulated in RTDS and an 11kV physical network with load banks connected. The 11kV site is based at the Physical Network Demonstration Centre (PNDC) and can be operated in isolation to the electricity grid but features the key elements of a power system at a lower scale (up to 1MW). The site includes cable and overhead line network assets together with load banks to simulate demand with variable characteristics and a Motor-Generator (M-G) set that can operate at different levels of system inertia. Figure 13 shows a single line diagram of the 11kV network. Within the facility, physical plant and control systems can be connected to test data quality and the impact of communication delays. Network events can be physically tested, and real-time measurements fed to the simulated network within the RTDS and the MCS.

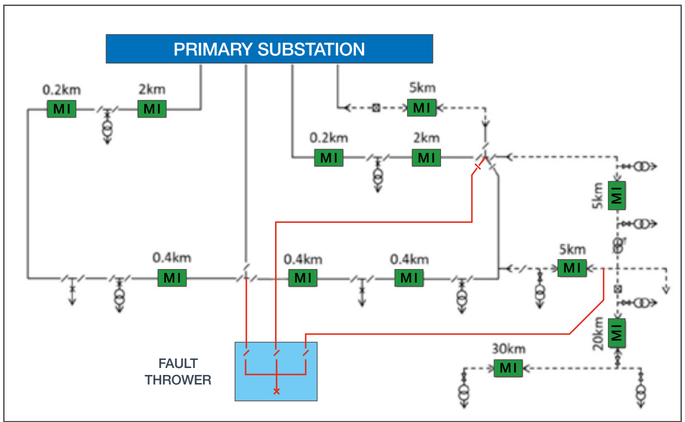

Figure 13: Single line diagram of the PNDC network

Interaction between the simulated 36-bus network model and the 11kV physical network is achieved by controlling the MW-scale of the Motor-Generator (M-G) set as a P-HiL interface. The M-G set can be modified to reflect a system inertia condition with the energy imbalance (caused by a frequency event) met by changing the load banks and/or M-G set in real time.

The 36-bus NETS model in RTDS is divided into three regions (as shown in Figure 14), where each region has two P-Class PMU simulation models streaming real-time synchrophasor data to the three RAs. The three RAs receive and process real-time measurements from the RTDS simulated PMUs and send data to the two LCs. One LC (i.e. LC1) controls an energy storage resource modelled in the RTDS and the other LC (i.e. LC2) controls a physical load bank acting as a demand side response. As well as the simulated PMUs linked to the RAs, each LC was assigned a PMU for local measurement, which was used if poor quality wide area monitoring signals were received. The PMU used by LC2 was physically installed at a bus in the 11kV network that is synchronised with a bus in the RTDS simulation, while LC1 used a simulated P-Class PMU in RTDS.

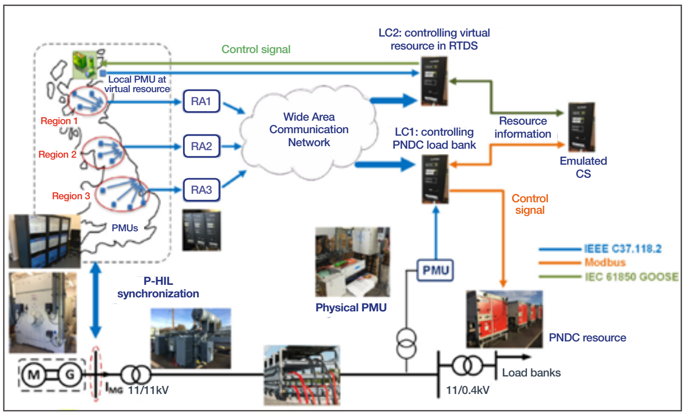

Figure 14: P-HiL testbed for testing the MCS wide area operational mode

Table 8 outlines the tests conducted on the MCS to evaluate its reliability and robustness under different network conditions. The tests assess the capability of the MCS for:

- different types of frequency disturbances (such as under- and over-frequency events)
- different sizes of frequency events (such as different amounts of power imbalance)
- events at different locations of the network
- different types of service provider and their locations.

The tests highlight the impact of the various system factors described above on the MCS, and can be categorised as follows:

- tests 1, 2 and 3: evaluating the impact of the locations of the frequency disturbances
- tests 1, 4 and 6: evaluating the impact of service provider capacity on overall frequency containment. Tests 3, 5 and 7 were defined for the same purpose, but the frequency disturbance was in a different region
- tests 1, 8 and 10: evaluating the impact of the service provider with different MW volumes of capacity. Tests 3, 9 and 11 were defined for the same purpose, but the frequency disturbance was in a different region
- tests 6 and 12: evaluating the impact of the size of the power. Tests 7 and 13 were defined for the same purpose, with the frequency disturbance in a different region
- tests 1, 14 and 15: evaluating the impact of the locations of the service providers.

Communication performance

The University of Strathclyde also evaluated the impact of communication performance of the MCS. This was achieved by emulating a wide range of degrading communication conditions and analysing how they impacted the operation of the MCS. Figure 15 shows the communication test setup. The MCS communications architecture involves a regional network between the PMUs and the RAs, and a wide area network between the RAs

Tests	Event size	Event location	LC1 location	LC1 resource	LC2 location	LC2 resource
1	1 GW	R3	R1	300 MW	R3	300 MW
2	1 GW	R2	R1	300 MW	R3	300 MW
3	1 GW	R1	R1	300 MW	R3	300 MW
4	1 GW	R3	R1	600 MW	R3	600 MW
5	1 GW	R1	R1	600 MW	R3	600 MW
6	1 GW	R3	R1	1 GW	R3	1 GW
7	1 GW	R1	R1	1 GW	R3	1 GW
8	1 GW	R3	R1	300 MW	R3	1 GW
9	1 GW	R1	R1	300 MW	R3	1 GW
10	1 GW	R3	R1	1 GW	R3	300 MW
11	1 GW	R1	R1	1 GW	R3	300 MW
12	1.32 GW	R3	R1	1 GW	R3	1 GW
13	1.32 GW	R1	R1	1 GW	R3	1 GW
14	1 GW	R1	R2	300 MW	R3	300 MW
15	1 GW	R1	R3	300 MW	R3	300 MW

Table 8: List of tests conducted for evaluating the MCS robustness
Location Key: R1 represents Scotland, R2 represents northern England, R3 represents southern England

and the LCs. Both networks were simulated for test purposes, with different communication performance conditions (such as different levels of latency, jitter or loss of packets rate) evaluated to understand how they affected the MCS's performance.

The MCS was tested in both wide area and local modes of operation. Further detail on the test procedure is available on the project website.

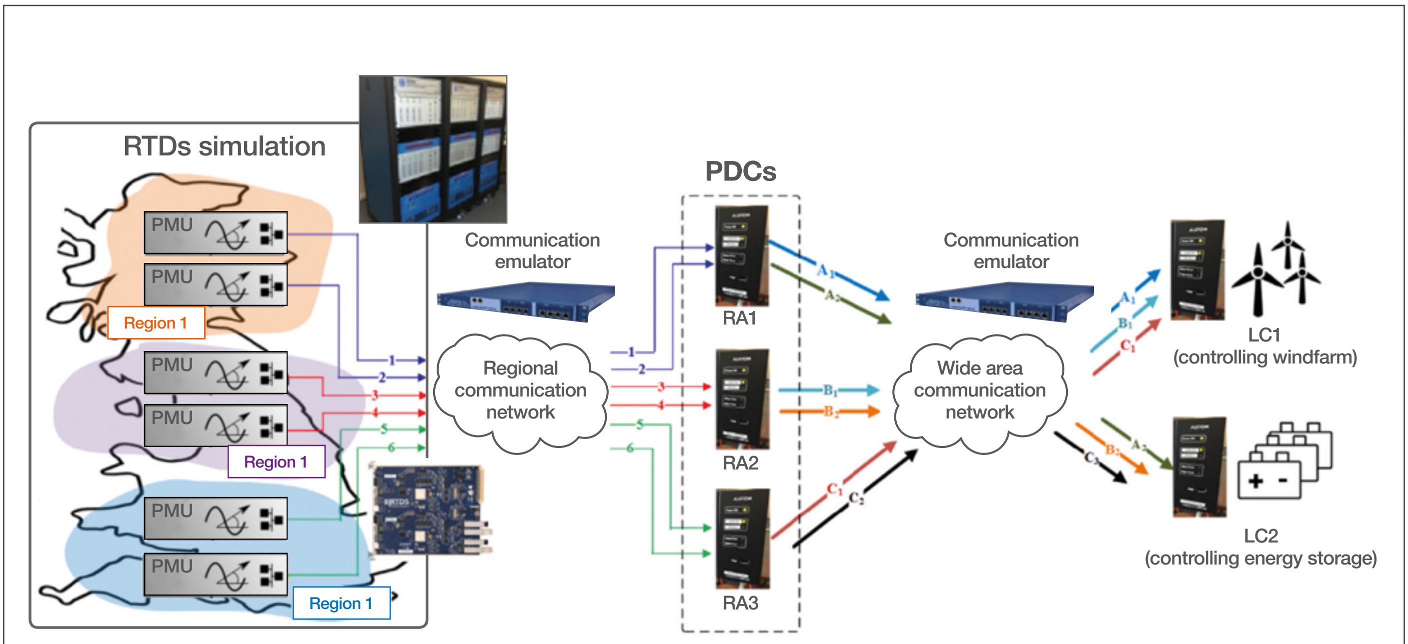

Figure 15: Test setup for evaluating the communication performance impact on the operation of the MCS

Technology assessment for fast frequency response with the MCS

An assessment of the capability of different technology types to provide fast frequency response was completed. How certain technology types would interface with the MCS was also evaluated. This included the impact of the service provider location, communication protocols, and individual site conditions on the overall response delivered.

The testing regime for each of the technology types evaluated on the project is described in this chapter.

Demand side response

Flexitricity explored and demonstrated ways in which demand side response (DSR) could support a low inertia electricity system by responding very rapidly to sudden changes in frequency. Flexitricity developed three new services for this project and tested them on real commercial and industrial electricity loads and small embedded generators. The services tested were:

- **Static RoCoF** – switching off electrical loads when the RoCoF breaches a specified limit
  - a chemical manufacturer with a 6MW compressor unit (PMU and LC installed)
- **Spinning Inertia** – operating synchronous embedded generators (CHP engines) at part and full load and monitoring their natural response to variations in system frequency
  - a large greenhouse with two CHP engines (PMU only installed)
  - a district heating plant with two CHP engines (data logger installed)
- **Dynamic RoCoF** – continuous adjustments to flexible loads in response to a locally measured RoCoF value. All the following sites installed Allen Bradley micro controllers:
  - a cold store facility with compressors
  - a wastewater treatment work with blowers and pumps
  - a wastewater pumping station.

These new services were operated using generation and electrical load assets on sites belonging to Flexitricity's commercial partners.

Working with these partners, Flexitricity installed frequency and RoCoF monitoring equipment on each site and integrated them into the site equipment's control systems. Outstations and communication channels were installed to allow Flexitricity to monitor the sites and to arm and disarm the RoCoF response as needed.

At some sites, the frequency and RoCoF monitoring equipment was provided by project partner GE Renewable Energy, while on others it was provided by Flexitricity.

Further information on the test setup at each site is described in Chapter 10 (Project replication).

Site assessment

A central element of the assessment was to determine the operational parameters needed for the monitoring and control equipment to work, and to create the technical functionality to support its operation. In most cases, operational parameters were adjusted following a period of observation after equipment was installed on site.

Demonstrating the effectiveness of the different services required observing the site's assets' response to system frequency. Each site's performance during instances of rapidly changing frequency and high RoCoF was observed, as these occasions are indicative of more volatile frequency behaviour that's associated with low inertia systems. Field trials took place on all sites over several months during 2017 and 2018. The sites were monitored remotely from Flexitricity's control centre and data was logged during all periods of operation.

Large-scale generation

Centrica/EPH demonstrated faster initiated frequency response at their South Humber Bank Combined Cycle Gas Turbine (CCGT) by implementing five steps:

- create a simulation of the Gas Turbine (GT) controllers in a simulation package and apply the conceptual design
- use of an actual Distributed Control System (DCS) module in a test rack, to replicate the actual GT controllers, implement the new concept and replay real system events to test what the GT controllers would do
- install the design concept onto the live GT controller, conduct standard Grid Code frequency response tests and monitor how the GT responded
- compare the modified GT controller with another unmodified GT controller on the same network connection
- use a PMU and LC to remotely dispatch a GT load change. This was not completed because the CCGT plant was unavailable.

Centrica/EPH explored the adaptation of an existing conventional droop controlled frequency response to achieve faster frequency response in response to either a frequency change or a rate of frequency change as initiated by the LC. The aim was to design a solution that did not drive instability in the machines' behaviour, and which provided a predictable and sustainable frequency response.

Figure 16 shows the setup for the trial.

PV power plant

BELECTRIC provided RoCoF based response initiated by the LC with a large-scale converter based at the 3.74MW Rainbow solar photovoltaic (PV) farm. A 1MW/1MWh battery energy storage system was also considered at this site, both operating separately, and with both combined working as a hybrid power plant. The battery energy storage system was leased for the trials. This was funded separately via the Network Innovation Allowance (NIA). This is discussed further in the 'Required modifications to the planned approach' chapter of this report.

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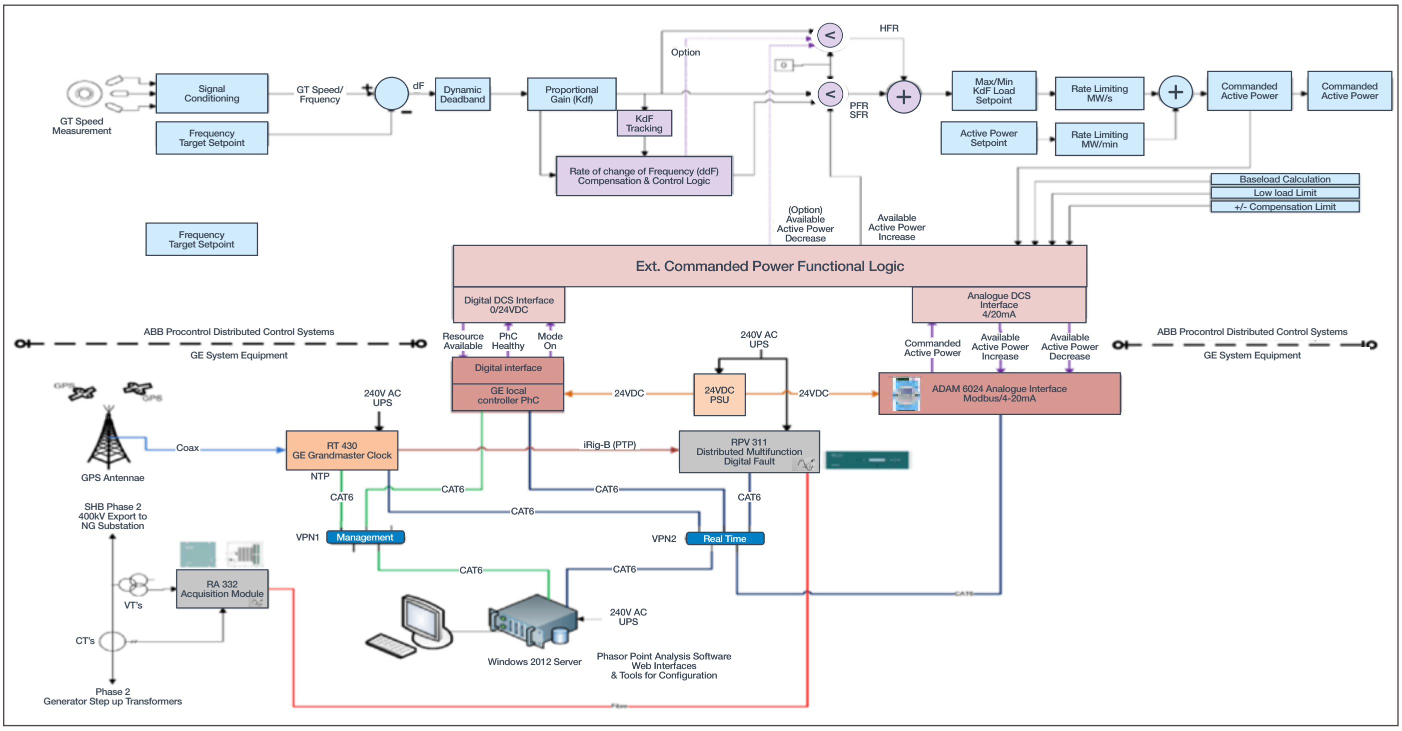

Figure 16: South Humber power station schematic showing GE Renewable Energy monitoring installation

The trials for the EFCC and the battery storage NIA projects were run in parallel to efficiently integrate the learning outcomes across both projects. This section of the report outlines the solar PV forecasting techniques and the integration of the hybrid power plant with the LC. The existing control systems of the solar PV farm were unchanged and the LC was operated in local mode (i.e. the controller was configured to receive only locally available frequency measurements).

Several series of tests were conducted in open loop and closed loop modes. In open loop mode, functional tests of the site control system and communications setup were completed without control signals being sent to the solar plant inverters. In closed loop mode, the tests included control signals to the inverters to evaluate the performance of the solar PV farm with the LC using simulated and real frequency events. Figure 17 shows the schematic of the solar PV and battery unit connections.

Solar PV forecast and power plant model

The LC needs to know the availability of the connected service providers to assess their individual frequency responses. So, for the integration of the solar PV system with the LC, a forecast system was developed. A cloud draft camera was used, the results of which were used as inputs for a sophisticated solar PV power plant model. This meant the solar PV power plant output could be forecast for a period between one minute and one hour. This approach achieved an accuracy target of over 95% for the 15 minute forecasts. A statistical forecast method was also used to help optimise the forecasts. The forecasting model had several variables that can be optimised to either maximise the power output of the solar plant to provide a longer forecasting time to evaluate, or to minimise the error margin of the response.

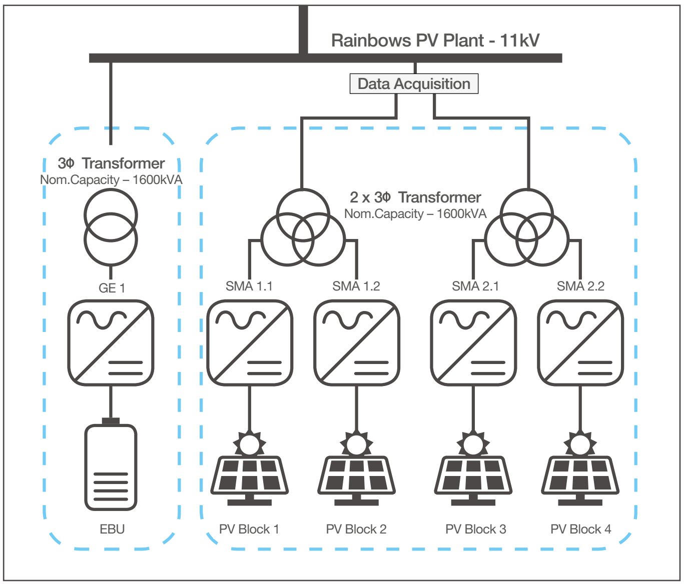

Figure 17: Schematic of the solar PV+Storage Hybrid System with 3.7MW Rainbows solar PV farm and 1MW/1MWh Energy Buffer Unit (EBU) 1000 in Willersey, UK

The solar PV power plant MATLAB model was used to represent the Rainbows solar PV farm, the behaviour of its components and its power output capability. This model enabled the power plant control system to curtail the output to a known percentage below the possible maximum output power. With this curtailment, the PV power plant can give a positive and negative frequency response. In combination with the forecasting system, availability for both positive and negative power over a timeframe of one minute to 60 minutes could be given to the LC.

Solar PV and battery storage hybrid system

The solar PV power plant is connected to the battery unit via a fibre optic cable to form the hybrid plant. Both technologies were coupled to the same grid connection point and controlled by the BELECTRIC Hybrid Control system. A PMU was installed on site and integrated with the LC. If a frequency event aligned with the RoCoF threshold setting in the LC, a control signal was sent to the BELECTRIC Hybrid Control system requesting a specific amount of power from the plant.

The BELECTRIC Hybrid Control was adapted to achieve the optimal reaction of the solar PV and battery storage plants. It can control and regulate the plants, including various measuring and control instruments, both individually and in combination. This means that substantially faster response reaction times from the hybrid system can be achieved. Depending on the test regime and resource availability, either the solar PV plant, battery unit, or both, would respond to the LC request.

Site communications

The communication capability of the solar PV power plant was improved in terms of the data volumes, data traffic and data speed between several control components on site. This was done by retrofitting and improving communication units, eliminating redundant processes in the control cycles and using faster communication protocols between critical control components. Figure 18 shows the communication protocols used at the site.

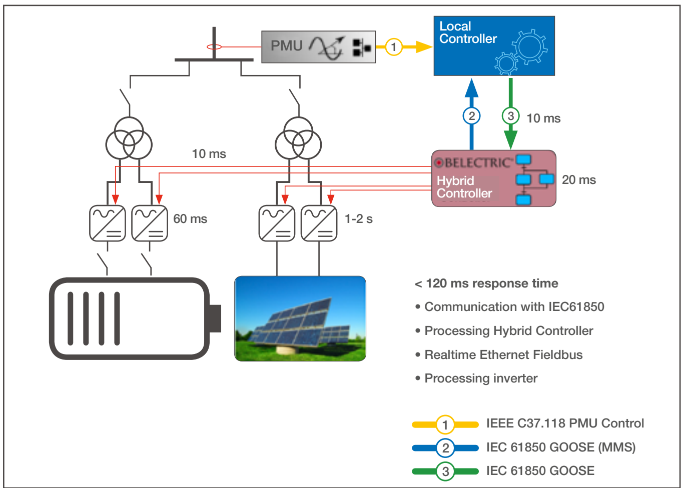

Figure 18: Communication overview and communication protocols used between the different systems control and components

Wind

Ørsted and Siemens Gamesa Renewable Energy (SGRE) aimed to test if wind power plants can deliver fast-acting frequency response when there is no active power deload and against faster forms of traditional response. Normally, wind power operates at or near 100% of the power available, so the ability to deliver low frequency response is limited. Therefore, the scope of the trials also included simulations and analysis to quantify the benefit of using an alternative frequency response technique that is not currently used by NGESO.

Burbo Bank wind farm

Current frequency support modes with enhanced settings were tested at the Burbo Bank wind farm. This involved simulation studies and frequency injection tests. Frequency Sensitive Mode (FSM) was tested on the Burbo Bank wind power plant but with more response for droop settings (up to 1%) in the power plant controller. Table 9 shows the full list of tests carried out.

Wind turbine inertial response

SGRE conducted tests and simulations on the capability of its SWT-7.0-154 (7MW) wind turbines to deliver inertial response (IR). IR from wind turbines can contribute to frequency response without the need to create headroom before providing MW response (for low frequency events) by extracting energy from the turbine rotor. IR is a known technique where power is rapidly extracted from the turbine. However, this leads to an energy deficit within the turbine that needs to be recovered. IR testing was carried out on a single turbine at SGRE's national test centre in Oesterild, Denmark, and additional simulations were performed using a high-fidelity simulation programme. The simulations considered two IR injection periods (10s and 5s with slow ramping down) and produced a set of IR response profiles that related the amount of response available to the output of the turbine before the response was activated. The IR injection periods were chosen for comparison analysis and are described in the section below. As IR is primarily based on the settings within the turbine control system, other injection periods can be defined.

To understand the likelihood of wind farms delivering a specific amount of IR response at any time, Ørsted combined the SGRE profiles with historical wind speed, direction and power generation data from their portfolio of wind farms in GB. Probabilistic analysis was carried out and an active power versus likelihood chart was generated to indicate the amount of IR that could be available on the network.

Analysis of wind inertial response on the electricity network

The University of Strathclyde applied the SGRE IR profiles to the 36-bus DIgSILENT PowerFactory model of the NETS. The model represented a transmission system inertia of 82GVAs, which is significantly lower than what is apparent today. Analysis was completed to assess the impact of the IR in terms of the amount of response available, when the response is activated after a frequency event, the location on the NETS of wind farms with IR, and the total capacity of windfarms with IR on the network. The analysis considered the impact of the energy deficit produced after the IR response has been delivered to evaluate its impact on frequency containment.

Specifically, two IR duration profiles where chosen to investigate the range of the system impacts in using IR response. The profiles were also categorised as conservative and mean. The conservative profile represents the inertial response from the 90% percentile of the number of simulations taken and the mean profile

Test number	Mode	Droop (%)	Deadband (Hz)	Frequency injection (Hz)	Description of the test
1	FSM	3.3333	0.015	-	Frequency Sensitive Mode (FSM) of operation with prior power reduction to provide under frequency response
2	FSM	3.3333	0.015	-	Standard FSM; as the frequency exceeds the dead band, the wind farm responds with the appropriate magnitude of power
3	FSM	1.0000	0.015	-	Faster acting response based on a smaller droop and narrow dead band.
4	FSM	20.0000	0.015	-	To show the wind farm operation with high droop setting.
5	FSM	3.3333	0.100	-	To validate the behavior with FSM enabled, but not triggered. The frequency does not exceed the dead band so response is not initiated
6	FSM	3.3333	0.200	-	
			0.300		
			0.400		
7	FSM	3.3333	0.015	49.50	To show the response profile for a large under frequency deviation, with an artificial frequency, measurement is injected
8	FSM	3.3333	0.015	50.50	As above, though for an over frequency deviation
9	N/A	N/A	N/A	0MW	Curtailment from full production to 0MW with a large enough droop to be limited by the turbine mechanical ramp rate (20% per second)

Table 9: Burbo Bank wind farm tests

represents the average (50%) of the simulation data.

These response profiles are described in Figures 19 and 20 respectively that show:
- 10s IR duration for SGRE D7 wind farm turbine with 20%-100% of rated power
- 5s IR duration with slow ramping-down (SR) after the inertial response for SGRE D7 wind farm turbine with 20%-100% of rated power.

A static generator was modelled in each of the 36 zones of the model to characterise a SGRE wind farm whose MW output was configured to exactly follow the IR profile provided.

The original IR profiles ramp up at 10s with nearly zero output before that. During the system study, it was found that the simulation will typically reach to steady state before 5s, so to speed up the simulation process and reduce computational efforts, the profiles were adjusted so that the response was trigged at around 5s. The exact time of triggering the IR depends on the desired activation time compared with the loss-of-infeed event, e.g. ramping up at 5.5s if IR activation delay is 500ms after the event at 5s.

Impact assessment of the MCS on operational systems

NGESO carried out an assessment of how the MCS would affect the communications network and the operational business systems used to balance the NETS. The approach taken included:

- understanding of the MCS that was developed by GE Renewable Energy
- understanding of the physical system architecture to understand the communications protocols of the MCS and the software interface that allows the settings to be altered
- evaluating the MCS from robustness, resilience and security perspectives. The security aspect considered potential redundancy as well as the cyber security of the MCS PhasorControllers
- identifying the business and technical impacts on NGESO processes (e.g. modelling, forecasting) and systems (registration and balancing systems), if the MCS is incorporated into business as usual activities
- identifying further work and opportunities for the MCS to be incorporated into business as usual.

Understanding the MCS, process mapping and communications bandwidth

The first stage of the work involved a series of workshops with the University of Manchester, the University of Strathclyde and GE Renewable Energy to map out the functions of the MCS, defining each component of the scheme and the data exchanges to other components. During these sessions, it was possible to understand the initial operational conclusions from the academic testing and explore the principles of the MCS. This was crucial to be able to identify where, within NGESO's systems and processes, the data for the settings of the MCS could be obtained, and how much data traffic would need to flow across the communications network.

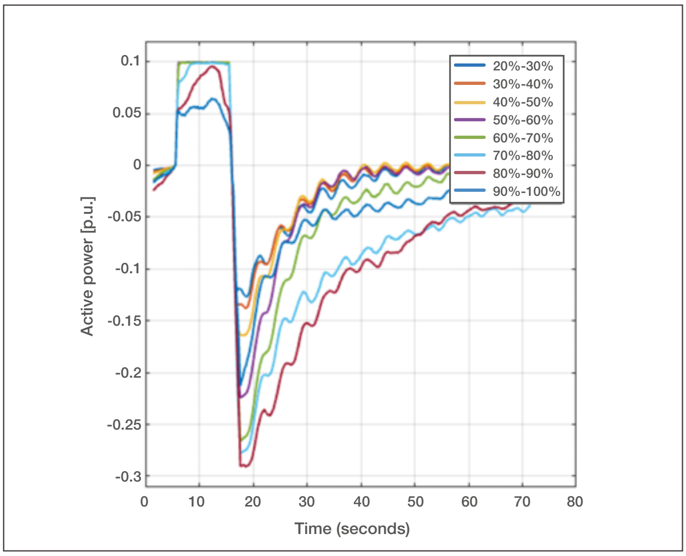

Figure 19a: 10s duration park level IR for D7 wind farm turbine with 20% to 100% of rated power; conservative profile

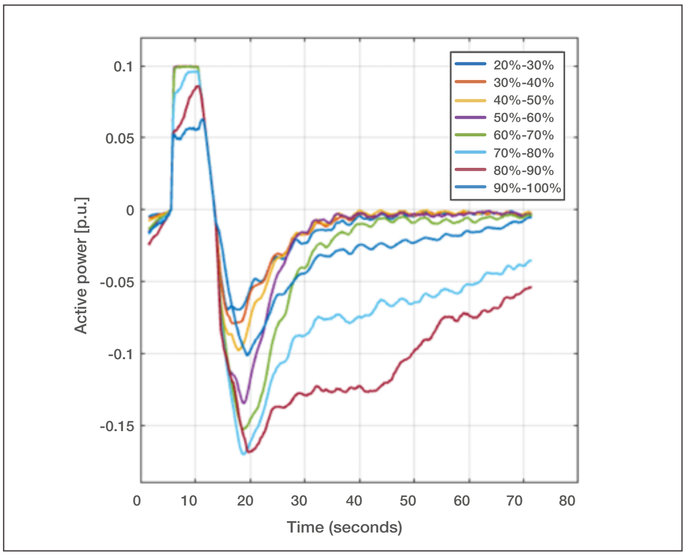

Figure 20a: 5s duration park level IR for D7 wind farm turbine with 20% to 100% of rated power; conservative profile

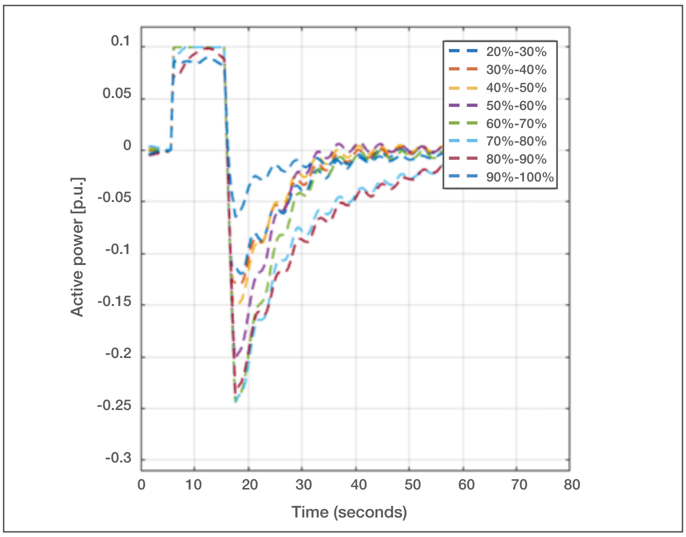

Figure 19b: 10s duration park level IR for D7 wind farm turbine with 20% to 100% of rated power; mean profile

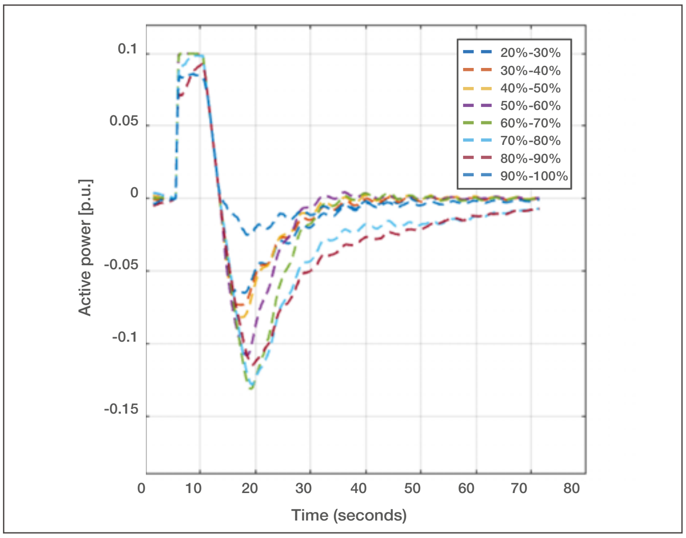

Figure 20b: 5s duration park level IR for D7 wind farm turbine with 20% to 100% of rated power; mean profile

An impact assessment was done to identify the interactions with frequency response services and systems, operational planning processes, NETS modelling and energy forecasting. A main element to this work was to understand how the fast frequency response delivered using the MCS would be dispatched. As the NGESO is reviewing energy balancing dispatch systems, this analysis was completed based on existing systems.

Cyber security assessment of the MCS

For the MCS to be installed on National Grid's communications network, it was tested to determine whether it would be possible for someone with malicious intent to hack into the system and disrupt its operation. The test schedule also examined how access is granted to the relevant software and algorithms.

Value of coordinated fast frequency control

The original project objective was to develop and implement a new EFCC (RoCoF based) frequency response balancing service. However, as the project progressed, it become apparent that this activity could not proceed as envisaged based on industry engagement regarding the future of balancing services which signalled the number of frequency response services should be rationalised. As a result, the focus of this work package was to consider the technical capability of service providers and assess the value to consumers of a faster (0.5 second) response coordinated by the MCS.

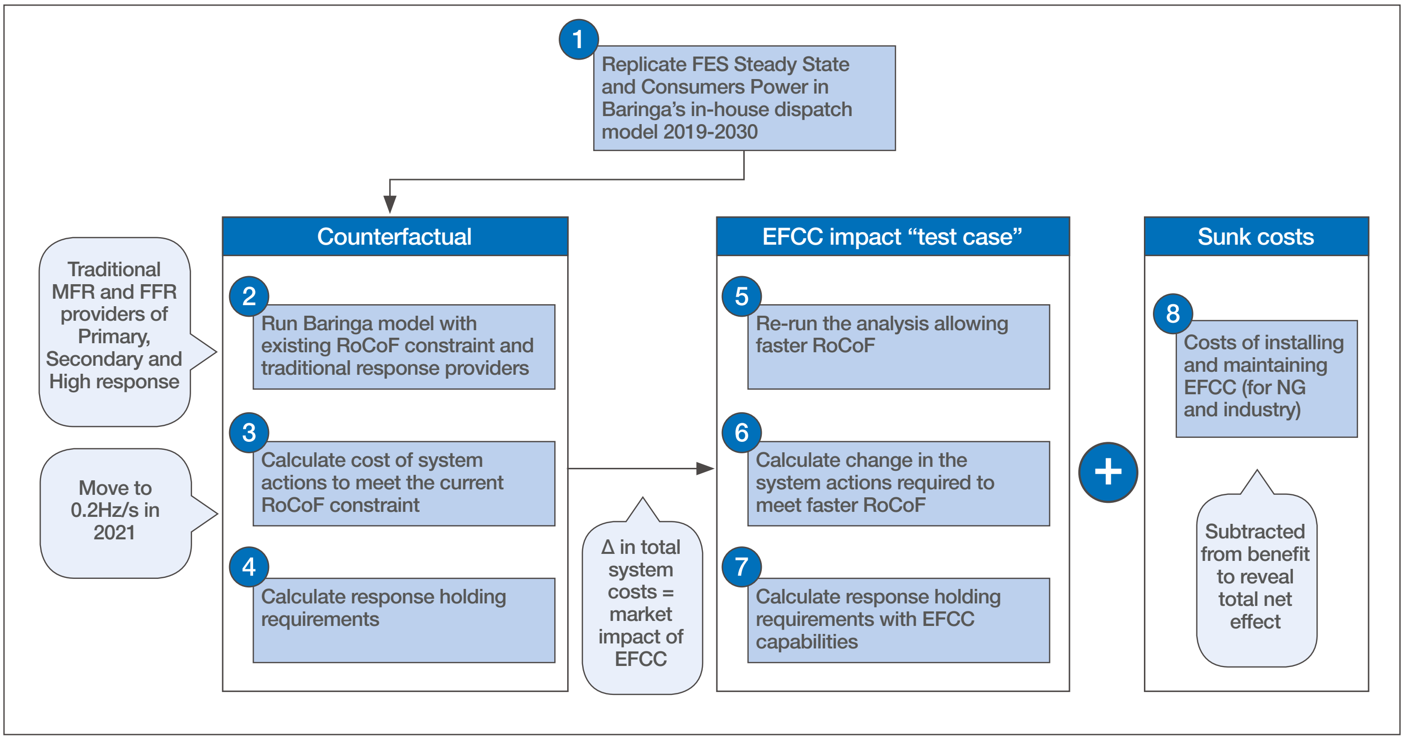

Figure 21: CBA approach

Investigate commercial opportunities
The assessment of the commercial opportunities for an EFCC (RoCoF based) fast frequency response service depends on the commercial field trials and would be a key input to the cost benefit analysis.

The trials would assess and demonstrate what fast frequency response could be achieved from different technologies to help operate the electricity transmission system, both now and in the future. The trials confirmed that a range of different technologies could provide faster frequency response. Where technical and operational issues were identified in the speed of response, energy recovery or setup requirements, further assessments and solutions were put forward to address the issues raised.

Valuation of EFCC as a balancing service
A revised cost benefit analysis (CBA), completed by Baringa Partners, was completed using the results from the commercial trials and considered recent changes to the energy landscape. The results of the CBA confirm the potential benefit to the industry and consumers of implementing the solution developed by the project.

CBA approach
Baringa developed a model to calculate the economic benefits of dispatching faster frequency response with the MCS as shown in Figure 21.

The model identifies the distribution of potential benefits of re-dispatching generation (including interconnectors), captures any changes to the curtailment of this generation to manage the transmission system, and includes changes to the carbon intensity of the generation mix in GB. The 2017 Steady State and Consumer Power Future Energy Scenarios[1] were selected for building a model of the GB market with the response assumptions coming from the commercial field trials results.

The CBA considers the benefits of 0.5 second frequency response dispatched by the MCS (EFCC scenario) against the existing services (Primary, Secondary and Enhanced Frequency Response (EFR) and High) for managing system frequency (counterfactual scenario). The difference between the two approaches determines the potential benefit of the EFCC scenario.

Modelling assumptions
The CBA was based on the following modelling assumptions.

RoCoF limits
The MCS provides a mechanism to deliver faster frequency response to enable the system to operate at a faster RoCoF in lower inertia situations. The RoCoF limits used in the modelling range from 0.125Hz/s to 1Hz/s over the period out to 2030 for the two different scenarios.

In the counterfactual scenario, the RoCoF limit is 0.125Hz/s, which relates to the existing settings for RoCoF relays on embedded generation i.e. embedded generation connected to the Distributed Network Operator (DNO) network will be disconnected if the RoCoF reaches 0.125Hz/s. This limit increases to 0.3Hz/s on the basis that the RoCoF relays will

[1] http://fes.nationalgrid.com/fes-document/fes-2017/

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be changed to allow the rate to be increased. In the EFCC scenario, the RoCoF limit is the same as in the counterfactual case in the early years, increasing to 1Hz/s in later years. This limit has been included as the system validation studies have shown that the MCS can allow the system to be operable up to this level.

Response modelling
The response modelling sets the demand for each response service using regression analysis for the relationship between demand, system inertia, generation or demand loss and static response. For the counterfactual scenario, the regression analysis was performed on historical response holding data to find the relationship between Primary, Secondary and EFR response. The EFCC scenario used analysis completed by the University of Strathclyde to determine the MW volumes of (Primary, Secondary, EFR and EFCC (0.5)) response required for a range of system inertias, largest loss, and demand levels for the regression analysis.

Economic decisions are taken within the model such that if it is more economical to sustain an EFCC type response longer than 0.5s, then the model will choose to hold these resources over other service options. The model calculates the response holding provisions from each of the technologies included in the EFCC scenario analysis, considering:
- the economic market dispatch (where applicable)
- availability of response in each hour (accounting for wind speed, solar irradiation profiles, system inertia constraints, outages).

Low and high frequency response is accounted for so that in the low response service, the model will either use available headroom to count towards response or deload generation where required to ensure response holding requirements were met each half-hour. The opposite is true for high response.

Technology roll-out assumptions
The technology roll-out assumptions, outlined in Appendix E, summarise the volume of capacity expected to provide EFR, Primary, Secondary, High and EFCC type response across the CBA period (2019 – 2030).

Monitoring and control system roll-out assumptions
The CBA also considers the cost of implementing the MCS. This expenditure was offset against the costs/savings associated with using a faster frequency response service with the MCS. The costs were based on:

i) Number of MCS component parts
The roll-out costs for full MCS implementation was based on six Regional Aggregators (RA) being operational, plus additional units available to cater for faults or breakdowns to bring the total to 18. Similarly, triple redundancy is applied to the Central Supervisor. It is assumed that each RA will have a minimum of four PMUs connected to it, and their installation costs have been accounted for in the cost assumptions.

ii. Number of service providers
The number of providers that could deliver response using the MCS remains uncertain. Three case studies have been developed to show the potential difference in approach and associated impact on costs.
- Service providers – all transmission connected
  - all 0.5s response is provided by transmission connected providers only
  - costs are based on the minimum number of providers needed to fulfil the response volume requirement
  - existing CNI (Critical National Infrastructure) communications is used.
- Service providers – transmission and distribution connections
  - 50% of the 0.5s response requirement is delivered by transmission providers, and 50% from distribution providers
  - distribution connections are based on 5MW capacity
  - communications between the MCS and the distribution connections is based on an internet connection to reflect a dispersed highly embedded situation.
- Service providers – transmission lead connections
  - 80% of the 0.5s response requirement is delivered by transmission providers, and 20% from distribution providers
  - response from distribution connections is provided by larger DNO providers at 20MW capacity
  - communications between the MCS and the distribution connections is based a dedicated DSL link to reflect where providers are relatively close to the GSP.

The roll-out costs also consider a possible phased implementation approach for the MCS. This is described further in Chapter 4 (Outcomes of the project).

Developing a commercial balancing service

A key project objective was to develop and implement a new EFCC (RoCoF based) frequency response balancing service. As the project progressed, it become apparent that this activity could not proceed as originally envisaged and it was decided that the work should be placed outside the scope of the project. This decision was based on the outcomes of the industry consultation on the future of balancing services. This consultation signalled that the number of frequency response balancing service products would be rationalised and new frequency response services developed with industry consultation.

Instead, the EFCC project team has shared the commercial trial test results with the review of balancing services to help develop the new frequency response products. The development of new frequency response products as outlined in '*Future of Frequency Response – Industry Update*[2]' document, doesn't mean the MCS developed by the project can't be used; its control system functions can be modified to incorporate the technical requirements of the new services. However, as the new frequency service products are still being developed, they have not formed part of the CBA analysis.

[2] https://www.nationalgrideso.com/document/138861/download

Outcomes of the project

System need for coordinated fast frequency control

The analysis focused on modelling alternative wide area frequency response control methods, as well as illustrating the benefit these approaches have in increasing the maximum generation loss which the National Electricity Transmission System can operate to. In addition, the project explored what approach could be taken for system frequency containment in the event response faster than 500ms was needed.

Key findings

- Three different control methods (real-time targeted control, real-time distributed control and system targeted control) were analysed to determine the benefit of wide area control systems (WACS).
- The analysis has confirmed that for lower levels of system inertia, all three wide area control methods can contain and restore system frequency. The control methods allow the largest loss on the network to be increased from 550MW to 800MW which could allow more renewable generation to be accommodated.
- Up to a rate of change of frequency (RoCoF) of 0.6Hz/s, if there was sufficiently fast frequency response available that is evenly distributed across the network, a real-time targeted wide area control method was not needed.
- The system state targeted control method can operate up to RoCoF levels of 0.6Hz/s. This approach requires less measurement infrastructure compared to the monitoring and control system (MCS) approach, and could form the basis for an initial phase of a wide area control implementation strategy.

Wide area control methods

Three wide area control methods were developed and modelled in DIgSILENT PowerFactory:

- real-time targeted control – which approximates the operation and performance of a wide area frequency control system such as the MCS developed by GE Renewable Energy
- real-time distributed control – where resources are deployed evenly across those available irrespective of the location of the event
- system state targeted control – where the picture of inertia distribution before the event is used to ensure a degree of co-ordination in the deployment of resources within a zone based on the system frequency and RoCoF during the event.

For each of the control methods, the frequency response was made proportional to the event size by using frequency and RoCoF to define the extent of the required response, in a similar way to the MCS developed by GE Renewable Energy. These control methods also provide a smaller volume of rapid response compared to a larger volume of slower acting, thermal generation.

The real-time targeted model more closely replicated the functionality of the MCS, against which the other control methods were evaluated.

Effectiveness on frequency containment

Each control method was analysed to evaluate its effectiveness at containing system frequency. The system conditions were also identified as to when the control methods would not be able to contain frequency above 49.5Hz.

System frequency events were simulated in the south west and north west of the NETS. Tables 10 to 12 show the corresponding future energy scenarios for years 2020/21 and 2025/26 and the largest generation loss that can be managed on the network. The respective system inertia is tabulated in Table 12. From the analysis conducted, all the control methods recover the frequency more effectively for larger losses than is possible without any fast, coordinated control.

Any of the three control methods enable an increase in the maximum loss which the NETS can operate to. The increase in largest loss is approximately 900MW in 2020/21 and 400MW in 2025/26.

Zone of frequency event	Largest loss giving a frequency nadir of 49.5 Hz	With any control methods	Increase in largest loss with any control method
South west	710MW	1560MW	850MW
North west	725MW	1685MW	960MW

Table 10: Largest system loss for scenario year 2020/21

Zone of frequency event	Frequency Nadir 49.5 Hz	With any control methods	Increase in largest loss with any control method
South west	530MW	925MW	395
North west	555MW	1035MW	480

Table 11: Largest system loss for scenario year 2025/26

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Scenario year	Base Power S (MVA)	Base Power times inertia S*H (MVAs)
2020/21	27349.03	83575.14
2025/26	27259.98	48601.75

Table 12: System Inertia

As can be seen from Figure 22, the real-time targeted method has the best frequency nadir as it uses the zonal frequency data, but all approaches deliver beneficial results. The real-time targeted method allows the size of the disturbance to be calculated and the required frequency response triggered within the zone. Both system state targeted and real-time distributed control methods result in similar frequency behaviour.

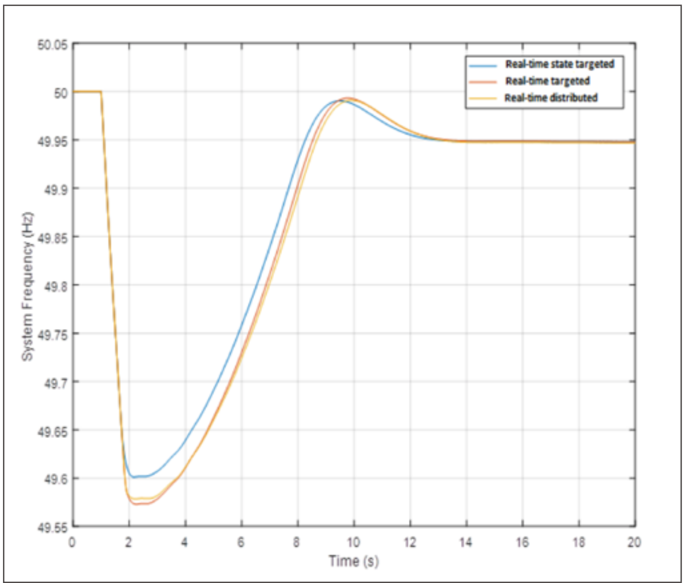

Figure 22: Comparison of the three control methods for 1560 MW generation loss in the south west zone in 2020/21

Impact of measurement time on frequency response

All the control methods measure the system frequency to determine if a response is needed. Each system frequency measurement (sample) takes a finite amount of time to complete. If numerous samples are taken, additional time will be required during which frequency will continue to move. It is therefore important to get the balance right between a long sampling period and a corresponding delay in deploying response. If the sample time is too short, this will lead to inaccurate measurements for the response deployment (see Figure 23).

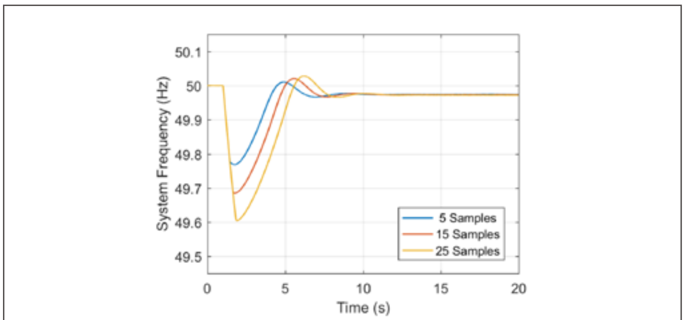

Figure 23: Comparison of system frequency containment with different samples for RoCoF calculation

Impact of RoCoF

When the RoCoF threshold reaches 0.6Hz/s, the system state targeted control method does not respond fast enough, potentially leading to frequency collapse. This is because the system state targeted method takes a sample of the system inertia before a frequency event which is now materially different from the sample taken during the event. At this stage, a real-time wide area control method is needed which will provide a targeted response to system frequency events.

Impact of resource availability

A worst case scenario of high response availability in Scotland versus zero response availability in England for a system frequency event in south west England was assessed. The results indicated in Figure 24 show that the real-time targeted control method would drive a short-term deviation in system frequency below 49.5Hz but above 49.2Hz. This demonstrates that the method can efficiently contain system frequency within statutory limits, however it would require significant power flows from Scotland to England. This highlights that the distribution of response across the network needs to be considered to avoid causing power flow constraints on the NETS.

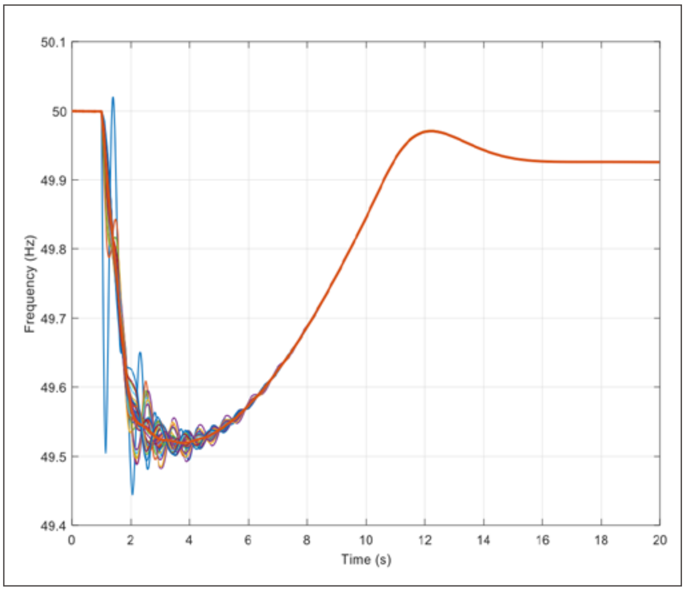

Figure 24: Frequency following loss of generation in zone 1 (SW England) of 1560MW (brown system frequency; light blue: zonal frequency of SW England) for scenario year 2020/2021 with unbalanced resource allocation

Wide area control method summary

The three control methods developed have enabled representative control systems to be modelled. These algorithms were designed with a flexible user interface allowing settings, like those deployed in the MCS developed by GE Renewable Energy, to be implemented and a comparison made between the different control methods.

The models were used to consider the future operation of the NETS with and without fast frequency control methods and showed the benefit of fast, coordinated frequency response for lower system inertia levels. The system state targeted method does not rely on real-time communication during a system frequency event, and can be an initial phase for wide area control system implementation.

Linear Quadratic Gaussian Control (LQGC)

If frequency containment faster than 500ms becomes necessary, alternative options beyond the control methods described, such as Linear Quadratic Gaussian Control (LQGC), would be needed. The project explored a theoretical approach using LQGC as an alternative method of faster optimised response deployment. A Linear Quadratic Gaussian optimisation technique is used to create a linear model of the electricity network which can be used to identify the most efficient response to a range of frequency events. During a frequency event this approach would deploy response in real time and adjust it as needed.

An advantage of LQGC is that it can trigger a response in real time based on frequency, voltage and voltage angle information, without the need to sample RoCoF. However, a disadvantage is that it has a limited ability to optimise different response characteristics as it does not calculate the amount of response needed.

This approach requires further analysis into its application for control of the NETS when system conditions require frequency containment faster than 500ms. A potential academic study outlining the theory of LQGC is detailed in '*LQG Supervisory Control Scheme for EFCC*'.

Monitoring and control system (MCS) development

GE Renewable Energy developed a wide area monitoring and control scheme (MCS) to deliver coordinated fast frequency response. This concept has not previously been demonstrated on Great Britain's (GB) electricity power system. The MCS delivers sub-second detection and response triggering from multiple resources to system frequency events in a coordinated way that optimises their performance characteristics. This potentially allows more technologies to access a fast frequency response market, which will be increasingly important in low system inertia conditions.

A new hardware platform that could perform fast, real time and deterministic control functionality was developed and successfully interfaced with the different control systems at commercial sites. The functionality of the MCS has been validated to prove it can provide sub-second targeted response proportionate to the system frequency event. The MCS performance was validated independently by academic partners (Universities of Manchester and Strathclyde) and at the commercial trial locations.

This section provides an overview of the MCS integration and performance at commercial partners' sites. Detailed performance analysis is presented in the '*Data Review and Performance report*'.

Key findings
- The commercial field trials were important in identifying how the MCS could interface at different operational sites and trigger response to real system frequency events.
- The Local Controllers (LC) event detection function block was sensitive to the RoCoF setting which may differ from site to site. This difference in RoCoF was due to variations in system inertia across the electricity network.
- The control platform and applications were found to be reliable. The installed controllers had a low rate of failure during the trials and an availability of 99.957% was recorded.
- P-class Phasor Measurement Units (PMUs) would be required for wide area control schemes due to them having a significantly reduced data filtering latency compared to M-class devices.
- The Technical Readiness Level (TRL) of the MCS is six (prototype development and demonstration).

Evaluation of the MCS performance

The MCS performance at each commercial site was monitored and evaluated based on the data received; the outcomes of this assessment are detailed in the '*Performance and Control Scheme Data Review report*'.

A summary of the key findings from the different trials is as follows:

i. BELECTRIC field trials
The site configuration, including communication links with the LC, was complex and posed a variety of challenges, for example IT hardware failure which required additional time to resolve before the trials began. BELECTRIC trialled a lower RoCoF threshold, based on the experience from the other partner sites. The testing confirmed that a RoCoF threshold of 0.04Hz/s was the more suitable setting at this site, as the MCS was triggered by several genuine large frequency disturbances

ii. Flexitricity field trials
Flexitricity installed a LC at the Static RoCoF site. The initial RoCoF threshold setting agreed was 0.1Hz/s, however no genuine frequency events were detected by the MCS using this setting. The threshold was reduced to 0.08Hz/s so the LC could detect and respond to system frequency events.

The LC did not perform as expected and after investigation the main causes for this were found to be:

- Frequency measurement noise
  Frequency measurement noise can lead to spurious detections of frequency events by the MCS, highlighting the importance of data quality. One potential solution is to redefine the technical requirements of the devices used to measure RoCoF in terms of how they filter system frequency signals. A second solution is to modify the event detection algorithm so it identifies noise and prevents false detection. This second solution was implemented, improving the overall performance of the LC.

  Either solution would impact the overall coordination of frequency response across the network. Further investigation is needed to ascertain the effect of frequency noise filtering on the MCS's performance.

- Data transfer
  The Static RoCoF trial identified frequent data losses between the PMU and LC, and between a trial site and the Flexitricity server in Edinburgh. The missing data between the PMU and LC at the Static RoCoF site led to inaccurate RoCoF calculations. Further investigation showed that the LC was not receiving all the data from the PMU. Without a suitable device to monitor the data traffic between the PMU and the LC, it was not possible to determine the specific problem. One probable cause of this issue could be the hardware between the PMU and the LC which could be mitigated by using a filtering mechanism in the event detection algorithm. Alternatively, the internet connection itself could have contributed to the LC not receiving all the PMU data.

iii. Centrica/EPH field trials
The field trials at South Humber Bank power station used the same 0.1Hz/s threshold as originally used by Flexitricity, with no events detected for the closed-loop testing before the trials were suspended due to operational restrictions at the plant.

Although the trial did not demonstrate closed-loop operation, it was used to evaluate the overall LC for three months. However, one issue related to the logging functions was found, where logs would not store and update correctly. A fix was created for this and was rolled out during the project extension period.

PMU performance
The performance of M-class PMUs at all locations was reviewed. M-class PMUs have a long filtering (measurement) window of up to 300ms which can translate into delays in the data coming from the PMU. From the PMUs installed for the trials, a delay of approximately 140ms was recorded from when a data packet was sent from the PMU. This performance was in accordance with the IEC C37.118 standard and means that when a data packet is sent from the PMU, it is already 140ms old. This must be considered in the total time permitted between the PMU measurement, RoCoF calculation and service provider response.

A similar test was performed on a P-class PMU and it was found that the latency was reduced from 140ms to 40ms. It is recommended that for a wide area control schemes where network delays are likely to be an issue, P-class PMUs must be considered.

Monitoring and control scheme performance
The event detection algorithm in the LC and the resource prioritisation algorithm in the Central Supervisor (CS) were updated during the trial. The event detection application functional block (AFB) was updated because of the PMU frequency noise issue. The CS update was provided to the Universities of Manchester and Strathclyde, as these were the only locations using this MCS functionality.

Technology Readiness Level of the monitoring and control scheme
At the time of the EFCC project bid, the overall Technology Readiness Level (TRL) of the MCS was judged to be between six and seven. This was on the basis that the project would require new control logic and the development of a new control platform. During the project, the change to a distributed MCS structure (as detailed in Chapter 6 of this report) meant that different control logic needed to be implemented and tested. The project has successfully implemented and validated this revised control logic, and the system TRL is now rated at six (prototype development and demonstration).

MCS performance validation

How the MCS performed against various future system scenarios was extensively validated. Through comprehensive tests it was identified that several potential issues could compromise its performance, e.g. potential delays in control action due to internal signal filters, compatibility of communication interfaces, or selection of optimal data buffering window size. These issues were reviewed by GE Renewable Energy who improved the design of the MCS. Updated MCS firmware was validated under a wide range of frequency and non-frequency disturbances to test its reliability and security, increasing the confidence of the system. Specific communication tests at PNDC enhanced the understanding of how communication performance can affect the wide area operation of the MCS and specified the communication performance required to support the operation of the MCS.

Key findings
- A robust process for testing and validating a wide area control systems was developed. This could be applied to other systems such as complex active network management schemes.
- The MCS can more effectively contain frequency events in a quicker timeframe than traditional primary and secondary response.
- The MCS delivers the appropriate active power response to the area of the network where the disturbance occurred.
- The MCS can actively coordinate response across the network to contain the frequency disturbance in the

absence of sufficient resources in a region.
- The ramping down of faster response needs to be coordinated with slower acting response services.
- To achieve 90% confidence level, the MCS can maintain wide area visibility to make correct decisions for 500ms after an event, the communications network jitter needs to be kept to 10.2ms for a mean latency of 60ms and 13ms for a mean latency of 50ms.

The main learning points from the simulation and physical tests carried out are outlined in the remainder of this section.

Evaluation of the MCS response

A series of tests were carried out to evaluate how the MCS can benefit frequency containment, and the importance of the response location in low inertia systems.

Figure 25 shows an example of test results that compare the system frequency profile with and without the MCS when a frequency event is simulated in different locations on the NETS. In this example, for Test 3 (a simulated 1GW generation loss in Scotland), the event occurred in the same region as the LC1, while in Test 1 (a simulated 1GW generation loss in England), the event occurred in the same region as LC2.

The tests confirmed the MCS will react differently depending on the location of the frequency response on the network as shown in Figure 25 (b) and (c). The resource located in the region where the event occurred responded faster than resources located in other regions. The benefit of the MCS in containing frequency was demonstrated in the tests, with the frequency nadir contained to above 49.5Hz compared to 49.3Hz without the MCS, see Figure 25(a).

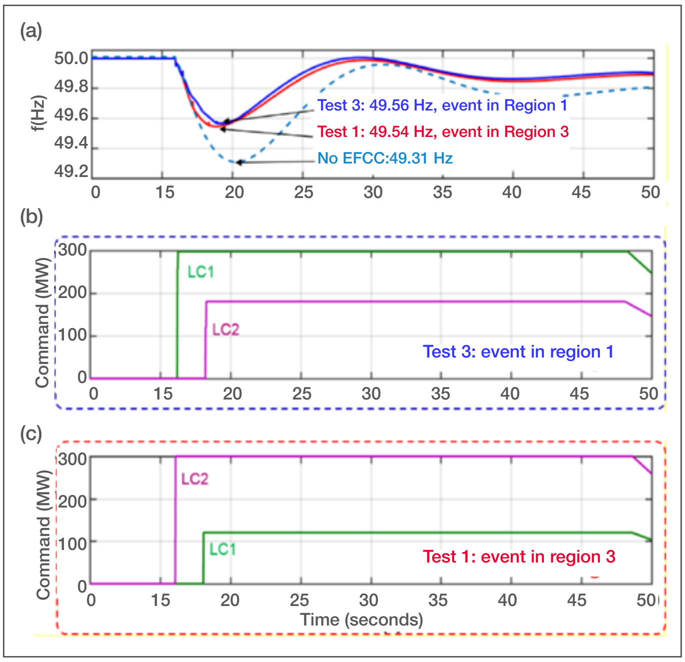

Figure 25: Example test results for evaluating the performance of the EFCC scheme

Local (back up) operation mode of the MCS

The University of Strathclyde conducted tests to evaluate the performance of the MCS when the LCs completely lose communication with the other devices. This means the controllers can operate in local operation mode where only local measurements are used for decision making.

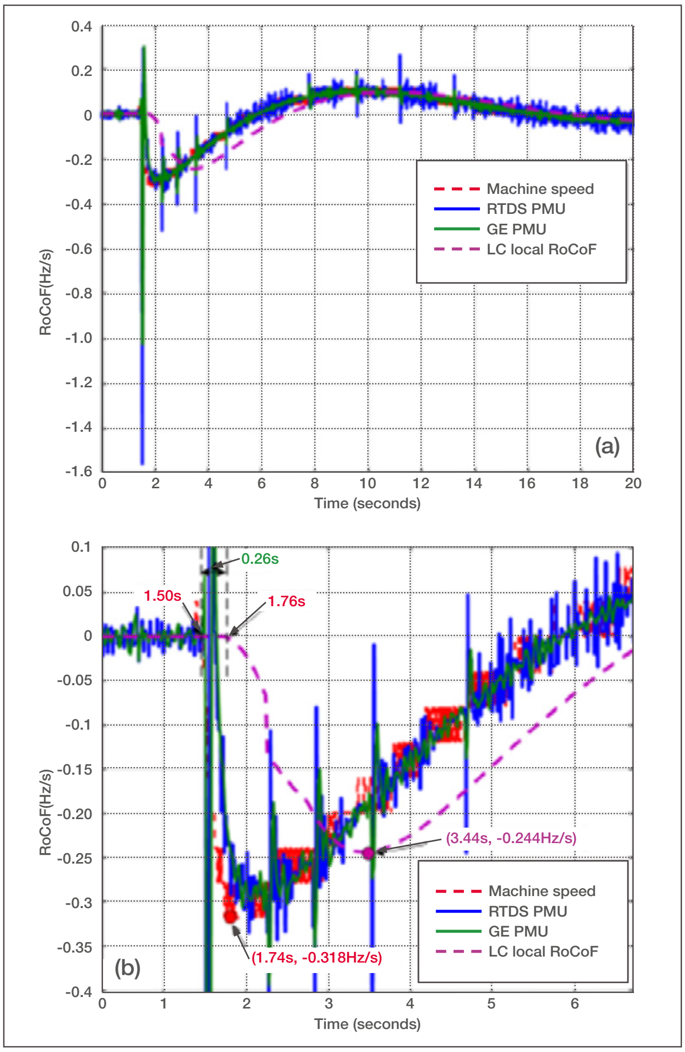

Figure 26: RoCoF measurements for 1GW generation loss (Region 3)

It was found that when the MCS is operating in local mode, although not as effective as operating in wide area mode, it can still provide a level of support to enhance the overall frequency control on the network. This is because in local mode it generally takes longer for the controller to issue control actions because of the use of internal signal filters. Figure 26 shows a simulation result for a RoCoF measurement due to a 1GW loss of generation where the low pass filter delays the event detection in the LC.

Methods were developed to configure local mode settings that accounted for the system inertia level and resource response capability to make sure the resource would be delivered to avoid low frequency demand disconnection (LFDD). Figure 27 shows the benefit of local mode operation to avoid LFDD.

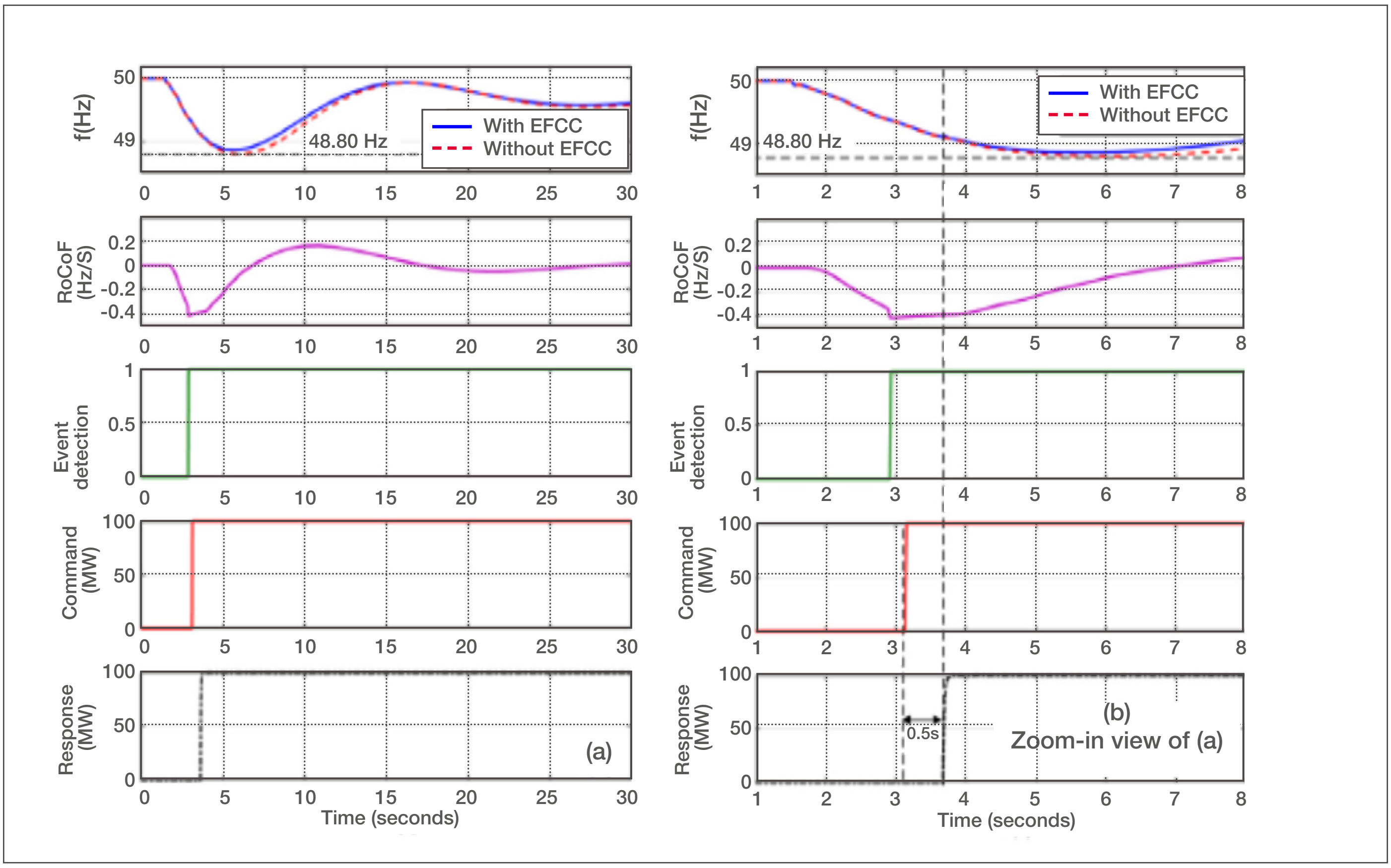

Figure 27: Test results for both frequency and RoCoF thresholds that are enabled in resource allocation block – 82 GVAs

Impact of voltage on the MCS

The voltages at different substation busbars during a fault event are widely depressed and strongly impact the NETS. This can lead the MCS to trigger because of the rise and fall of frequency caused by the short circuit fault. The minimum fault blocking time setting in the controller can be modified and used to resolve this problem. The minimum fault blocking time can be increased to avoid MCS maloperation when facing severe short circuit faults. However, by increasing it, the disadvantage of undesired delays of the MCS also needs to be considered.

Ramping of service provider response

The impact of service providers' volume and ramp rates was assessed. It was found that a larger volume of response can give better results to minimise the frequency nadir for an under-frequency event. The ramp rate of response should be carefully adjusted or coordinated with other service providers to ensure a smooth handover with generator governors. Figures 28 and 29 show the results of sensitivity analysis of service providers' volume and ramp rates.

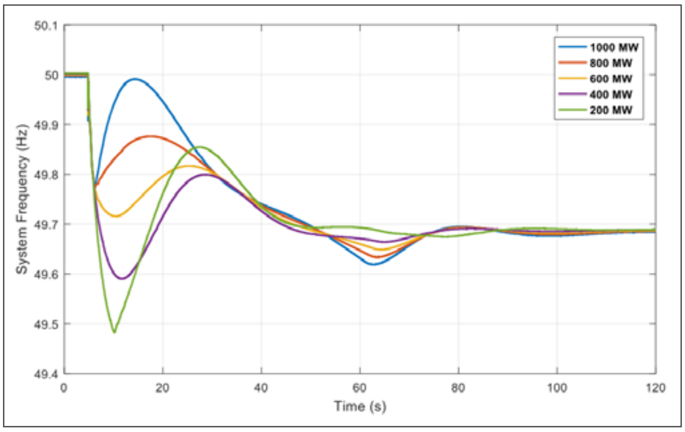

Figure 28: Test results for the amount of service provider response

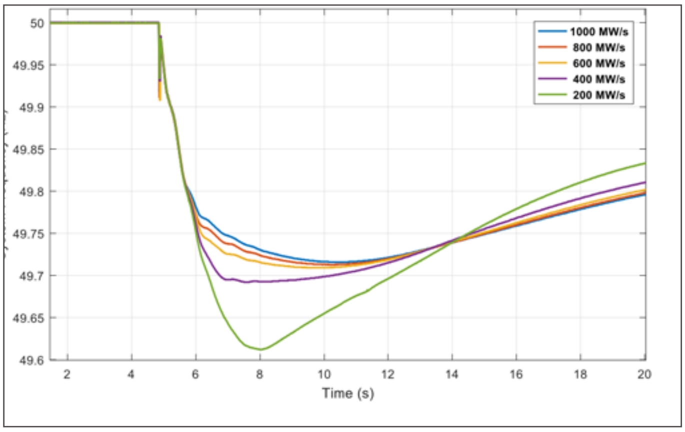

Figure 29: Test results for the ramp rates of service provider response

Weighting of PMUs and frequency aggregation

Sensitivity analysis on the weighting of the PMUs showed that the number and the placement of the PMUs in the power system could lead to a different aggregated system frequency, which might affect the MCS.

In addition, measurements that are aggregated on a regional basis need to be approximately coherent, otherwise the locational impact on frequency may not be detected. This can affect the accuracy of the weighted average derived in the RAs and the performance of the MCS. Any unforeseen factors such as data loss, or loss of generation or demand in a region could exacerbate any issues with inaccurate measurements.

Further studies with more PMUs should be considered in the future to investigate these areas.

Communications system requirements

The communication tests investigated how the MCS operates with different levels of communications network degradation. The results identified the minimum requirements for stable operation of the MCS. It was found that:

- the maximum latency the MCS can tolerate was subject to the selection of the data buffering window. For a buffering window of 100ms, the system can tolerate 78ms of latency. If the latency is greater than this value, it can be addressed by increasing the buffering window accordingly. However, increasing the buffering window could lead to a longer decision-making time. There will be a compromise between the speed of operation and the capability to tolerate any communication delays. Additional communication performance characteristics like BER (bit error rate), latency with jitter, and loss of packets was tested. These are detailed in the '*Impact of Communication Performance on the EFCC Scheme Operation*' report published on the project website.
- Figure 30 shows an example of the test results for evaluating the MCS performance during emulated latency and jitter tests. In this case, the buffering window was set at 100ms with a mean latency of 78ms and a jitter level of 26ms (representing an extreme communication degradation scenario). At this level of latency and jitter, LC1 missed packets from two Regional Aggregators (RA) for the majority of the test period (confidence level dropped to 33.33%). In some cases, LC1 missed data from all three RAs (confidence level dropped to 0%). As a result, LC1 lost wide area visibility most of the time during the test - this is evident in the second plot where the RoCoF quality frequently dropped to 0 and in the third plot where the system frequency measurement at LC1 also frequently dropped to 0.

However, when the frequency event occurred, the test results show that the MCS controllers can still detect the event promptly and respond correctly to the event, like the base case where the communication links were operating under ideal conditions, which is also shown in Figure 30.

Further communications tests found that the statistical nature of jitter would lead to the LCs behaving inconsistently. Mathematical analysis was conducted to evaluate the probability of whether the MCS can function as required at different latency and jitter levels. Specifically, to achieve 90% confidence that it can maintain wide area visibility to make correct decisions for a period of 500ms following an event, the jitter needs to be controlled within 10.2ms for a mean latency of 60ms, and 13ms for a mean latency of 50ms.

In random loss of packet tests, it was found that as the loss of packets rate increased, the MCS became more likely to experience compromised behaviours. To achieve 90%

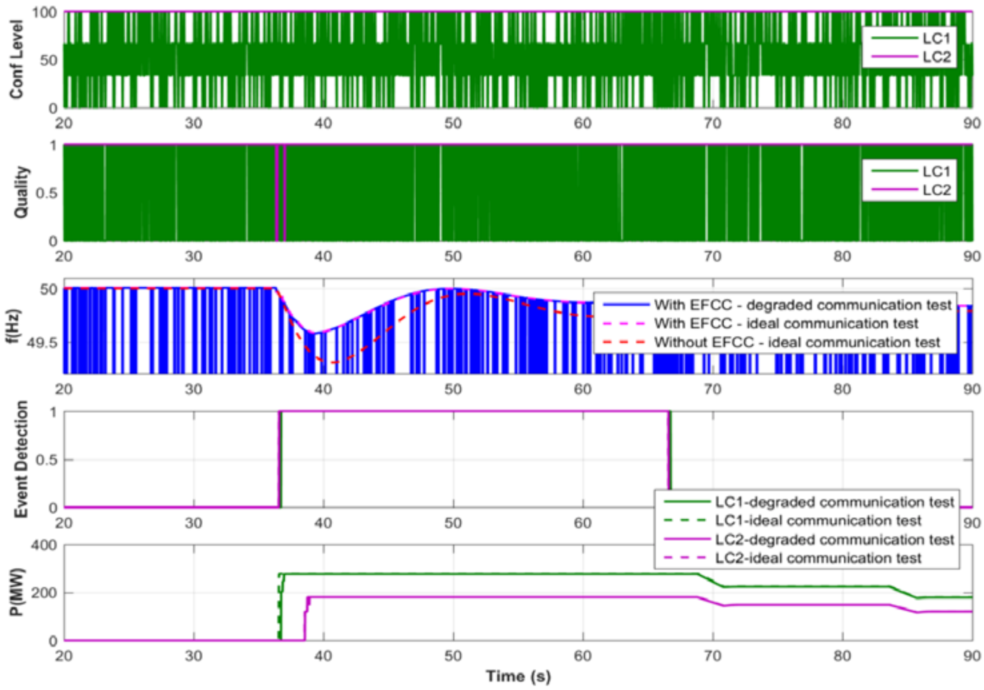

Figure 30: Example test results for evaluating the impact of communication jitters on the performance of the EFCC scheme

confidence that the MCS will make correct decisions for a period of 500ms following an event, the loss of packet rate needs to be smaller than 3.8%.

Bit error rate (BER) tests in wide area mode found that if the BER exceeds 10-2, the data from the PMUs on the electricity system will be discarded by the RAs. For the communications links between the RA and LC, if the BER exceeds 10-5, the LC will discard the data it receives. It was also found that a BER of 10-5 for wide area mode is the limit at which the MCS can still exhibit a desirable behaviour during frequency and fault disturbances.

Practical guidelines for implementation
The project has significantly benefited from validating the MCS in both real-time simulation and realistic physical testing environments. This has provided learning around the practical implementation aspects of the scheme.

At the Power Networks Demonstration Centre (PNDC), the realistic testing environment with standardised communication protocols and industrial standard equipment, identified and demonstrated potential issues that could be experienced during the actual implementation of the MCS. For example, it was found that the speed of the MCS response could be largely affected by the proprietary controller of the resources receiving control commands from the MCS. Implementation of the proprietary controller could be significantly different between manufacturers and the delay introduced by the proprietary controller is not necessarily constant. Therefore, a comprehensive process for characterising the service provider capability along with the controller's behaviour will be required for rolling out the MCS. Similarly, there are likely to be differences in the implementation of standardised communication protocols, which could lead to issues in the interpretation of communication data, especially for GOOSE (Generic Object Oriented Substation Event) messaging for IEC 61850 that can be used to transmit data between different substation locations. An extensive range of similar learnings from the project would not have been possible without a realistic testing environment and comprehensive test programme.

The use of the Real Time Digital Simulator (RTDS) and dynamic models at the University of Manchester has shown that in low inertia conditions, system disturbances are seen differently in relation to the location of frequency events. This finding directly influences the location of the PMUs used for the MCS to inform any deployment strategy, and impacts their technical specification (i.e. accuracy of measurement) as well as how these measurements are weighted within the MCS. Therefore, for practical implementation, it is suggested that further studies on PMU placement and weighting in the electricity transmission system are conducted to fully optimise the operation of the MCS. It is also noted that the short-circuit fault has a different impact depending on the location, and the load voltage dependencies would largely affect this characteristic.

Technology assessment for fast frequency response with the MCS

Demand side response (DSR)
The tests conducted by Flexitricity have confirmed that Dynamic RoCoF and Static RoCoF are technically feasible and an effective means of using DSR to stabilise system frequency in low inertia systems. A key consideration for a demand side provider is that their service offering does not lead to excessive use, and the service being introduced leads to a predictable level of disruption.

Key Findings
- The variability of RoCoF measurements between locations requires site-specific tuning of the trigger settings.
- High cost measurement equipment can be replaced with lower cost alternatives to provide fast frequency response.
- For Spinning Inertia sites, the governors may respond too quickly to frequency deviations; alternatively they could be given a control signal derived from locally measured RoCoF to trigger response delivery.
- Dynamic RoCoF sites can provide a response between 200ms and one second. Calibration of the power output is particularly important and where the site load is inherently non-linear, a correction to the power deviation signal is required.
- Static and Dynamic RoCoF sites have suitable operational characteristics for taking part in any potential RoCoF service if it is economically advantageous for them to do so.

Static RoCoF
The Static RoCoF site ran a mixture of open-loop and closed-loop operational modes. The trials showed that it is a viable service, in that the site has confirmed that a load can be set up to respond to a RoCoF signal in an overall response time of less than 1.5 seconds. This response can be coordinated by the MCS with other faster response services to contribute to the overall recovery of system frequency.

The original trip settings within the MCS were deliberately set to be conservative against current RoCoF levels. These settings were then adjusted during the trial with the aim of achieving the desired activity level of 10 trips a year. The adjusted settings were closer to the desired level. The trial was too short to be able to say if the settings required further refinement. In addition, the site saw inconsistent RoCoF triggering to system frequency events due to frequency measurement noise and data loss between the LC and PMUs as described previously.

Figure 31 shows an example of a RoCoF trip based on a system frequency event. The RoCoF threshold was breached overnight at 02:42 and the event detection algorithm in the LC initiated a signal to the site approximately 40ms after the 80mHz/s RoCoF threshold was broken. Investigation of the site control module estimated that the time between the RoCoF initiation signal and the site reducing its power output is approximately 750ms. A delay in the metering signal means that a more accurate recording of

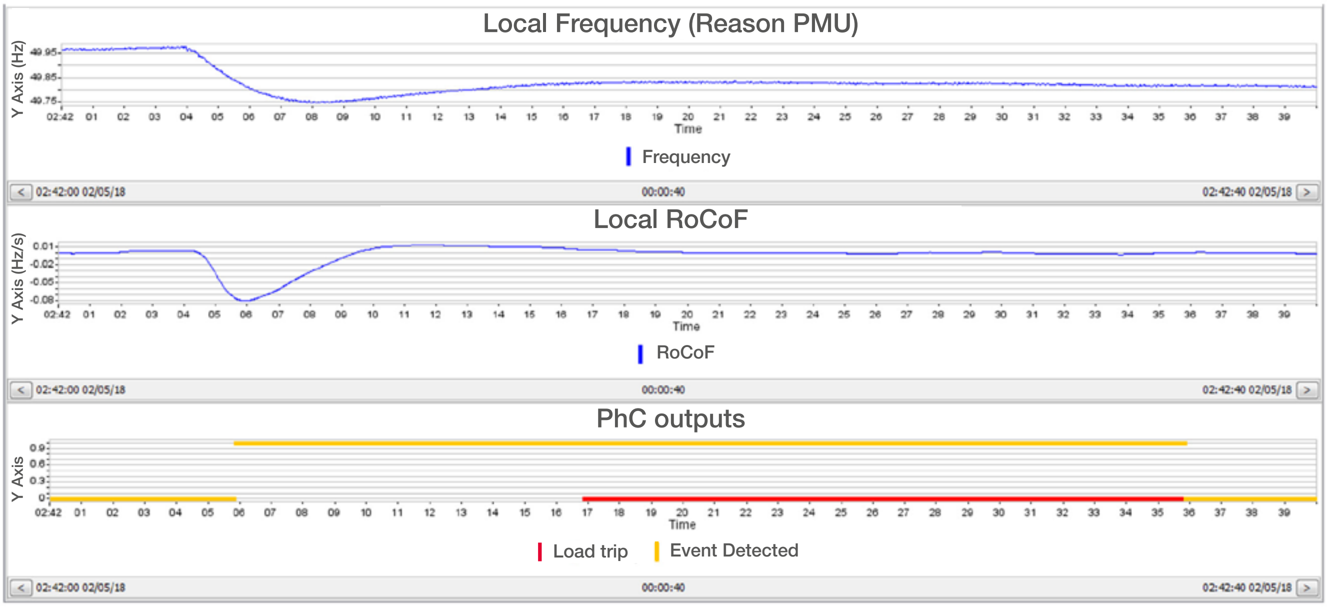

Figure 31: RoCoF trip event at the static RoCoF site at 02:42

the time between RoCoF signal and change in power output could not be achieved.

The trial site had intermittent but generally predictable availability. It seems reasonable that its participation in any potential Static RoCoF service could be negotiated. It is also realistic that several of Flexitricity's current partner sites would have suitable operational characteristics for taking part in any future service, although it would need to be economically advantageous for them to do so.

Consideration must be given as to whether the control systems that were used for the trial would be suitable for any potential balancing service. This decision would need to consider the performance requirements and qualification testing for the service.

Spinning Inertia

Spinning Inertia from synchronous embedded generators like combined heat and power (CHP) engines does not naturally deliver the type of frequency response required when the output power controls are configured in a standard way. CHP engines have the capability to significantly adjust their generation output in a sub-second timeframe. However, their natural behaviour in response to system disturbances may not be perfectly aligned with the needs of the electricity transmission system. Instead, active control of synchronous embedded plant should be explored, in a similar manner to Dynamic RoCoF.

It is known that all synchronous machines, including smaller CHP engines, exhibit oscillations when a major disturbance occurs on the electricity system. However, during the trial it was noted that, at times, the inertia contribution of the engines appeared to be in phase with the frequency response requirement, while at other times it appeared to be out of phase with it. This inconsistent effect may be a result of successful and rapid governor control at the CHP engines.

During commissioning, it is normal for closed-loop control systems used at CHP sites to be set with a slightly underdamped response. This typically achieves the best compromise between speed and stability. However, this may result in the governors responding too quickly to the frequency deviation and oscillating slightly around the target set point.

CHP engines could be given a control signal derived from locally measured RoCoF which directly causes a RoCoF-triggered frequency response. This would be an application of Dynamic RoCoF to high-load-factor generation, trialled during this project.

Dynamic RoCoF

Dynamic RoCoF sites were shown to respond no slower than one second, and within 200ms at the fastest site. It is possible to provide Dynamic RoCoF through aggregation of assets at third party sites and to deliver positive and negative capacity in response to changes in locally measured RoCoF.

Based on the units taking part in this trial, the availability of capacity can vary considerably during the day. Development of algorithms to predict the available power for any given moment could be incorporated into the service delivery. To create diversity and increase predictability of service delivery, a wider range of types of Dynamic RoCoF than those selected for the trials could be used. In addition, calibration of the power output is particularly important. Where the site load is inherently non-linear, a correction to the power deviation signal is required.

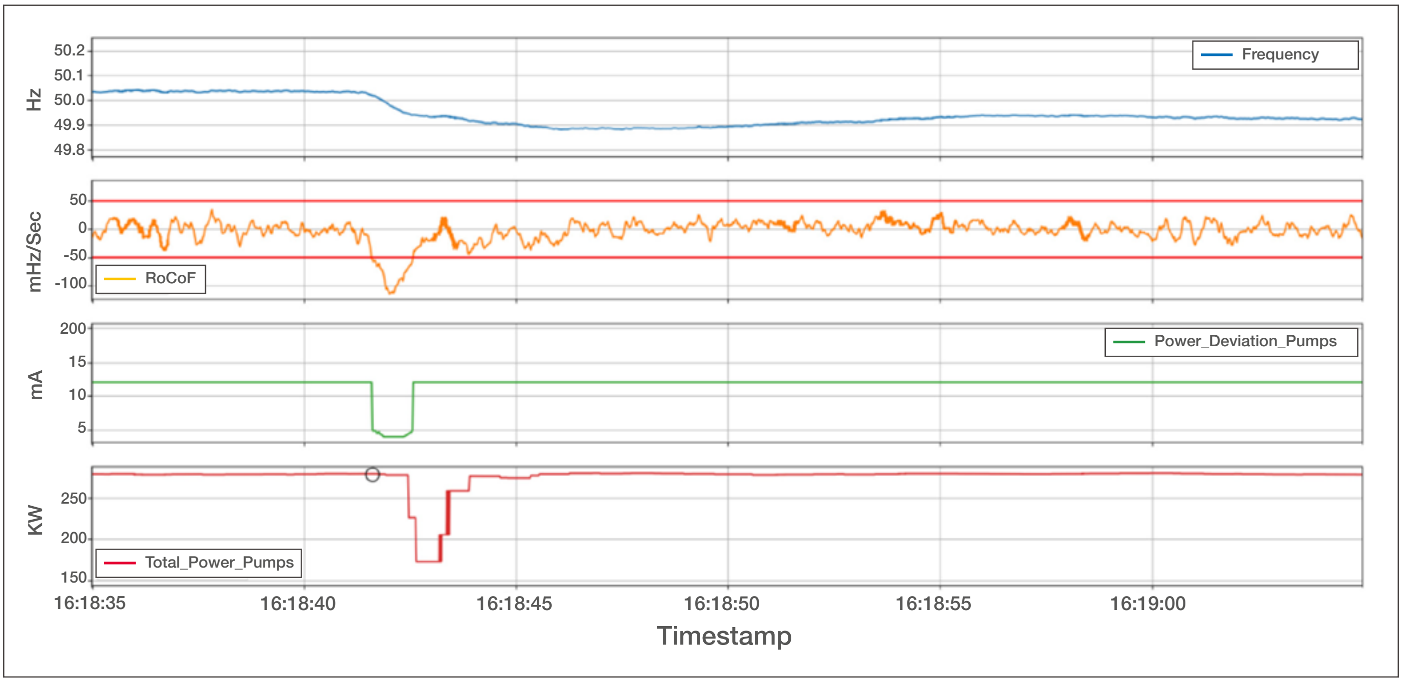

Figure 32(a): Negative RoCoF event at the waste water pumping station

A vital issue for a Dynamic RoCoF site was the speed of response of the equipment. This contains two components: the speed of RoCoF calculation and the speed of action from the equipment. During this trial, the typical speed of calculation – from a RoCoF event to a power deviation signal – was around 0.02 seconds. The speed of response of the equipment is then a site-specific parameter. It takes approximately a further second to provide a power response at the waste water site pumping station compared to 200ms at the cold store facility. Figures 32 (a) and (b) show example response times of the pumping station and the cold store facility respectively. In the figures, the upper traces show the system frequency (blue) and system RoCoF (orange), followed by the power deviation request signal (green), and the actual change in power output (red). No optimisation of the control parameters of the sites' internal control systems was carried out.

At the cold store, the power deviation signal was wired directly into to the compressor controls rather than through

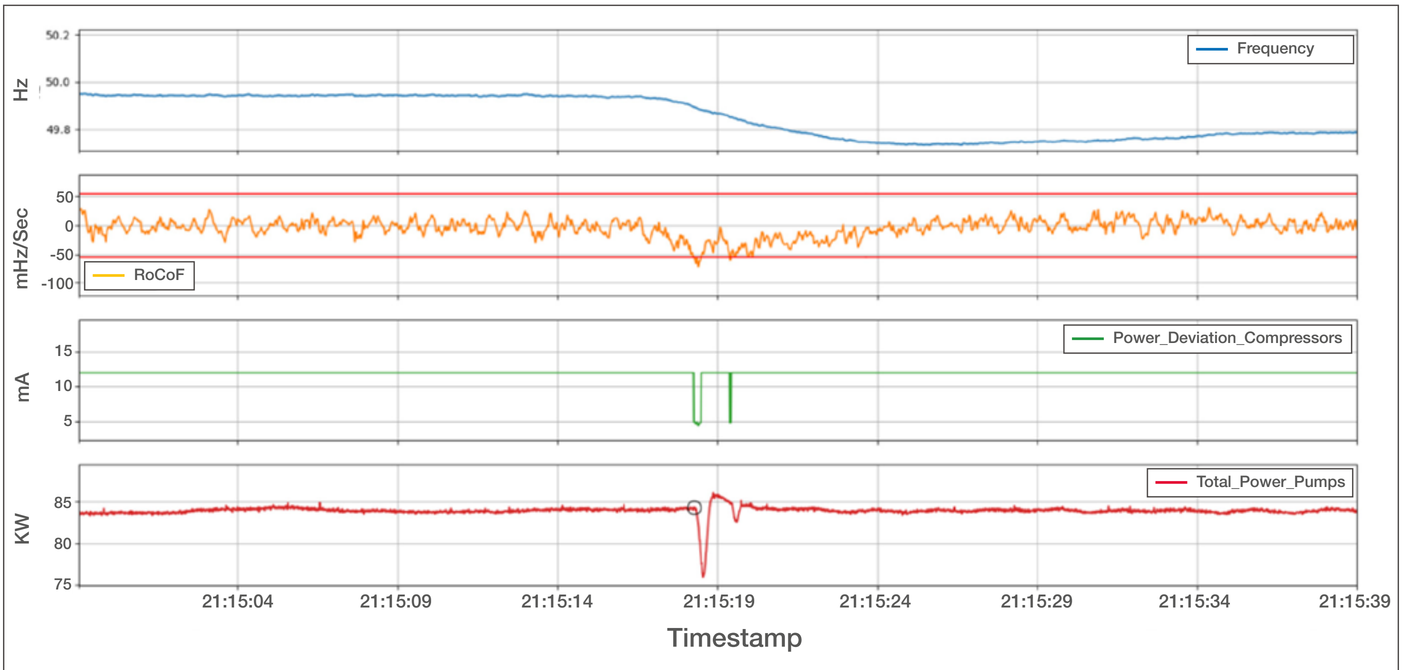

Figure 32(b): Negative RoCoF event at the cold store facility a Programmable Logic Control (PLC) controller. This control method may be partially responsible for the consistently faster response from the cold store. The cold store's faster response also allowed it to respond to shorter duration events and to return to normal more quickly after the RoCoF had returned to zero. In addition, internal control parameters within the sites' control systems may be deliberately slowing down the response, purely because there was no need for faster response before the project.

Different locations can display significantly different RoCoF behaviour, even if they are relatively close geographically, so different sites would require alternative trip settings. It would be difficult to know how many responses would be triggered by a given set of RoCoF parameters, or what parameters would be required for a given level of response, without prior local data collection. Site 'tuning' is likely to be needed to determine the best control parameters for any given site. Further work is needed to better understand how this can be achieved for triggering DSR via the MCS.

Large-scale generation

Grid Code primary response mandates that plant should respond to a frequency offset from 50Hz (kDF) within 10 seconds. The modified concept, developed as part of the project, showed that the response time could be reduced by approximately 30% using RoCoF to predict the load change and maintain this load until the other response services took over.

The revised frequency control logic using RoCoF as an input rather than a deviation in frequency from 50Hz was installed in one (GT-21) of the two gas turbines at South Humber Bank. Initially for 12 months, the logic was not driving the plant response and was working in a passive mode. Throughout this period, it was possible to review any significant frequency deviations that occurred on the electricity transmission network and compare the conventional frequency response logic, as well as the revised frequency control logic. Review of these events consistently showed that the revised frequency logic would give more response in the sub-10s timeframe of a significant frequency event.

Figure 33, below, shows the plant's improved response time.

Connectivity between the GE Renewable Energy equipment and the GT controllers was tested, proving that remote dispatch is possible.

Key finding

- Revised logic developed and tested which delivers a 30% increase in the speed of CCGT plant response based on a RoCoF threshold.

Improved modelling capability

An existing offline simulation tool was adapted during the project through the use of VBA (Visual Basic for Applications) coding and protocol translation, to allow actual frequency events to be input directly. This allowed the actual control system code response to be observed and analysed against real world events. Previously, the simulation application could only use standard Grid Code compliance response characteristics.

Response optimisation – offset tracking

During a frequency event simulation, the RoCoF-based response was initially more than required. A real event showed the need for tracking to take into account the effects of any offset from 50Hz that may already exist (at the start of an event), so the RoCoF-based response would be effective in delivering improved response times. The tracking was optimised, fully incorporated into the design and successfully tested.

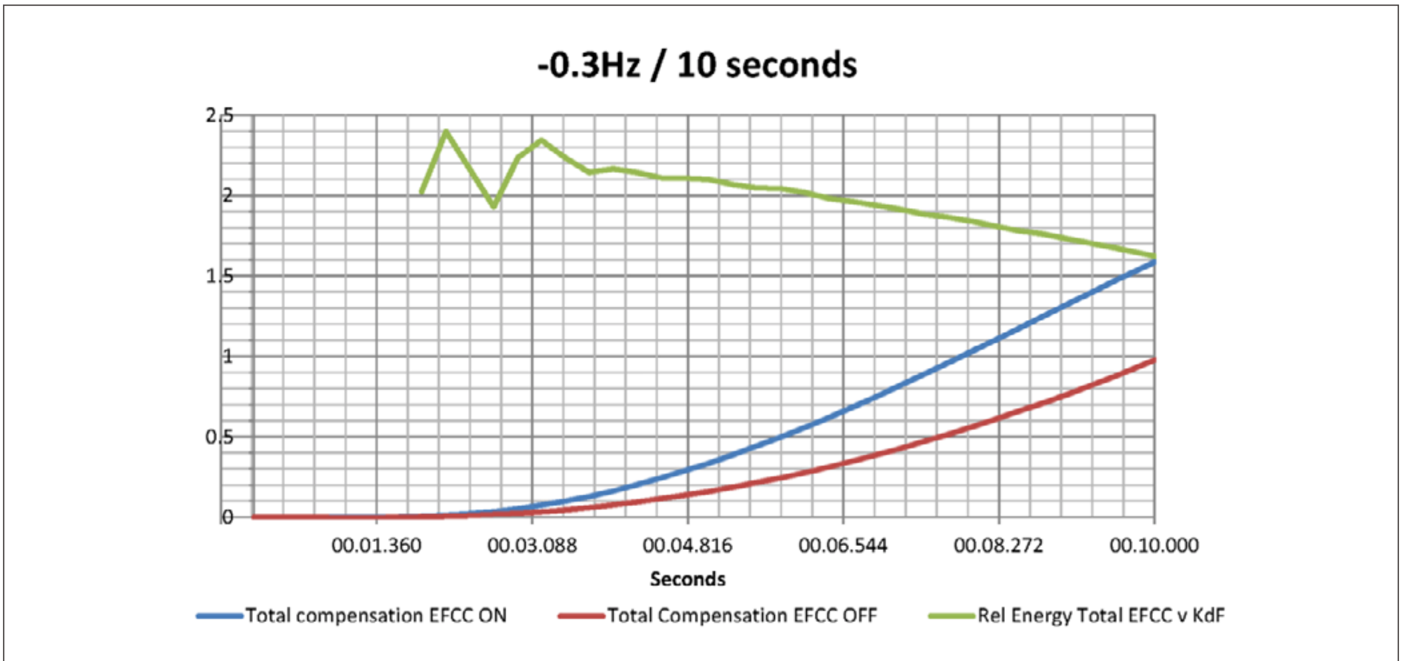

Figure 33: Improvement in response delivery in the first 10s of an event during testing

Limited Operational Notification
It was agreed with NGESO that a Limited Operational Notification (LON) would be drawn up to enable the revised (RoCoF-based) logic to be used for active frequency response on GT-21 only.

Unfortunately, during the periods in which South Humber Bank was instructed to carry frequency response by the normal market mechanism, no significant frequency deviations occurred, so the effectiveness of the revised frequency response logic could not be observed. It should be noted that this is not surprising as the module did not run continuously during this period and, like most CCGTs, it is only used for frequency response for a portion of the period it is running.

Solar PV power plant

BELECTRIC provided a RoCoF-triggered frequency response using a large-scale solar photovoltaic (PV) farm located in Willersey. For solar PV to be considered for integration with the MCS, a forecast system was developed to determine the plant's available power and communicate it to the LC installed at the site. A statistical forecast approach achieved a high accuracy of over 95% for 15 minute forecasts, which optimised reaction time and processing speed of the forecast model.

A 1MW/1MWh battery storage unit was installed in the vicinity of the solar plant to investigate the benefits to frequency response when the control systems of both plants were fully integrated. This hybrid system also provided a RoCoF-triggered response and allowed a range of operational regimes to be considered (for example having the battery unit at a 90% state of charge during daytime and 60% state of charge during night time).

The following sub-sections detail a selection of the trial results. All tests can be found in the '*PV Standalone, MATLAB Hybrid Model Simulation*' and '*PV- Battery Hybrid System*' reports on the project website.

Key findings
- Solar PV reaction times were on average 880ms until full response after receiving the data from the LC; a best case of 120ms was achieved. Retrofitting control systems would be needed to achieve a faster response.
- The communications interface between the solar PV inverter and the control system can restrict the use of the plant for fast frequency response; data traffic on the MODBUS communications protocol resulted in slower than expected reaction times.
- Solar irradiation statistical forecasting and plant modelling can be used to inform the availability of the solar PV plant. Accuracy of these forecasts range from 98% accuracy for a five minute forecast to 48% accuracy for a 60 minute forecast.
- A hybrid solar PV and battery unit can provide additional frequency response support. A potential combined operating regime between solar PV and battery could have the battery providing the fast reaction part of an overall response.
- For 2014 central converter based solar farms, an update of the communication system and a retrofitting of the PV farm – with a good network design and fast switches – is necessary to provide fast frequency response.

Solar PV forecasting
Initially forecasting was based on a cloud measurement camera and cloud movement interpretation algorithms. However, the first tests with the cloud movement camera did not produce the desired forecast accuracy of over 95% for a 15 minute forecast. Also, the processing time of the system introduced a longer reaction time because the algorithm calculated the future irradiance using another software program.

To improve the reaction time and the availability of the forecast, the forecasting approach was changed to a statistical forecast directly implemented in the control software. This improved the processing time as well as the overall system reaction time.

The model was set up to slightly under-forecast the amount of power available and the forecast was never allowed to reach 100% of maximum power. This was to ensure that availability information given to the LC would be slightly conservative. There is a confidence level associated with forecasting errors in the method used that were shown to be very low, depending on the probability value.

Figure 34 shows the forecasted power output compared to the actual output of the solar PV plant.

The blue line in Figure 34 represents the actual power output by solar plant inverter, and the orange line represents the calculated power by the underestimating statistical forecast model. The model is fairly accurate for different weather situations. Days two and four in Figure 34 were quite cloudy (with a constantly changing irradiance and power output), contrary to sunny days five and six. The accuracy varies widely for the different variations of forecast duration time and size of data samples – from 98% accuracy for a five minute forecast with large data samples down to 48% accuracy for 60 min forecasts with small data samples.

A MATLAB model was used to simulate the characteristics and behaviour of the various components of the solar PV power plant. This model allowed further analysis to evaluate how beneficial reducing the power output of the plant below its maximum power point can be to frequency response. By modifying the control system to reduce the output below the maximum operating point, either a positive or negative frequency response is possible. In combination with the forecast system, the availability of both positive and negative power over the next one to 60 minutes was given to the LC.

Figure 35 shows the accuracy of the solar PV MATLAB model.

Sudden changes in irradiation, such as cloud movement, lead to short reductions in accuracy. In general, the accuracy

Chapter 4

of the Rainbows solar PV farm model was found to be above 95% in comparison to the actual power output.

Solar PV response

For the stand-alone solar PV, experiments were conducted by reducing the power output and ramping up the power to deliver positive frequency response. This requires the system to know how much power could be delivered at maximum power point (MPP), so there is a certain amount of power reserved for response. For negative response during over-frequency events the power generation was reduced.

The frequency response times were found to:

- take an average of 880ms until full response after receiving data from the LC
- have a fastest response time of 120ms
- have a worst case response time of 2140ms.

The longer response times are due to the plant's specific current-voltage characteristics, as well as low-pass filters in the inverters which are there to prevent oscillations. Another factor that affects the reaction time is the MODBUS communications protocol used at the site. The tests found that the data traffic between the control system and the PV

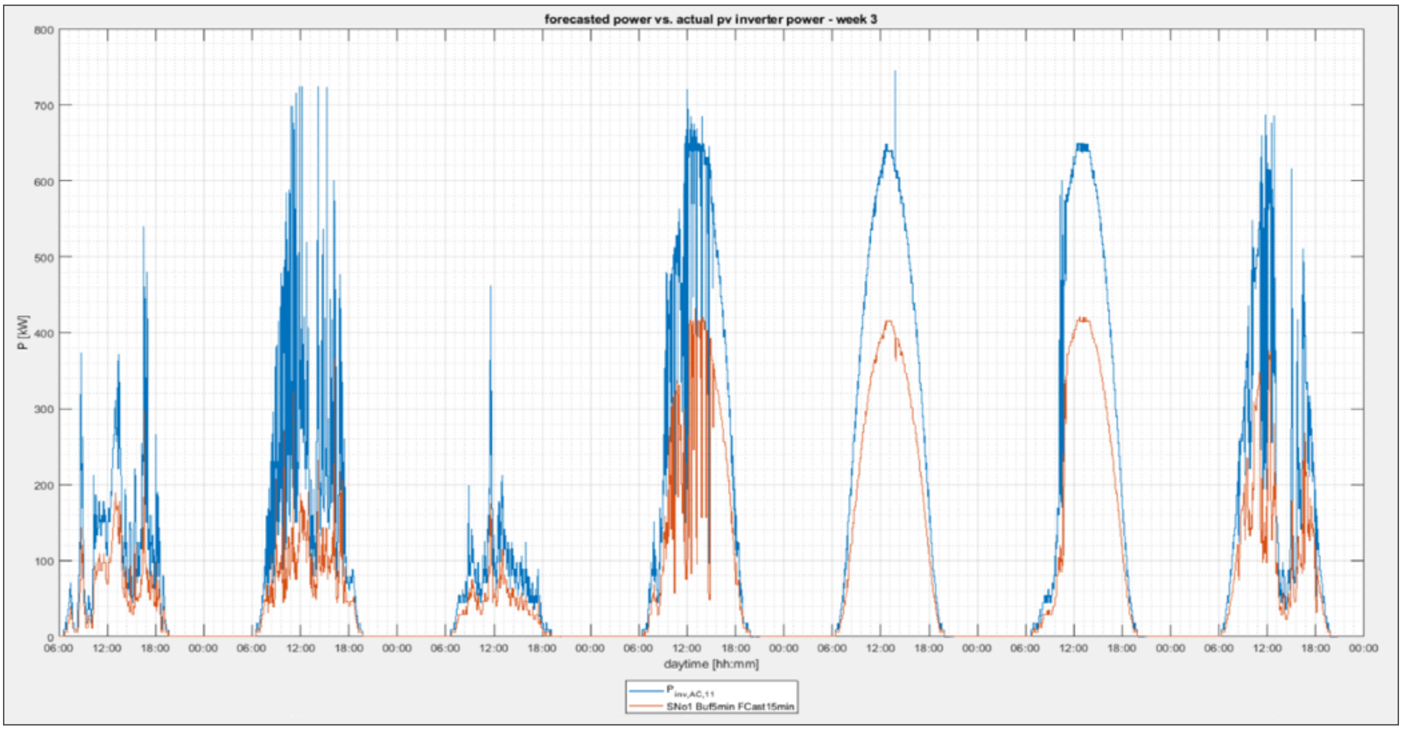

Figure 34: Real power output (blue graph) vs. forecasted power output (orange graph) for irradiance data during one week in April 2018 at the Rainbows solar PV farm

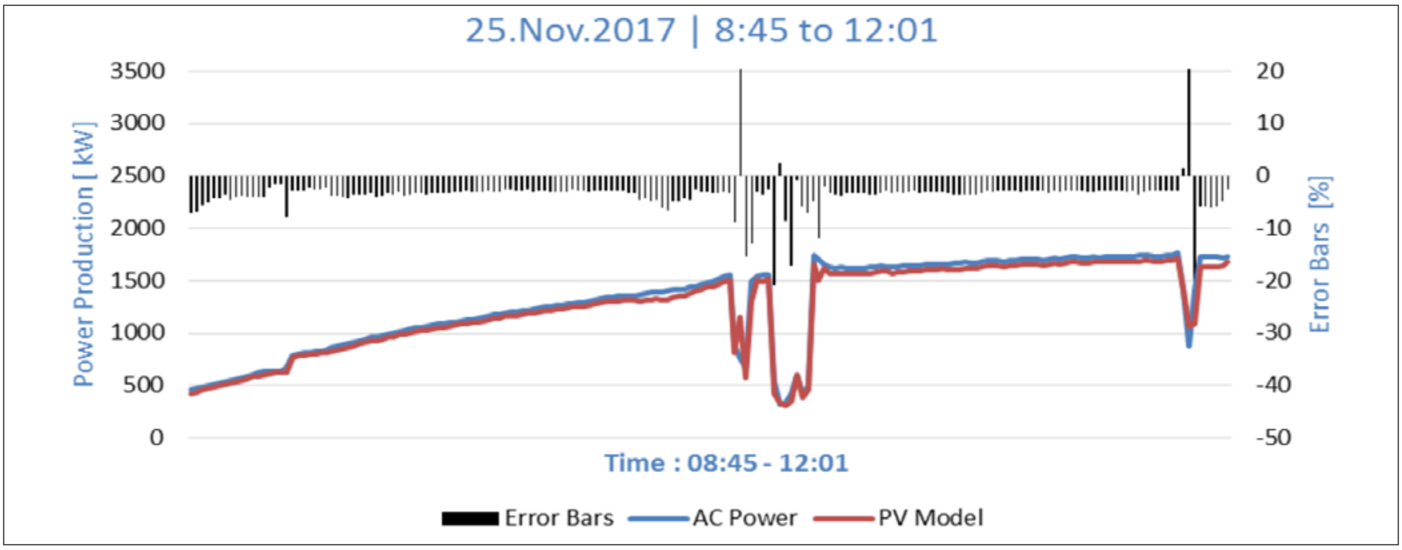

Figure 35: PV model accuracy: Accuracy of the Rainbows solar PV farm output (morning time), calculated by the PV model vs. the actual measured solar PV farm output

inverters was not consistent due to the MODBUS communications channel being shared with other parties. This meant the response times of the plant is non-deterministic and could not be guaranteed.

Hybrid solar PV and battery

With the addition of a battery storage unit, the hybrid system can achieve substantially faster response reaction times. These were found to

- have an average of 220ms until full response after receiving data from the LC
- have a fastest response time of 120ms
- have a worst case response time of 360ms.

Figure 36 below shows a comparison between the battery and solar PV reaction times.

The battery storage unit's faster response time provides an opportunity to optimise the hybrid system control strategy. A possible control strategy is shown in Table 13. It would also be possible to use the battery to increase the overall speed of response from the plant, then allow the

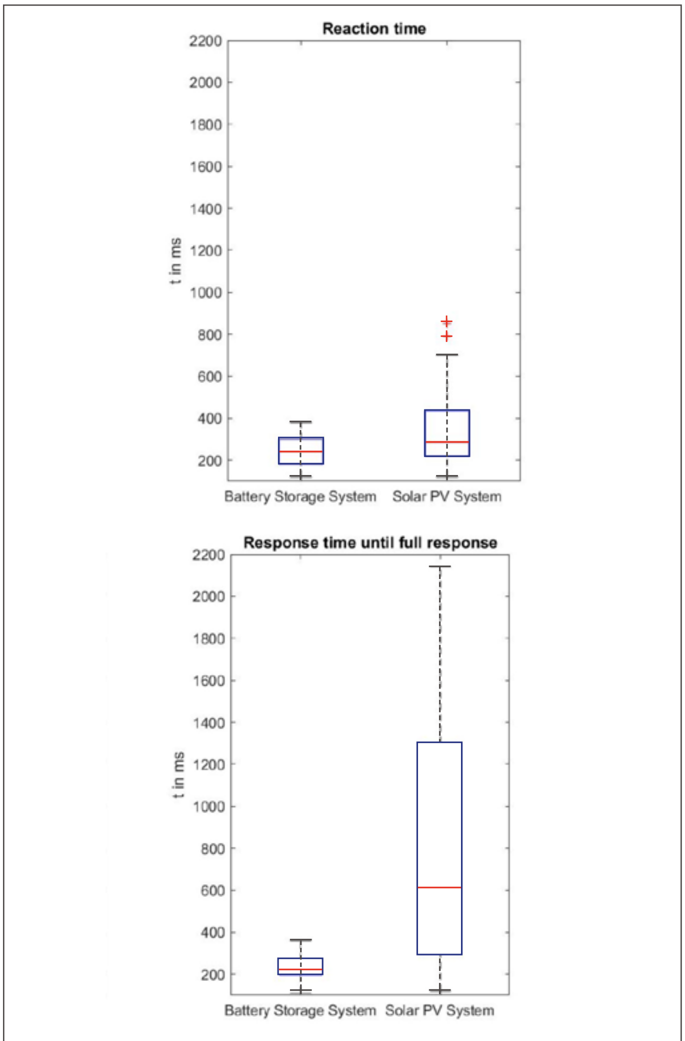

Figure 36: Reaction and response time analysis of the individual hybrid resources battery and solar PV system logged during the hardware in the loop test series.

solar PV to supplement the response in longer timescales.

This would be a useful consideration when optimising and coordinating the overall frequency response for the electricity network.

Conclusions

Frequency response	Night	Day
Under frequency response	Positive response: Battery	Positive response: Battery
Over frequency response	Negative response: Battery	Negative response: Battery + solar

Table 13: Potential day and night use of the hybrid system for under and over frequency response

The tests showed that a solar PV-battery hybrid system can be successfully integrated with the MCS. The battery can provide additional value for faster overall response and increases the overall system availability in comparison to a stand-alone solar PV system.

For the standard 2014 central converter-based solar PV farm, a fast reaction time was not considered during the design. The communication topology inside the solar PV farm was never meant to be fast, so retrofitting with a good network design and fast switches is necessary to provide frequency response.

While each large scale (central inverter-based) solar PV plant is different, the majority would face similar issues in providing a fast frequency response service. The response time of the inverters and potential delays in the communication setup will be main factors. In addition, solar PV inverter ramp rates may also be different but will generally be rather slow as the early generation of these inverters were not built to be fast. These inverters were installed to be very resistant and stable against oscillations inside a solar PV farm. However, retrofitting these plants is an option, as well as incorporating the project learnings into designing new solar PV.

A fast communication infrastructure is a key factor in the provision of fast frequency response. One of the restrictions at Rainbows solar PV farm is the MODBUS TCP/IP connection from the BELECTRIC hybrid controller to the inverters. The communication setup was designed as a 1:N connection bus with multiple clients participating, reading and writing simultaneously. As MODBUS TCP isn't deterministic the response times differ and cannot be defined as a fixed value. MODBUS TCP is not predictable with several devices and clients connected to the same communication bus and therefore non-deterministic. During the trials, delays of up to 13 seconds were recorded and response times were reduced by improving the plant controlling mechanisms. Improving the response time can be done by reducing the MODBUS TCP 1:N connections to 1:1 connections. Since there is only one device connected to the switch port, there is no possibility of data conflicts with multiple clients. A good network design with fast switches, and bridges where necessary, would raise the determinism of the network and reduce the communication delay.

Another response delay in the MODBUS connection occurs because of the TCP protocol. TCP delivers a reliable, ordered, and error-checked stream of bytes between the devices running on hosts communicating by an IP network. As TCP requires a 'hand shake' between sender and receiver, it checks if all data packages sent are fully received which takes extra time. UDP protocols may be more effective in this case, as the protocol does not require sender/receiver handshakes, however it has other limitations.

For the provision of power and the reliability of solar PV for frequency response, a forecast of the power capability is essential. The forecasting accuracy varies widely for the different methods of forecast, the duration and size of data samples that are used. The cloud movement camera initially used in the trial did not provide reliable and fast information, indicating the technology is not yet mature enough for this application. As a replacement a statistical forecasting method was developed during the project where the 15 minute forecast with large data samples had an accuracy of up to 95%.

With minimum effort, a negative response can be realised with a solar PV system, provided only slow response is required. Positive response is relatively costly due to curtailment and may require a change to the relevant renewable incentive mechanisms for this to be attractive to asset operators. In the case of solar PV plus battery hybrid systems, this limitation can be overcome and the use rate for response increased, so such combinations are recommended.

Battery storage can successfully support large scale solar PV systems in the provision of system services on transmission system operator (TSO) and distribution network operator (DNO) levels, where the battery may provide the fast reaction part of the response and night time availability, and could also aid in the provision of other services and may improve the usage of the PV farm connection to the grid as well.

Wind

Live tests at Burbo Bank wind farm showed that the existing plant can take part in the frequency support market with a faster and higher proportional response compared to existing Grid Code requirements.

A capability, described by Ørsted and Siemens Gamesa Renewable Energy (SGRE) as inertial response (IR), provides a way of increasing a wind power plant's active power generation by approximately 10% for 5-10 seconds without prior curtailment of the wind farm output. However, there is a wind speed-dependent associated recovery period, i.e. high wind speeds mean a low recovery period. The analysis has demonstrated a possibility for wind power to take part in a fast, coordinated frequency response service. The cost of testing IR in the field is quite high and it is not possible to control the wind conditions. Instead, simulations of the functionality were performed, as it made it possible to quickly generate new results and understand the impact of different parameter settings.

The following sub-sections detail a selection of the Burbo Bank wind farm test results and the IR work. All test results for Burbo Bank can be found in the '*Enhanced Frequency Control Capability (EFCC) Wind Package Report*' and the IR analysis in the '*System Studies for Demonstrating the Capability of Inertia Response (IR) from Windfarms Final Report*' both of which are on the project website.

Key findings

- SGRE 3.6MW turbines used on existing wind farms have the capability to be used for faster frequency response than is currently mandated in the Grid Code. An assessment of the turbines' mechanical structure showed there would be no detrimental impact if they were used for fast frequency response.

- SGRE testing and simulations of wind IR showed the capability of 7MW turbines to contribute to fast frequency response.

- Applying the SGRE wind IR capability and statistical analysis to Ørsted's portfolio of wind farms has shown there is potential for between 0% - 5% of additional power for use in frequency response. However, integration of this capability into an overall system frequency response needs to be predictable and coordinated with other response services because of the energy recovery period needed for the turbine rotors.

Burbo Bank wind farm tests

These tests aimed to demonstrate existing wind power frequency support capabilities. Burbo Bank comprises 25 SGRE turbines with a nameplate capacity of 3.6MW, totalling 90MW. The SGRE 3.6MW turbine has a mechanical structural safety limit that imposes an active power ramp rate limit of 20% of rated capacity per second. A full transition from rated production to zero would take approximately five seconds from command acknowledgement.

Tests parameters were selected to represent a broad spectrum of possibilities and show different dead bands, droops and the effect of a fall in wind speed. To show upwards regulation, the wind power plant was restricted to around 33% of rated capacity and tests were executed with an active power set point of 30MW and, with 24 turbines connected to the grid, a total capacity of 86.4MW.

Test results

Table 14 highlights two of the Burbo Bank tests showing a faster droop setting and maximum mechanical ramp rate. Results for all the tests carried out are described in the '*Enhanced Frequency Control Capability (EFCC) Wind Package Report*' that is published on the project website.

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Test number	Mode	Droop (%)	Deadband (Hz)	Frequency injection (Hz)	Description of the test
3	FSM	1.0000	0.015	-	Faster acting response based on a smaller droop and narrow dead band
9	N/A	N/A	N/A	0MW	Curtailment from full production to 0MW with a large enough droop to be limited by the turbine mechanical ramp rate (20% per second)

Table 14: Selection of Burbo Bank wind farm tests

- **Test 3**
  This test set a turbine droop characteristic of 1% and a deadband of 0.01Hz. The active power control system aligns accurately with the desired response and shows fast acting performance.

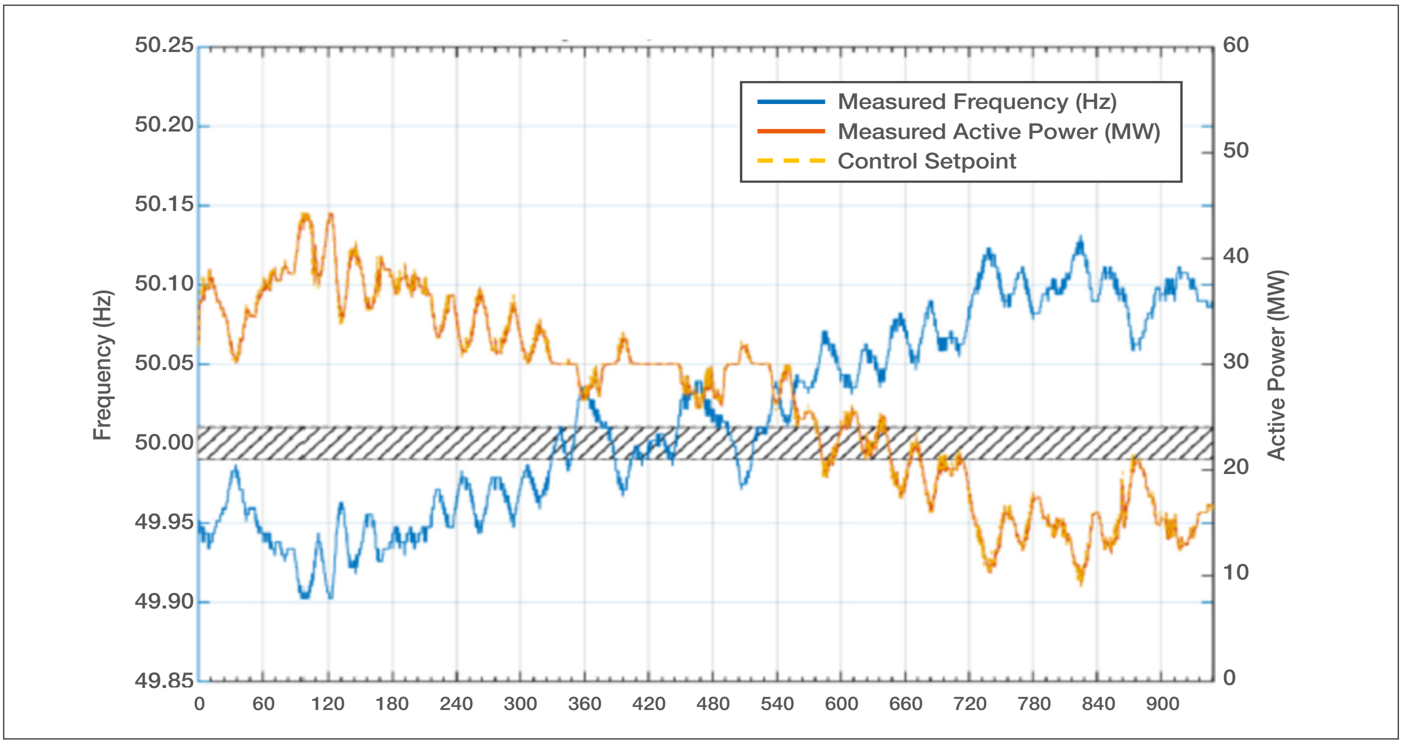

Figure 37: Burbo Bank faster response (test 3)

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- Test 9
  This test shows the wind turbines' maximum possible ramp rate within their existing mechanical limits. Each green dot in Figure 38 represents a one second sampling; it takes just under five seconds to get to zero production. The time required to complete the reduction aligns with the turbine ramp limit of 20% per second.

Figure 38: Burbo Bank ramp rate limit (test 9)

Conclusion

All the Burbo Bank tests have proved that current generations of wind power plants already have specific frequency response capabilities. The tests verify that the turbines can support the deadband and droop specifications needed to take part in fast frequency response. In particular, test nine illustrates the active power ramp of 20%, and the wind farm's central controller is fast enough for the plant to have a sub-second response. All the tests were carried out in Frequency Sensitive Mode (FSM) instead of a RoCoF trigger; as described in Chapter 6 (Required modifications to the planned approach).

Wind turbine inertial response

SGRE carried out a series of trials at different wind speeds on a SWT-7.0-154 (7MW) test wind turbine. The results were grouped into four pre-test power ranges relative to the rated power of the turbine:
- 20 to 40 %
- 40 to 60 %
- 60 to 80 %
- 80 to 100 %.

The resulting increase in active power output, time to reach maximum power output and the average active power output were recorded with different desired inertial response magnitudes relative to pre-activation power output:
- 5%
- 8%
- 10%.

Initially, the desired length of the IR was kept constant at 10 seconds to allow time for other sources of frequency support to activate. However, additional simulations were carried out with the IR kept constant at five seconds and the ramp downwards of the profile modified. This ramp down characteristic is used to mitigate how quickly the wind turbines lose energy. By having two sets of IR profiles it was possible to compare their effects.

There are few general tendencies that can be concluded from the IR response profiles produced. This is probably due to the fact that IR is highly dependent on the wind conditions and the number of simulations done. However, some conclusions can be drawn from the analysis:
- if the wind speed is increasing right before the IR injection period, the desired response is going to reach a higher peak in a shorter time
- if the wind speed is increasing during the IR injection period, the desired response is going to be sustained throughout the period, or even exceeded
- the higher the rotor speed, the more likely it is that the desired response is obtained
- in some circumstances, the energy lost during the recovery can be much higher than energy delivered during IR for a single turbine, though this is expected to be less pronounced at an aggregate level across many turbines in a large wind power plant.

Energy lost in the recovery period due to triggering IR was not quantified as part of the SGRE analysis and would require a prediction of the possible output power if there was no IR activation. Instead, the University of Strathclyde investigated the impact of the IR response on the operation of the electricity transmission system; this analysis is described later in this section of the report.

Portfolio analysis

Ørsted carried out a portfolio-wide assessment using the response profiles provided by SGRE and historical wind data to give an indication of the magnitude of the IR response across a fleet of windfarms.

The SGRE IR profile results were divided into groups (as shown in Table 15) by current production as a percentage of rated power, and a general turbine profile created from the average response for each group to give an assumed generic IR profile.

Active power group	IR magnitude %
0-20%	0
20-40%	6.95
40-60%	7.60
60-80%	8.36
80-100%	4.35

Table 15: Assumed generic turbine IR profile

The IR magnitude percentage shows the increase in active power proportional to the pre-activation generation level and can start delivering a significant injection of energy into the grid within 250ms. It should be noted that the numbers in Table 15 are used as a general response profile for SGRE turbines and different turbine types could show different IR performances.

In carrying out the portfolio analysis, a number of assumptions were made:
- energy lost in the recovery period is not considered
- energy lost due to ramp up time is not considered
- energy gained as part of the ramp down period is not considered
- average additional power is sustained throughout the entire IR period
- SGRE turbines of different models show similar IR performance.

As wind power is a stochastic resource, the key interest from a system stability perspective is certainty about delivery of the offered response service. The desired curve is a combined IR active power probability distribution.

The calendar year 2016 was chosen for wind power site data because the data history was complete so a probability distribution for the amount of IR could be developed. Key probability figures are shown in Table 16.

IR injection magnitude relative to portfolio capacity	Probability
1%	68 %
2%	50 %
3%	35 %
4%	17 %

Table 16: IR injection magnitude probabilities

System analysis of the capabilities of inertial response from wind farms

The University of Strathclyde studied the impact of IR activation time and the capacity and location of the wind farms, providing IR on their effectiveness in supporting frequency control using the 36-bus reduced model of the NETS in DIgSILENT PowerFactory.

The following areas were investigated in the simulations.

- Comparison of conservative and mean profiles: this is to investigate the differences and the associated impact on frequency support effectiveness between the conservative and mean IR profiles from SGRE. The conservative profile represents the IR from the 90% percentile of the number of simulations taken and the mean profile represents the average (50%) of the simulation data.
- Impact of IR activation time: this is to investigate how the activation time (ranging from 500ms to 1000ms) following a frequency event impacts frequency control and containment.
- Impact of wind farm loading and capacity: this is to investigate the effects of the wind farms' various rated power loadings. It also investigates the suitability of SGRE wind farm capacity for a range of loading levels in order to contain the frequency degradation to 49.5 Hz during loss-of-infeed events.
- Impact of location of the wind farms providing the IR: this is to investigate the locational impact of windfarms' IR on frequency restoration.

The following default settings were applied unless otherwise specified.

- Activation time of IR is 500ms delay after the event (except for the activation time investigation studies).
- Capacity of SGRE wind farm generator(s) is 2 GVA (except for the capacity investigation studies).
- SGRE wind farm generator is loaded with conservative profile at 20%-30% of rated power (except for the loading investigation studies).
- SGRE wind farm generator is activated in the south west (except for the location investigation studies).
- A low frequency event is simulated by a generation loss of 1320MW

A selection of the analysis is shown here to indicate the

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impact of using wind turbine IR from a system perspective. Full results are detailed in the '*System Studies for Demonstrating the Capability of Inertia Response (IR) from Windfarms Final Report*' published on the project website.

Comparison of conservative and mean profiles
SGRE provided two sets of IR turbine profiles (mean and conservative). The mean value represents an average inertial response expected at different loading levels. The conservative profile represents the inertial response from the 90% percentile of the number of simulations taken; this increases the likelihood that more turbines will provide lower IR response at the same loading level. Due to the turbine recovery period, and with no other response services used, both conservative and mean profiles show there was the risk of a second frequency dip occurring. By comparing the size and time of the system frequency dips when the mean and conservative profiles applied, the mean profile gives a smaller power drop after the IR.

Analysis across all the IR profile loading points showed that:
- the recovery time after the frequency event is similar with mean and conservative profiles
- the second frequency drop is more severe as the loading level of the turbines increases
- the time at which the second frequency drop occurs is later as the loading levels of the turbines increase.

Impact of IR activation time
In this analysis, the IR response is triggered at either 500ms or 1000ms after the system frequency event to see how the frequency deviates and the impact on conventional generation governor response.

Figures 39(a) and 39(b) show the impact on system frequency using the five second IR duration with slow ramp down profiles with activation time.

Overall, both 500ms and 1000ms activation times minimise the system frequency nadir, and the 1000ms activation causes the second frequency drop to occur slightly later. A 500ms activation time shows the energy recovery period to be reduced compared to 1000ms.

There was no significant difference between the two activation times in terms of their effectiveness on frequency containment. Further analysis is required to fully explore the effectiveness of activation times for a wider range of network conditions.

Impact of wind farm loading and capacity
This analysis considered the impact of the capacity of the wind farms providing IR at different capacity levels on the effectiveness for frequency support. The aim was to find the optimal capacity of the wind farms providing IR to contain all frequency deviations to 49.5Hz or above. In summary, the results showed:
- for 10s IR duration, as the wind farm capacity increases, it can introduce a negative effect on the second frequency drop, so to maintain frequency above 49.5Hz the energy recovery needs to be limited. This limits the wind farm loading to 50% with a maximum total wind farm capacity of 2GVA to 3GVA that have IR enabled
- for 5s duration with slow ramp down, this gives significantly improved frequency support capability as it was possible to maintain frequency at or above 49.5Hz for loading levels up to 100%. The total capacity of wind farms with IR that can be managed is around 3GVA to 5GVA

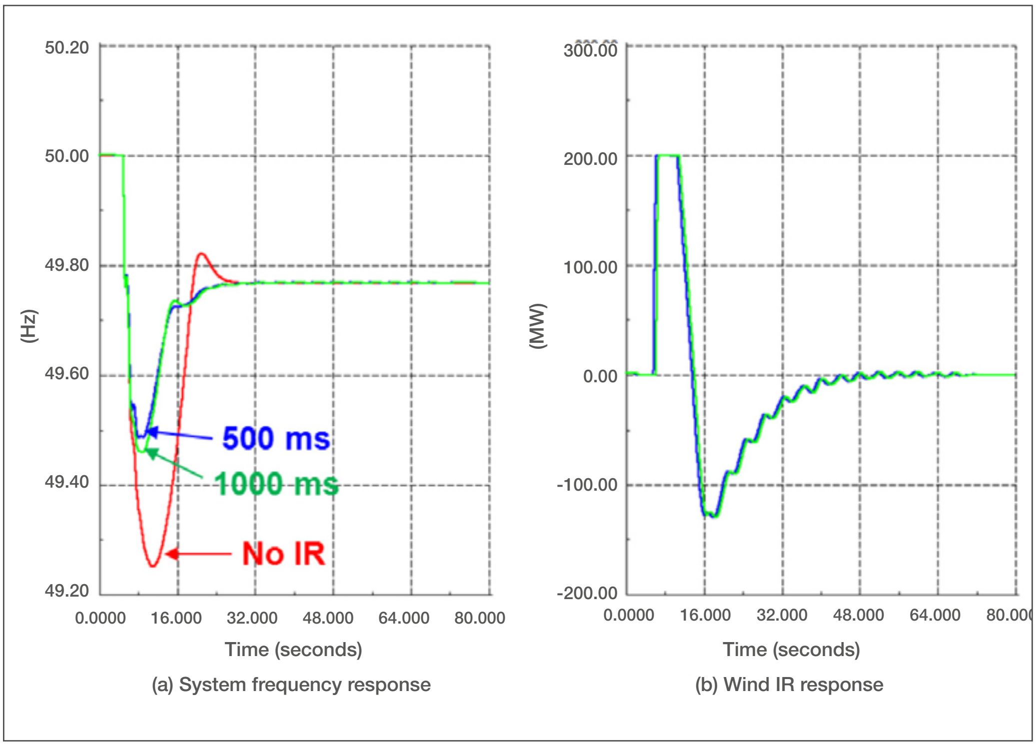

Figure 39: SGRE wind response (5s mean profile, 20-30% loading of rated power, 2 GVA)

Impact of location of the windfarms providing IR
In this study, the wind farm providing IR is located in different parts of the network to evaluate the locational impact on the system frequency. Both conservative and mean IR profiles were used for wind farms in the south west, middle and north zones of the 36-bus model that represent the equivalent areas of the NETS.

By evaluating the frequency profiles across various parts of the network after a frequency event was simulated, it was found that the location of the IR from wind farms does not have a significant impact on how much the frequency deviates.

Conclusion
From a National Grid Electricity System Operator (NGESO) perspective, IR response from wind farms has the potential to support fast frequency control, as both the 10s and 5s profiles contribute to containing frequency in fast timescales. However, careful consideration needs to be given to the prior loading point of the wind farms before IR is initiated, as well as the potential amount of IR available, as this can impact the turbines' energy recovery period. The recovery period needs to be predicted by the MCS and back-filled by other service providers. Any additional time needed for other service providers to either ramp up or down and the volume of their response needed to cover this period also needs to be calculated. This reinforces the fact that the energy recovery needs close coordination with other response services to maintain frequency within operational parameters.

Triggering the IR at either 500ms or 1000ms after the system event does not appear to worsen the frequency deviations. In practice wind farms will not have a uniform IR activation time and the analysis showed that this would not be detrimental to managing frequency containment.

The studies with the 5s IR duration with slow ramp down profile show that it is more beneficial to overall frequency response as the energy recovery period was minimised and increases the capacity of wind farms with IR that can be managed on the NETS. The slow ramp down characteristic SGRE has employed after the inertial response is triggered mitigates against a steep energy drop-off such that a second fall in system frequency was not as severe compared to the 10s IR duration response.

IR has also been considered against the effect of a fault disconnecting generation. Analysis considered how much IR response would see a voltage <0.9p.u during the period of the fault. The analysis noted that this dip impacts large proportions of potential available IR response. While the voltage recovers quickly following the clearance of the fault, further work is required by SGRE to determine the control enhancements which would allow the wind farm to ride through the fault and, upon fault clearance, provide IR.

It is important to note that the control approach used by SGRE can be modified for different IR durations, and further work needs to be conducted to develop an approach for quantifying the system requirements for a wider variety of inertia levels and operating conditions.

Impact assessment of the MCS on operational systems

An assessment was completed of the systems that would be impacted within NGESO if the MCS was implemented within business as usual activities. The technical solution developed by GE Renewable Energy was also analysed to understand how it would work within the energy industry.

Key findings
- Several business systems would be impacted by the implementation of the MCS. A detailed approach would be required to align any transition of the MCS into business as usual with other business improvement initiatives.
- Further consideration of critical operational aspects would be needed before any implementation of the MCS. These include PMU weighting, inertia calculations, interfaces to the control room and the settlements process.
- The current design of the MCS could require a significant volume of data transfer across the communication network, with information being shared between each LC and RA. The specific volume of data will be dependent on the number of PhasorControllers and the MCS roll-out strategy. Service providers are likely to be connected to the MCS via a combination of dedicated communication circuits and internet connectivity.
- Broadcast and multicast communication networks can be used. Both present challenges; broadcast transmission on how a virtual local area network can cover the whole of GB; multicast transmission on the provision of a secure data route.
- A cyber security vulnerability assessment of the PhasorControllers showed there are no major weaknesses to the control platform and supporting software. Recommendations were made to improve the configuration settings for encryption links.

Business process mapping

There are many information technology (IT) systems and business processes that would be impacted within the NGESO if the MCS was implemented. This not only includes the systems used by the control room to arm and disarm the response service, but also registration, contracts, response scheduling, settlements and billing systems.

Figure 40 shows the cross-functional business systems that would require modification for the operation of the MCS.

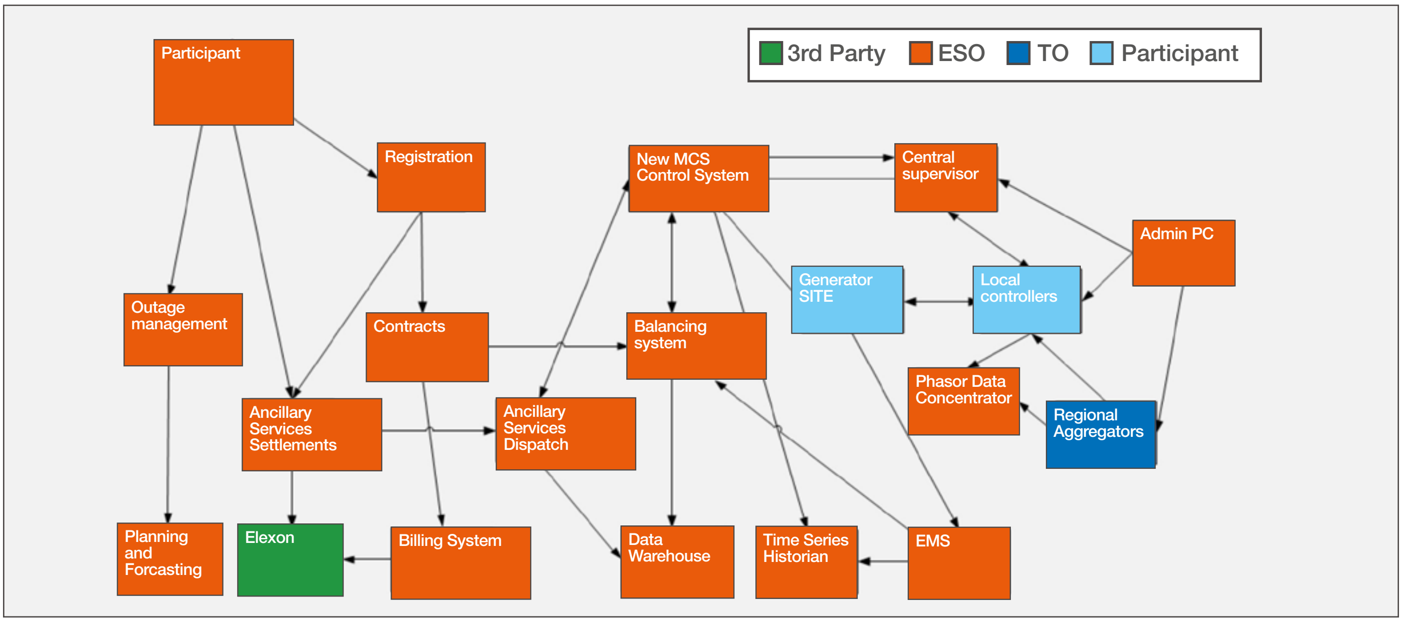

Figure 40: Interaction between ESO business systems and the MCS

The NGESO uses several IT systems to be able to use response from non-transmission connected generation. As the response connected to the MCS can come from transmission or distribution connected service providers, any implementation of the MCS needs to align with ongoing business initiatives to reduce barriers to entry for all providers and any IS platforms that are developed to facilitate access.

Further details of the business processes impacted are detailed in the '*System investigation and Business Impacts Report*' published on the project website.

Impact of the MCS design and settings

The following six areas of the MCS design were identified for further analysis to understand how operational and commercial decisions are made by the system.

- PMU weighting
  The way the PMU weighting calculation is derived needs to be defined and agreed across planning and operational teams, as this parameter is dependent on the generation profile and the topology of the NETS. Also, how the MCS gets system data (such as regional inertia measurement) to support this calculation needs investigating.

- System inertia calculation
  The MCS requires an inertia calculation to perform the optimisation and dispatch algorithms. It needs to be verified that the existing inertia calculations produced by several IT systems are of sufficient quality and frequency to define a suitable level of accuracy and confidence to use in the MCS. Projects are currently being taken forward by the NGESO to find a more accurate method of calculating system inertia.

- Operational kill-switch and control room visibility
  Further development work is required to include a mechanism that will allow the control engineers to stop (disarm) the MCS in normal and emergency conditions, including suitable indications and alarms. The MCS output needs to be visible on control room screens to show how sites are responding. In addition, consideration must be given to how the control room can optimise the response connected to the MCS with other service providers to ensure there is enough overall response available on the NETS.

- Bad data detection
  Tests carried out by the University of Strathclyde have defined how the MCS handles poor quality data and its potential threshold settings. However, further investigation is required to understand how these settings can be applied to the MCS when it is installed on the network.

- Usability and database configuration
  Currently MCS configuration is done from a computer that could be in the control room. Processes need to be reviewed to understand if an alternative user interface should be put in place.

- Settlement and metering
  Further consideration needs to be given to metering and the settlement process. It is not clear if it is essential to receive sub-second operational metering from the MCS. Given the criticality of the MCS in delivering sub-second frequency response, sub-second settlement metering may be required to verify if a participant is compliant with their contracted position. Receiving sub-second operational metering from a lot of sites would place a significant burden on energy management systems. However, the amount of data produced would enable the NGESO to provide reports on which sites are being selected by the MCS, allowing for market transparency.

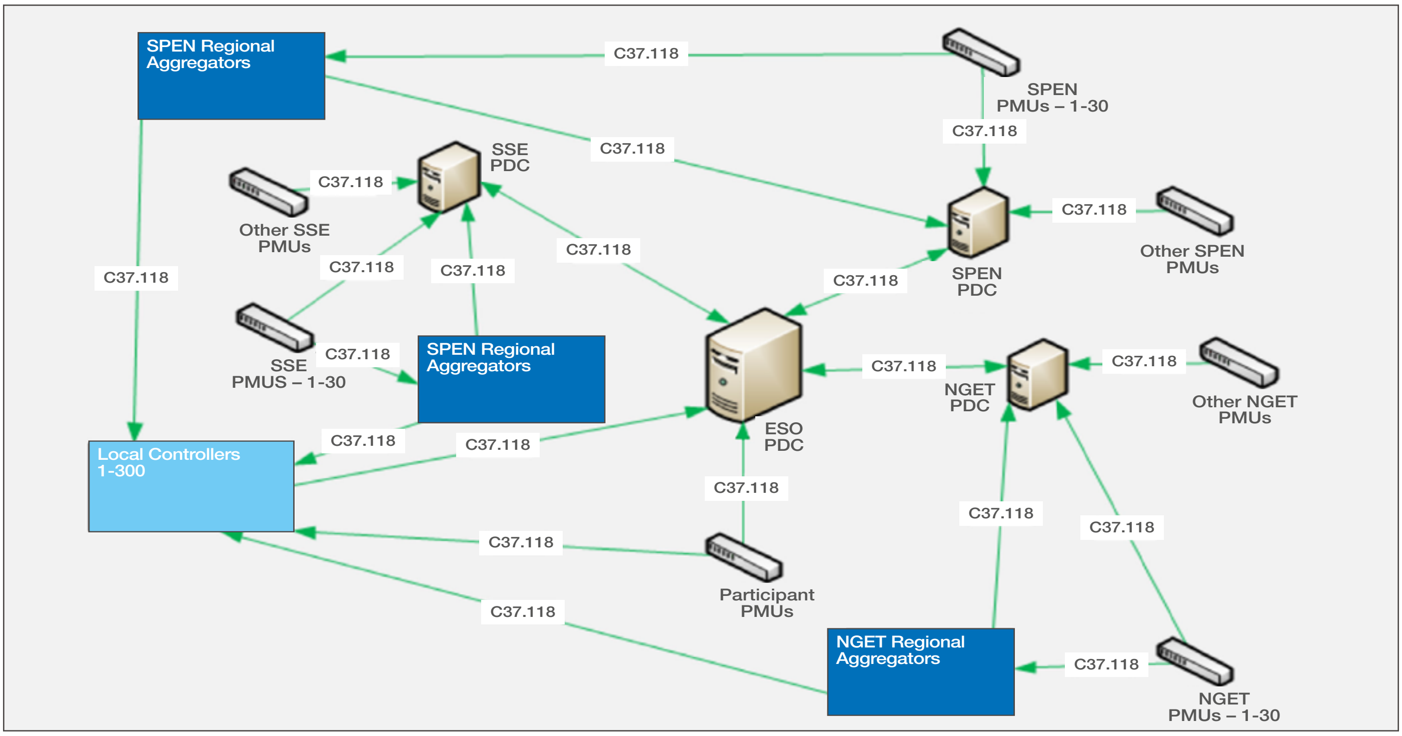

Figure 41: PMU and PhasorController C37.118 data streams across the network

Wide area networking
The MCS transmits a significant volume of data. Individually the data transmitted between each component is not huge, however once the number of PhasorControllers that make up the system increases in size, there is a significant increase in the amount of data traffic. This is perpetuated predominantly by the C37.118 data streams. Figure 41 shows the potential interaction of C37.118 data across the network.

At the very heart of the MCS is speed and resilience. To achieve this, most of the complex algorithms in the MCS have been placed at the edge of the scheme within the LC. Figure 42 shows the data flows between PMUs and the MCS and highlights that every RA must send an aggregated C37.118 feed to every LC. As an example, 12 RAs would send 550 kbps of C37.118 data to each LC.

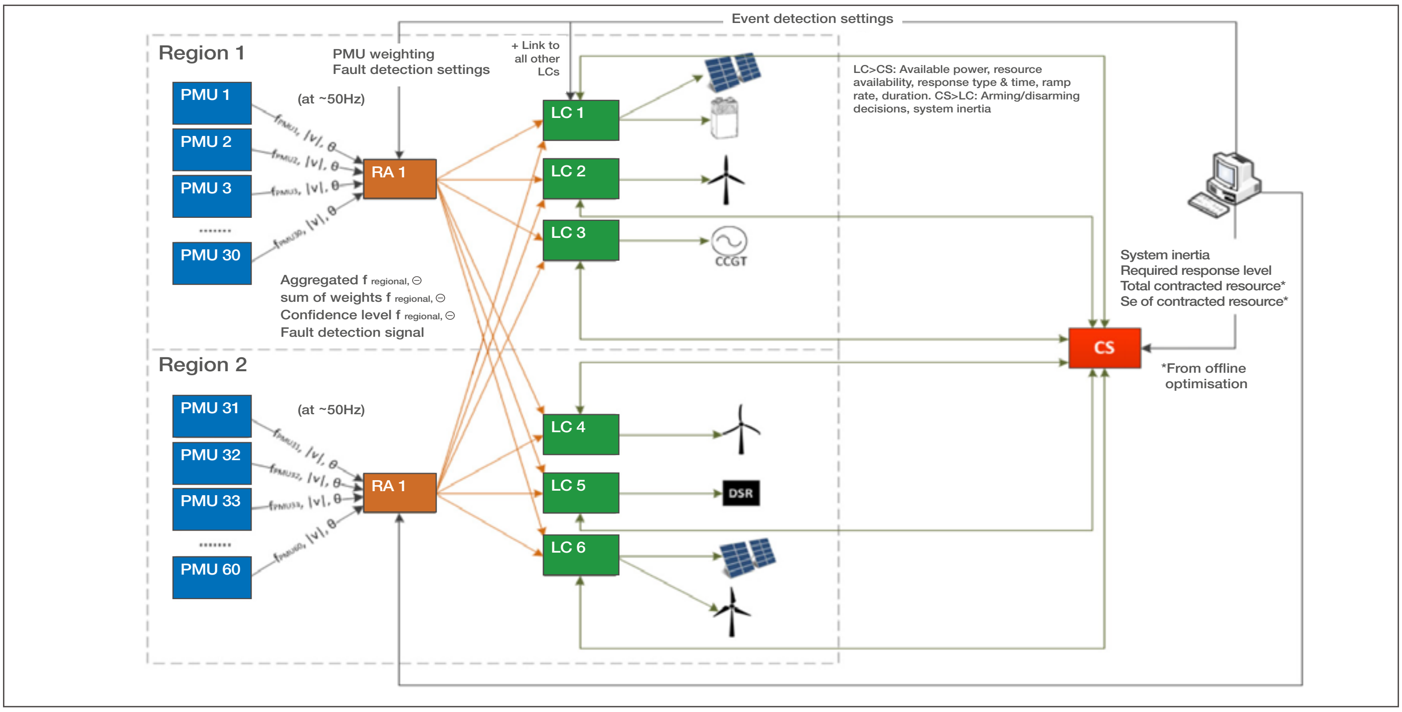

Figure 42: Data flows across indicative regions of the network

If the IEC 61850 MMS data traffic between the LC and the CS is not optimised, and the administration traffic to allow changes to the settings of the MCS is factored in, it may be necessary to have a network connection that supports 1Mbps for each of the LCs. There is the potential for data traffic to exceed 250GB per month for one LC. At the RA level, data traffic could soon increase as the number of LCs increases. The RA data traffic could be reduced if broadcast or multicast communication network principles were used. Broadcast transmission is where data is transmitted from a single source to multiple parties; there is only one component sending data. Whereas multicast transmission is where data transmission is sent simultaneously and there may be more than one component sending data.

The use of broadcast transmission would imply there is a single broadcast domain and generally one virtual local area network (VLAN) that would have to stretch across the electricity network. Multicast could be used, but that would mean that every router on the network would need to be part of the multicast group, implying that a single party would need to own and control all the routers involved.

There is additional complexity with the potential mix of critical national infrastructure (CNI) categorised sites and smaller sites that are within the distribution network that only receive mobile networks. Currently the only effective method to allow large transmission connected BMUs and embedded generators within the distribution network to connect to the MCS is to combine a fast control network and internet access. However, there are several challenges with this method.

- Security: ensuring internet traffic cannot accidentally or maliciously cross into the control network used for operational control of sites. At a substation level, each one will need a secure gateway that allows internet communication and communication over the control network.
- Performance: users on the internet would have increased latency and lower connection reliability than generators on the control network.
- Data plans: given that the LC could be receiving and sending between 150GB and 250GB of data per month, a robust and well negotiated data plan will need to be in place. Mobile broadband plans could be precluded by this data volume, so physical networks may be necessary.

Depending on the precise uptake and mix of service providers, the amount of data traffic needs to be fully evaluated.

Cyber security assessment of the MCS

As a prerequisite to any potential installation of the CS, RA and LC at substation sites, a cyber security vulnerability assessment was carried out to evaluate if it would be possible for someone to illegitimately access the MCS and change the input settings. This involved testing the PhasorController infrastructure (web server, secure sockets layer (SSL), encryption layer) and web application interfaces of the controllers to find any security issues with the configuration.

The assessment showed there are no major weaknesses in the control platform and supporting software, and recommended configuration settings for encryption links to ensure data integrity were completed.

Conclusions

Many systems have been identified which could be impacted by the MCS and a more detailed approach is needed to align the balancing or ancillary services systems to resolve any potential conflicts. These considerations are discussed further in Chapter 11 (Planned implementation).

The evaluation of the data flows and communications revealed significant volumes of data are needed to operate the MCS as currently designed. Scaling up the system on the communications network will need to be examined against potential roll-out strategies to incorporate new providers. A combination of a fast control network and internet connectivity is possible, though there could be challenges related to security, performance and data plans which would require further consideration.

Value of coordinated fast frequency control

The results from the cost benefit analysis (CBA) have confirmed that there are potential benefits in the introduction of a faster frequency (0.5 second) response service coordinated by the MCS (EFCC scenario). This could potentially unlock millions of pounds of savings a year by reducing the amount of market intervention required by NGESO to balance the electricity system.

Key findings

- CBA identified savings in both Steady State and Consumer Power Future Energy scenarios.
- Potentially unlocking millions of pounds of savings each year by reducing the amount of market intervention required by NGESO to balance the electricity system.
- Savings will be offset by the cost of implementing and maintaining the MCS.
- Accessing the potential significant benefits will require enhancements to the MCS and development of the appropriate commercial framework and IS interfaces.

The benefits of the EFCC scenario have been considered against the existing services (Primary, Secondary and Enhanced Frequency Response (EFR) and High)[3] and against different future energy scenarios (2017 Consumer Power and Steady State). The new frequency service products currently being developed by the NGESO with industry consultation have not formed part of the CBA. The assessment did consider and offset any potential savings with the cost of implementing and maintaining the MCS (three different roll-out approaches have been used).

[3] https://www.nationalgrideso.com/balancing-services/frequency-response-services

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The potential benefits are dependent on key factors which have a material impact on using the MCS in maintaining system frequency:

- topology of the electricity system (including RoCoF and maximum system loss)
- type and volume of generation connected to the electricity system as depicted by future energy scenarios
- number and location of service providers providing frequency response through the MCS
- interaction and exchange between the different frequency response services.

These factors combine differently within the Steady State and Consumer Power scenarios, providing a wide range of potential opportunity which may ultimately provide benefit to consumers. The CBA reaffirms the original project premise that the ability to coordinate faster acting frequency response has significant benefit, particularly in a low inertia system, as it enables the system frequency to be maintained with a higher penetration of non-synchronous generation, with a larger maximum loss, to be secured on the system. This makes it possible to both

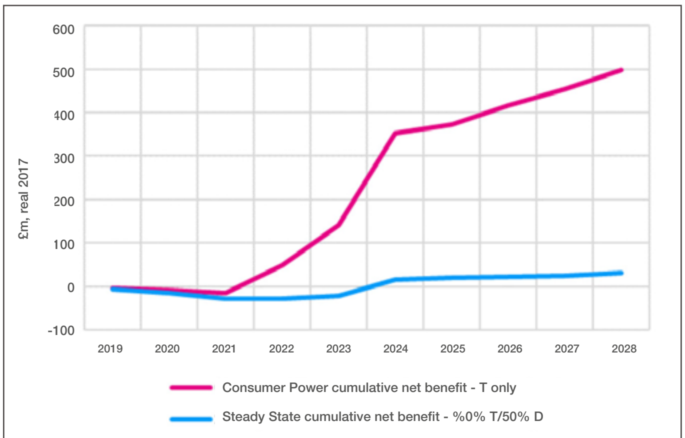


Figure 43: Cumulative net benefit of EFCC scenario

reduce market intervention for the provision of response as levels of non-synchronous generation fall, and increase market access to support those response requirements more flexibly than today. Figure 43 shows the potential range of benefits of the fast, coordinated response provided by the MCS.

Unlocking potential benefits

Accessing the potential benefits will require enhancements to the MCS (to increase its technology readiness) and a phased approach to its implementation. Development of the appropriate commercial framework and IS interfaces to enable the scheme to operate will also be required. Further information is available in Chapter 11 (Planned implementation).

The new frequency response services currently being developed by NGESO in consultation with the industry can be used by the MCS, as its control system functions can be modified to incorporate the technical requirements of the new services.

Performance compared to original project aims, objectives and SDRC deliverables

Table 17 summaries the key objectives from each work package (WP) and how the project performed against its SDRC deliverables.

Work package	Partner	Business case objectives	Outcomes
WP1 Developing and testing the monitoring and control system (MCS)	GE Renewable Energy	Develop an innovative MCS to measure regional frequency, system angle and rate of change of frequency (RoCoF) to inform a proportionate response with regional prioritisation.	This has been achieved and validated in laboratory and field trials where the MCS successfully worked with different types of generation and load technologies with an ability to change power or trip.
WP2 Assessment of the response of different providers			
WP2.1 DSR	Flexitricity	Develop and demonstrate the operation of real industrial and commercial aggregated demand side response (DSR) resources to support system inertia in a variety of categories, potentially including: • RoCoF control – DSR assets providing rapid deloading to the network in response to signals corresponding to a high rate of frequency change • simulated/synthetic inertia – assets providing autonomous increases and decreases in consumption using variable speed drives comparable to real inertia • real inertia – synchronising additional small generation and load at times of low demand to provide system inertia in an aggregated form.	This has been achieved with live trials on six customer sites across three different categories, generating enough data to measure performance and evaluate each DSR service type.

WP2.2 Large-scale generation	Centrica/EPH	Demonstrate that large-scale generation combined cycle gas turbines (CCGTs) can respond to a RoCoF input signal.	This has been achieved by modifying the control loop of the CCGT plant to respond to RoCoF.
WP2.3 PV power plant	BELECTRIC	• Demonstrate a reduction in output power in accordance with frequency changes and/or by direct communication with National Grid Electricity System Operator (NGESO). • Demonstrate a positive frequency response by operating the power plant below MPP (maximum power point) to reserve the head room created for frequency response provision. • Demonstrate the provision of reactive power for voltage stabilisation control.	Reducing power output in line with frequency, and operating the power plant below MPP, have both been demonstrated. However, the long latency times of the communication network limits voltage stabilisation and requires further investigation.
WP2.5 Wind	Ørsted & Siemens Gamesa Renewables Energy (SGRE)	Demonstrate that a large, multi-turbine wind farm can respond to a RoCoF input and/or an external control signal.	Due to changes in project partners, an alternative approach was agreed which involved exploring the response capability of Burbo Bank wind farm beyond Grid Code requirements. In addition, inertial response from the 7MW test turbine in Øesterild, Denmark, was tested and analysed to show the impact of this response on the transmission network.
WP3 Optimisation	University of Manchester	• Understand how the selected resources can be coordinated to provide optimised response. • Understand the communication infrastructure necessary to support the proposed supervisory control strategy from a latency and bandwidth requirements perspective.	The technical capabilities of the different service providers (which form part of work package 2) have been modelled to understand their frequency response behaviour. Additional time was spent on analysis to understand the impact of the MCS on the electricity transmission system and the interaction between existing frequency response services. The project team determined that latency and bandwidth requirements for the control scheme would be better identified through field trials and RTDS (real time digital simulator) studies (please refer to WP4).

WP4 Validation	University of Manchester and University of Strathclyde	• Convert the proposed new monitoring and control scheme into a flexible hardware-in-the-loop environment, allowing testing and a performance assessment of the MCS. The scheme will be simulated using software for RTDS testing, and tested at the Power Networks Demonstration Centre (PNDC). • Assist with de-risking solutions and provide detailed information about the performance of individual controllers and wide area monitoring and control schemes. • Identify any in-service issues and remedy before moving to wider roll-out. • Universities' resource to be used for the dissemination and demonstration of the MCS.	This has been achieved. The testing programme identified a few issues with operating the MCS which GE Renewable Energy resolved. Additional understanding of the performance of the MCS, in terms of communication interfaces, data measurement and sampling was also obtained. The project learning has been disseminated at various events and through research papers (submitted and subsequently published).
WP6 Commercial	NGESO, GE Renewable Energy, University of Manchester	Create a new balancing service allowing immediate roll-out of the enhanced frequency control capability and achieving the savings envisaged on frequency response costs.	NGESO decided it would not be appropriate to progress with the development of a standalone EFCC balancing service product.
WP7 Communications	NGESO	Ensure technical aspects relating to the roll-out of the EFCC are considered in a separate work package but in parallel with commercial developments.	Potential interfaces of balancing service systems have been identified. Further work would be required on the technical (including compliance requirement) aspects if the MCS is implemented.

Table 17a: Key objectives for each work package

Table 17b below shows the SDRC, the evidence provided and whether it was achieved.

Successful delivery reward criterion (SDRC)	Evidence	Owner	Status	Comments
Formal contract signed by all partners	Formal contract of EFCC signed by all partners	National Grid ESO	ACHIEVED	Delayed by six months because of challenges around intellectual property.
	Flexitricity to have agreements in place with DSR customers	Flexitricity	ACHIEVED	Both the collaboration agreement between the partners and the relevant commercial contracts between Flexitricity and participating sites were signed with enough time for successful deployment and testing. Delayed six months from original date.
Monitoring and control system developed successfully	Application development: event detection algorithm completed	GE Renewable Energy	ACHIEVED	Event detection specification report (delivered 30 April 2015).
	Application development: EFCC resource allocation algorithm completed	GE Renewable Energy	ACHIEVED	Design report for resource allocation (delivered 31 August 2015).
	Application development: optimisation algorithm completed	GE Renewable Energy	ACHIEVED	Design report for optimisation (delivered 29 January 2016).
	Application development: testing completed	GE Renewable Energy	ACHIEVED	Test report from applications testing (delivered 29 April 2016).
	Application development: revision completed	GE Renewable Energy	ACHIEVED	Report covering applications revisions (delivered 24 March 2017).
	Control platform development: specification completed	GE Renewable Energy	ACHIEVED	Summary of control platform specification report (delivered 30 April 2015).
	Control platform development: development completed	GE Renewable Energy	ACHIEVED	Report describing the control platform development (delivered 29 April 2016).

	Control platform development: controller testing completed	GE Renewable Energy	ACHIEVED	Two reports on test results provided: 1. Intermediate report (delivered 31 August 2016) 2. Final report (delivered 30 September 2016). Testing of the MCS was not completed by August 2016 so GE Renewable Energy submitted an intermediary report. The change in the project from a centralised scheme to a distributed scheme increased the complexity and number of tests significantly: an extra four weeks was needed to complete the tests. Given the complexity of the scheme, GE Renewable Energy were unhappy to compromise on quality, which slightly delayed delivery of this SDRC.
	Control platform development: revision completed	GE Renewable Energy	ACHIEVED	Report covering revisions on the control platform (delivered 26 July 2017).
Storage decision point	Recommendation made to Ofgem	National Grid ESO / BELECTRIC	ACHIEVED	A report and recommendation was submitted to Ofgem in June 2015. Ofgem ruled in January 2016 not to fund this element of the project and all associated project costs for Work Package 4 should be returned to consumers. However, Ofgem said that they still believed battery storage could help maintain future system reliability. It was decided to seek additional Network Innovation Allowance (NIA) funding to cover the costs of leasing the BELECTRIC battery storage unit for the NIC EFCC trials instead of funding the cost of the battery itself.

Response analysis from service providers (reports detailing the result of the demonstration of the response from providers)	Demand side response	Flexitricity	ACHIEVED	Trials showed that the three DSR methods can deliver enhanced frequency control. It was delayed by installing GE Renewable Energy equipment at third party sites, with limited access to these sites for installation works and coordination with their business as usual activities. A full technical report is available on the project website.
	CCGT Power Stations	Centrica/EPH	ACHIEVED	Centrica/EPH demonstrated that a gas turbine could change load at the maximum permissible rate related to RoCoF rather than proportionally to frequency deviations. Centrica/EPH's technical report can be downloaded on the project website.
	PV Power Plant	BELECTRIC	ACHIEVED	For the stand-alone solar PV, experiments were conducted concerning power curtailment and power ramp-up in PV power plants in order to deliver frequency response. This was mainly done using existing hardware and required only minor hardware changes and the installation of communication cables. It was delayed because of interfacing with control system equipment and access to the thrid party site. A full technical report is available on the project website.
	Storage	BELECTRIC	ACHIEVED	This does not apply as the project scope changed. Please refer to SDRC – storage decision point.
	Wind farm	Ørsted & Siemens Gamesa Renewables Energy	ACHIEVED	Ørsted and SGRE triggered the inertial response directly from their control system. It was delayed because the project partner changed and there were challenges with accessing operational sites. A full technical report is available on the project website.
Successful validation of response	Successful delivery of representative models and validation of trial results using the models	National Grid ESO/ UoM / UoS	ACHIEVED	Realistic testbeds were established that allowed potential issues which were not anticipated during the MCS design stages to be identified and successfully addressed by working with GE Renewable Energy. It was delayed because modificaitons and upgrades to the MCS's firmware needed further testing.

New enhanced frequency response service developed successfully	Successful development of new enhanced frequency response service as part of new balancing services	National Grid ESO	Missed	In line with the 2017 System Needs and Product Strategy (SNAPS), National Grid ESO decided that it would not be appropriate to continue developing a standalone EFCC balancing service product. Since the bid submission, there have been significant changes to the energy landscape that affect system requirements and present operational challenges. This means the business is concentrating on developing a suite of new, faster acting frequency response products, taking the learning from EFCC, rather than developing a single EFCC product.
	Report with recommendations regarding implementation of the new service	National Grid ESO	Missed	
Successful knowledge dissemination	Knowledge sharing e-hub delivered	National Grid ESO	ACHIEVED	A dedicated project website and email address were created to allow direct contact with the team.
	All non-confidential data and models developed as part of EFCC to be shared on the e-hub	National Grid ESO	ACHIEVED	All documents produced have been published on the project's website and can be downloaded.
	Annual knowledge dissemination activity (at least one per year) organised	National Grid ESO	ACHIEVED	Dissemination activities have included stakeholder events, webinars, publications, exhibitons and presentations at other industry events.

Project close and knowledge dissemination	The control systems required as part of WP2 (developed by WP1) are demonstrated and validated	GE Renewable Energy, University of Manchester and University of Strathclyde	ACHIEVED	The local controller developed as part of the monitoring and control scheme was successfully demonstrated and validated, and shown to initiate a fast RoCoF based frequency response. Delays experienced due to interfacing with third party sites.
	The response capability of the type of services described in WP2 are trialled	Commerical partners	ACHIEVED	All technologies trialled, except solar, have proved that it is possible to achieve a faster frequency response. It was delayed because of access to third party sites and timing of frequency response incidents.
	The optimisation based on information gathered in WP2 is carried out	University of Manchester	Missed	When the project approach was refined, this task was superceeded by additional simulations that showed the need for wide area control schemes and identified the best way to implement these schemes.
	Validation exercise of WP1, WP2 and WP3 is carried out as well as further tests in PNDC to mitigate the identified risks	GE Renewable Energy, University of Manchester and University of Strathclyde	ACHIEVED	The MCS was successfully demonstrated and validated. It was delayed by modifications and upgrades to the MCS's firmware, which needed more testing.
	Knowledge dissemination events as described in the work programme are carried out and results are shared and made available	National Grid ESO	ACHIEVED	Dissemination activities have included stakeholder events, webinars, publications, exhibitions and presentations at other industry events.
	As part of WP6 and WP7, the new balancing service is developed in collaboration with EFCC partners, other service providers, and National Grid's Commercial Operation.	National Grid ESO	Missed	National Grid ESO decided it would not be appropriate to continue developing a standalone EFCC balancing service product in line with 2017 SNAPS proposals.

Table 17b: Project performance against SDRCs

Required modifications to planned approach

The project was originally scheduled to run from January 2015 to March 2018 but was later extended to January 2019. The extension to the project duration allowed additional time to capture and analyse data from the commercial field trials and complete further performance testing on the monitoring and control system (MCS) which will support any potential implementation of the MCS onto the electricity network.

In addition, the project made four significant modifications to the original planned approach. The changes were made to improve the initial project design concepts and to align with the evolving energy industry. The required modifications during the EFCC project are detailed in this chapter.

Chapter 6

System need for fast coordinated frequency response – change of scope

Given the recent developments in the energy industry since the original bid submission, it was decided that a review of the system need for fast coordinated frequency response was required. This re-evaluation of system need became the focus of work package 3 (optimisation), ensuring that there was a solid foundation for any potential future roll-out of a wide area control scheme within the Great Britain (GB) electricity system. This approach also identified a clear implementation strategy for the MCS. The original scope of work package 3 will form part of any future refinements of the MCS functionality.

Monitoring and control system (MCS) – change of approach

As part of the development of the MCS, GE Renewable Energy modified the design strategy for the wide area control system from a centralised to a decentralised approach, as shown in Figures 44 and 45. This change was based on information acquired in the early stages of the MCS prototype, which indicated that a guaranteed response time (of 0.5 seconds) would be challenging to achieve with the communication protocol standards, equipment and communications network available today.

Centralised design approach

In the centralised design (as shown in Figure 44), all local measurements are communicated to a central controller.

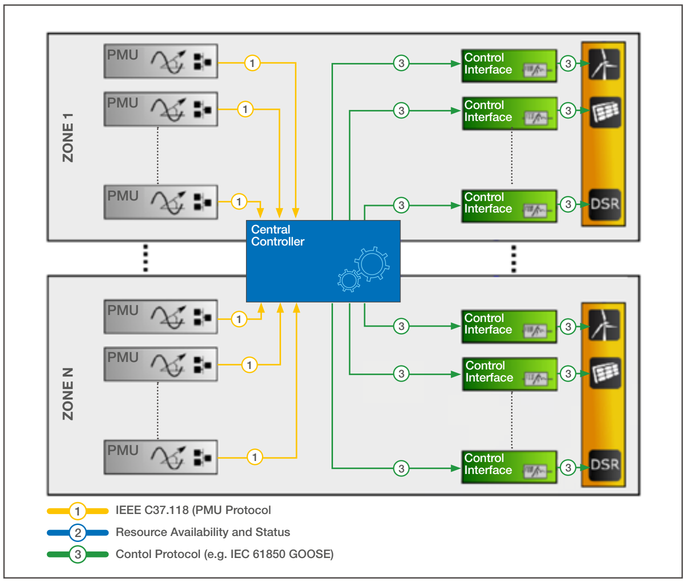


Figure 44: Centralised control scheme design approach

The information is analysed to determine the optimal response which is then communicated from the central controller to each service provider via the Local Controller interface. The approach, which is similar to Active Network Management (ANM) systems, has a centralised function which is responsible for all the data collection, analysis and decision making. The multiple data exchanges between the competent parts can lead to delays in data processing and control actions. It would be dependent on a fast, dedicated communication network, and have a clear single point of failure requiring a robust contingency strategy if it was to be used in an operational environment.

Decentralised design approach

In the decentralised design (Figure 45), each Local Controller (LC) is gathering and sharing system information with each other through the Regional Aggregators (RAs). Each individual LC calculates the total amount of response required, and deploys their contribution to meet the energy imbalance. The Central Supervisor (CS) function is aware of the availability and performance profile of each service provider and will decide and communicate the order in which the service resources will be deployed. The approach is more complex in terms of the communication and system architecture. However, it safeguards against any single point of failure and facilitates graceful degradation if multiple component parts fail.

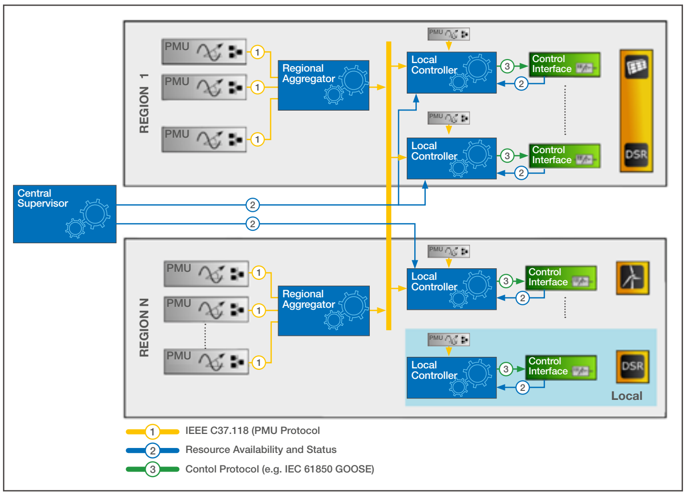


Figure 45: Decentralised control scheme design approach

The design change ensured that the target time (of 0.5 seconds) for detecting, verifying and responding to a frequency deviation would be more achievable. The change in the design also provided benefits in terms of the robustness and reliability of the MCS.

The change in design also required a different MCS testing strategy which was successfully managed by the Universities of Manchester and Strathclyde, working closely with GE Renewable Energy.

Balancing services

During the EFCC project, there were two main changes to the balancing service market that had an impact on the objectives and scope of the project:

i) Introduction of a new balancing service
Enhanced Frequency Response (EFR) – a new frequency response balancing service – was established during 2016. It was defined by the National Grid Electricity System Operator (NGESO) as a balancing service that achieves 100% active power output within one second or

less of registering a frequency deviation[4]. There was an overlap with the speed of provision of this service and the objectives of the EFCC project. However, the EFCC project aimed to provide a faster coordinated response time (target time of 0.5 seconds) primarily from inverter-based technologies operating in low inertia systems.

ii) Future of balancing services[5]
During 2017, NGESO published two key documents: *Systems Needs and Product Strategy*[6] and the *Frequency Response and Reserve roadmap*[7] which outlined changes to balancing services and the frequency response products. These, and subsequent documents[8], outlined that the number of frequency response balancing service products would be rationalised and new services developed with industry consultation. Due to these significant market changes, the original project proposal to develop and implement an EFCC (RoCoF based) frequency response product did not proceed, as any balancing service developed by the project would be superseded by the wider industry review. The associated regulatory funding for developing an EFCC product will be returned in accordance with the NIC governance framework.

Instead, the EFCC project team has shared the commercial trial test results as part of the industry review of balancing services to help develop the new frequency response products. The development of the new frequency response products doesn't mean the MCS can't be used, as its flexible design can be modified to incorporate the technical requirements of the new services.

Commercial trial changes – wind

The original project business case highlighted the participation of Lincs Wind Farm, a joint project venture between Centrica/EPH, Ørsted and Siemens Gamesa Renewable Energy (SGRE), in the commercial trials. Centrica/EPH later announced that it would be selling its interest in the windfarm to a third party[10]. The project team agreed contractual terms with new EFCC project partners Ørsted and SGRE which allowed the wind trial to continue. However, the Lincs Wind Farm could no longer take part in the project trials for technical reasons.

The delays and rescoping of work package 2.5 (wind) meant that using GE Renewable Energy's control unit for the wind farm tests was no longer within the project scope and the trials would not assess the fast frequency response initiated by RoCoF. In addition, after lengthy discussions it was impossible to agree contractual terms that addressed all parties' concerns, particularly on financial liabilities, which would have enabled the trials to be completed on a commercial operational wind farm.

As part of the revised work package activities, analysis was undertaken which would determine and quantify the inertial response (IR) capability from wind farms. These activities included an assessment of a wind farm's ability to provide fast, initiated frequency response without the need to create headroom prior to providing MW response (for low frequency events). The tests took place on an SWT-7.0-154 test wind turbine. The Frequency Sensitive Mode (FSM) function was also tested using more severe settings than specified by the Grid Code at the Ørsted's Burbo Bank windfarm. This provided an increased understanding of the capabilities

Commercial trial changes – batteries

As part of the project direction letter, Ofgem asked for an analysis of available battery storage facilities and a justification report before agreeing to fund an extra battery unit as part of the EFCC project (as shown in Appendix F). This report was submitted to the Authority on 30 June 2015[9] with Ofgem deciding not to fund a new battery storage unit for combined solar PV and battery storage trials (as shown in Appendix F).

The project team considered that battery storage would be important for system reliability in the future and looked for other ways to align the solar photovoltaic (PV) and battery storage hybrid trials with the project scope. NGESO agreed to the use of Network Innovation Allowance (NIA) funding to cover the costs of leasing a battery storage facility. The battery storage device, as shown in Figure 46, was used for the solar PV (Figure 47) and battery storage hybrid trials.

The aim of the trials was to demonstrate whether the solar and battery storage operating regimes can be optimised to deliver rapid frequency response. The trials would also provide valuable information to validate and establish the potential performance of combined technologies.

Figure 46 BELECTRIC's battery system


Figure 47 - Willersey solar farm

Chapter 6

of the existing wind farm fleet for the provision of faster frequency response.

In additional, Ørsted completed statistical analysis using historical wind speed data to determine the probability of obtaining wind IR from their portfolio of offshore wind farms. The University of Strathclyde scaled up the single turbine wind inertial response profile to represent wind farms connected to the electricity transmission network and analysed the system frequency response behaviour when wind IR was used. The analysis provided an indication of the volume of wind IR available across the transmission connected wind farm fleet and determined the operational implications of using that volume of response on the system.

The changes made to this work package still met the original aim of the project of demonstrating a wind farm's ability to provide fast, initiated frequency response. The tests provided an increased understanding of the power recovery period of wind turbines, which is essential to maintain the balance of generation and demand on the electricity system and ensure effective coordination with other frequency response providers.

Chapter 4 (Outcomes of the project) has further information on the trial results.

[4] https://www.nationalgrideso.com/balancing-services/frequency-response-services/enhanced-frequency-response-efr
[5] https://www.nationalgrideso.com/insights/future-balancing-services
[6] https://www.nationalgrideso.com/document/84261/download
[7] https://www.nationalgrideso.com/sites/eso/files/documents/Product%20Roadmap%20for%20Frequency%20Response%20and%20Reserve.pdf
[8] https://www.nationalgrideso.com/document/138861/download
[9] https://www.nationalgrideso.com/document/96456/download
[10] https://www.centrica.com/news/centrica-announces-sale-its-remaining-wind-farm-joint-venture

Updated business case

The original business case has not changed since the project bid was submitted, and the system trends identified when the project started are still valid.

Developments in the energy industry have emphasised the requirement for a faster frequency response and how a wide area control system could assist the future operation of the electricity network. The details below show how these developments have affected the project.

Energy trends

- The key energy trends mentioned in the 2014 bid submission have continued during the EFCC project. As expected, there has been a continued reduction in the volumes of large-scale thermal generation, with a corresponding increase in the levels of renewable generation and distributed connected generation. These trends are expected to continue into the next decade, as outlined in NGESO's *Future Energy Scenarios*[11].

Market changes

- A new balancing service, Enhanced Frequency Response (EFR), was introduced during the EFCC project. This new service achieves 100% active power output at one second or less of registering a frequency deviation. The introduction of this service re-emphasised the system requirement for a faster frequency response product.

  There was an overlap with the speed of provision of this service and the objectives of the EFCC project. However, the EFCC's aim was to provide a faster coordinated response time (i.e. 0.5 seconds) from inverter-based technologies. The EFCC project also developed a wide area control system that will detect RoCoF and reliably coordinate a proportionate response from service providers.

Technical performance modifications

- The Grid Code and Distribution Code specify the technical functionality and performance criteria for generation plant connected to the electricity network. Two changes had a direct impact on the solution proposed by the EFCC project:
  - GC0079[12] and DC0079[13] – frequency change during large disturbances and their effect on the total system
    Approved by Ofgem in 2018, the code modification specifies that a non-type tested embedded generator that uses loss of main protection should be set to 1Hzs^{-1} with a definite time delay of 500ms. These changes apply to existing and new generation plants; a phased implementation period is being agreed by affected parties.

20%

Large scale synchronous generation has reduced by nearly 20%

x3

Generation connected to the lower voltages networks has tripled

x2

Non-synchronous generation connected to the electricity system has doubled

-50%

Carbon intensity of electricity system has decreased by 50%

[11] http://fes.nationalgrid.com/fes-document/

[12] https://www.nationalgrideso.com/codes/grid-code/modifications/gc0079-frequency-changes-during-large-disturbances-and-their-effect

[13] http://www.dcode.org.uk/current-areas-of-work/dc-0079.html

Chapter 7

When this change has been fully implemented, it will allow the RoCoF to increase across the system. This means that the NGESO must have the capability to respond to frequency deviations more quickly than current operation parameters. The MCS, developed by the EFCC project, is a tool that could help with this new operational requirement.

- GC0101: EU connections codes GB implementation – Mod 2[14]
  The code modification, implemented in May 2018, requires that a non-synchronous plant should respond no later than one second to a frequency deviation when in Frequency Sensitive Mode. This applies to non-synchronous plant that connects to the electricity network on or after the implementation date and is 10MW or above in size. The modification increases the amount of generation that could provide a frequency response service to the NGESO and could possibly be used by the MCS, if implemented.

Regional vs national frequency response

- The Network Innovation Competition (NIC) VISOR project[15], which concluded in 2018, gave improved real-time system monitoring data of Great Britain's (GB) electricity transmission network. This increased the visibility of the dynamic behaviours on the network and provided evidence of one of the key principles of the project: that frequency is not the same across the network immediately after an event, as shown in Figure 48.

  As system inertia continues to reduce with the corresponding increase in the RoCoF, it's even more important that the system can respond more quickly to a frequency event to keep the grid stable. However, responding more quickly is not enough. This is because frequency is also changing across the system. Different regions of frequency fluctuation can drive oscillating behaviour if service providers base their response on only local frequency measurements. It is important that the fast response provided is proportionate to the national system frequency, so there are no prolonged frequency fluctuations on the network.

The MCS can instruct frequency response providers in a proportionate manner, making sure that an efficient and effective response is provided quickly.

NGESO's System Operability Framework (SOF) takes a holistic view of the changing energy landscape to assess the future operation of GB's electricity networks. The

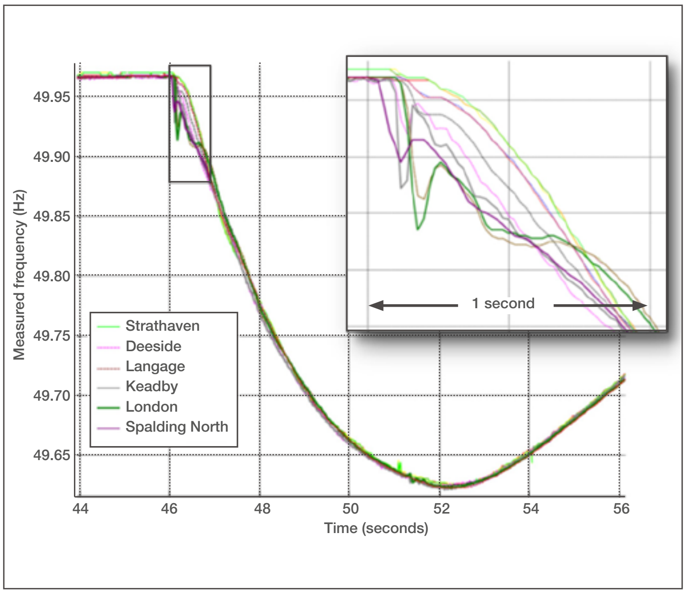


Figure 48: System frequency divergence immediately after an event

reduction in system inertia has been identified as one of the key challenges that needs further analysis and requiring novel solutions such as the one developed by the EFCC project. The EFCC project learning and concepts may also be applied to several other system operability issues, for instance harmonics and imbalance, system restoration and voltage stability. See Appendix G for more information.

There's more information on the SOF at https://www.nationalgrideso.com/insights/system-operability-framework-sof

[14] https://www.nationalgrideso.com/codes/grid-code/modifications/gc0101-eu-connection-codes-gb-implementation-mod-2

[15] https://www.spenergynetworks.co.uk/pages/visor.aspx

Finances

The NIC EFCC project shows an expenditure of £6.3m (as of April 2019). Table 18 shows the final project spend against allocated budget (figures accurate as of 30 April 2019).

Budget at Dec 2014 NIC Sign Off (£k)	£7,932.69 (including regulatory funding and licensee contribution)
Descoped WP2.4 Storage (£k)	£908.64 (excluding project partner funding)
Forecast budget (£k)	£7,024.05 (including regulatory funding and licensee contribution)

NIC cost category	Forecast budget £K	Actual spend £K	Spend v. forecast (%)	Variance +/- 10% commentary
Contingency	£708.32	£428.73	60%	Full contingency not required to meet project objectives
Contractors	£2,349.73	£2,535.90	108.0%	Extra support required to install hardware on the transmission network to provide additional knowledge of the MCS
Decommissioning	£24.00	£0.55	2.3%	commercial trials were used to achieve the project scope
Equipment	£574.00	£614.34	108.0%	
IT	£86.00	£60.74	70.6%	Less commercial trials were used to achieve the project scope
Labour	£2,150.00	£1,952.01	90.8%	Efficient use of resources to achieve project scope
Other	£340.00	£121.22	35.7%	Revised approach to achieve project scope
Payments to users	£653.00	£475.63	72.8%	Less commercial trials were used to achieve the project scope
Travel & expenses	£139.00	£97.83	70.4%	Regular Project Delivery Team meetings held via teleconference where possible to reduce time and travel costs
IPR costs	£0.00	£0.00		
Total £K	**£7,024.05**	£6,286.95	89.5%	
Interest shortfall £K	-£196.94			
Actual total budget £K	**£6,827.11**	£6,286.95	92.1%	**Actual Total Budget £K**

Table 18 - Summary of EFCC financial budget

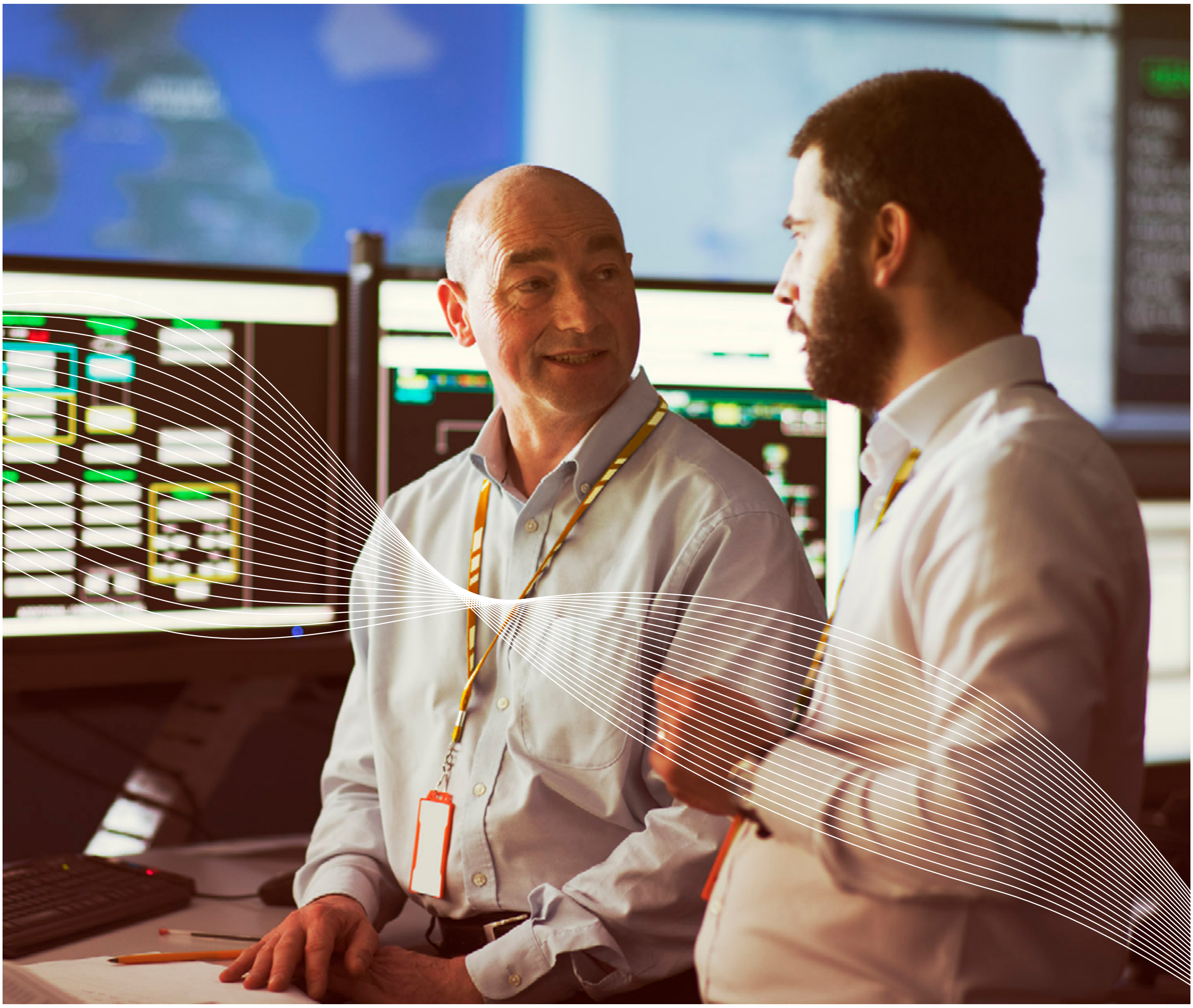
Return of underspent NIC funding

In line with Electricity Network Innovation Competition Governance Document v 3.0, sections 8.70-8.77, the EFCC project will be returning Category 2 revenues "underspent NIC funding, because of the project acting in line with its Project Direction". Detailed financial figures are confidential and will be provided to Ofgem alongside this project close down report.

Lessons learnt for future innovation projects

Tackling the design and testing of the monitoring and control system (MCS) in conjunction with the commercial field trials has been incredibly beneficial as it has helped the project team to develop a robust and reliable MCS.

However, the nature of such a multifaceted project has been complex, with the commercial work stream continually having to adapt to reflect the evolving energy landscape and markets. Challenges also arose in completing all the project trials within the original timeline. Given the challenges faced, it was important to make sure that all project partners were fully aware of the impact that any change in project approach and timeline might have in another area of the project. Strong communication within the whole project team helped to mitigate potential risk areas, and methods for improved working have been discussed in regular Steering Group meetings.



A summary of key learning is shown Table 19 below, categorised into lesson type and what our mitigating actions were.

Lesson category	Lesson summary	Mitigating actions
Project planning	Early involvement from industry experts and academia	A broad range of technology providers and specialists was needed for this project to succeed. It is recommended that any specialists required are identified early and advised during the project set-up stage (e.g. project partner contractual agreements).
Project execution	During project start-up, ensure key milestones and Successful Delivery Reward Criteria (SDRCs) are fully understood, measurable and transparent	It is advisable to clarify SDRC expectations and interpretations of them as early as possible, so all parties agree on what is deliverable and by when.
Team	During the project, key personnel changes were made within partner companies and at National Grid Electricity System Operator (NGSO)	It is advisable to expect and plan for personnel changes and possible company takeovers.
Team	Working collaboratively	Innovation projects require a strong ability and willingness to work through ambiguity and change. Making sure the project team comprises collaborative and motivated people is essential to deliver the project's objectives.
Project close	The need to begin collating results, messaging, engagement and concluding trials before the official project end date	Engaging early with all relevant business stakeholders is essential to establish clear lines for next steps and sharing learning from project outputs within the project completion date. This activity is significant and should not be underestimated.
Business as usual	Forward thinking	Within the project objectives it is advisable to consider potential market changes during the project along with broader solutions to market challenges.
Stakeholders	Importance of engagement	A comprehensive communications plan is required to keep stakeholder engagement appropriate and relevant. This plan needs to be managed by a dedicated resource with communications experience. This plan should align with the overall project plan and be familiar to all team members.
Project planning	Project milestones and work packages should be adaptable to achieve the project's overall objective in response to project findings or changes in the landscape	The EFCC project adapted and identified aspects that required further development which were unforeseen at the outset. By carrying out additional initiatives, the project is in a stronger position to deliver a successful outcome.

Table 19: Summary of key project learning

Above is a summary of learning achieved by the project team. Should further information be required please do not hesitate to contact the project team using the contact details provided in Chapter 14.

Note to networks – the project team would like to support cross-network lesson sharing. Please do not hesitate to contact the project team to discuss learnings in further detail.

Project replication

This section provides information on how this project could be replicated.

System need for coordinated fast frequency control

The algorithms developed in DIgSILENT PowerFactory to simulate the three alternative control scheme modes were modelled manually using DIgSILENT Simulation Language (DSL) functions and DIgSILENT Programming Language (DPL). These functions can be replicated within a DIgSILENT model to fully automate the analysis, subject to the availability of generation and demand data and access to a representative model of the National Electricity Transmission System (NETS).

The algorithms which replicate the methods of the wide area control constitute intellectual property that has been developed by the project. National Grid Electricity System Operator (NGESO) and the University of Manchester will jointly grant access to the developed algorithms on request in line with the data access sharing policy outlined in the 'Data access details' section of this report.

The DIgSILENT PowerFactory 36-bus model representation of the NETS contains commercially sensitive information and as such, the NGESO will consider granting access to this model on a case-by-case basis, using a non-disclosure agreement.

Monitoring and control system (MCS) development

To replicate the functionality of the MCS, algorithms would have to be developed for each of the control components. The algorithms were designed around the key features of the control scheme:

- fast detection of a system frequency event (<500ms)
- calculation of national system frequency and national equivalent RoCoF
- from the system frequency calculations, derivation of the volume of active power needed to balance generation and demand after a system frequency event
- identification of the location of the imbalance within the network via comparison of voltage angles across the network
- coordination of response from multiple service providers to match an appropriate response to the deficit in active power balance, based on the RoCoF being observed at the time
- deploy frequency response proportional to and targeted towards the location of the system frequency event
- keep an active portfolio of the live resources available for frequency response.

The high-level algorithms are shown in Figure 49. The main algorithms developed were (including where they sit within the MCS architecture):

- regional aggregation (Regional Aggregator)
- system aggregation (Local Controller)
- event detection (Local Controller)
- resource allocation (Local Controller)
- optimisation (Central Supervisor).

Each of these algorithms is referred to as an application function block (AFB) in the control system. It's possible to build a control system using these AFBs from a library in the Programmable Logic Control (PLC) environment for the functions within each controller.

Most of the AFBs are concentrated within the Local Controller (LC). Due to the decentralised nature of the control strategy, each LC can take independent action based on receiving equivalent real time information of the frequency event. The LC has two modes of operation; wide area mode and local mode. In the wide area mode, each LC is aware of its position within the whole MCS by receiving information from the Central Supervisor (CS). In the local mode, the LC is not linked to either the Regional Aggregator (RA) or the CS.

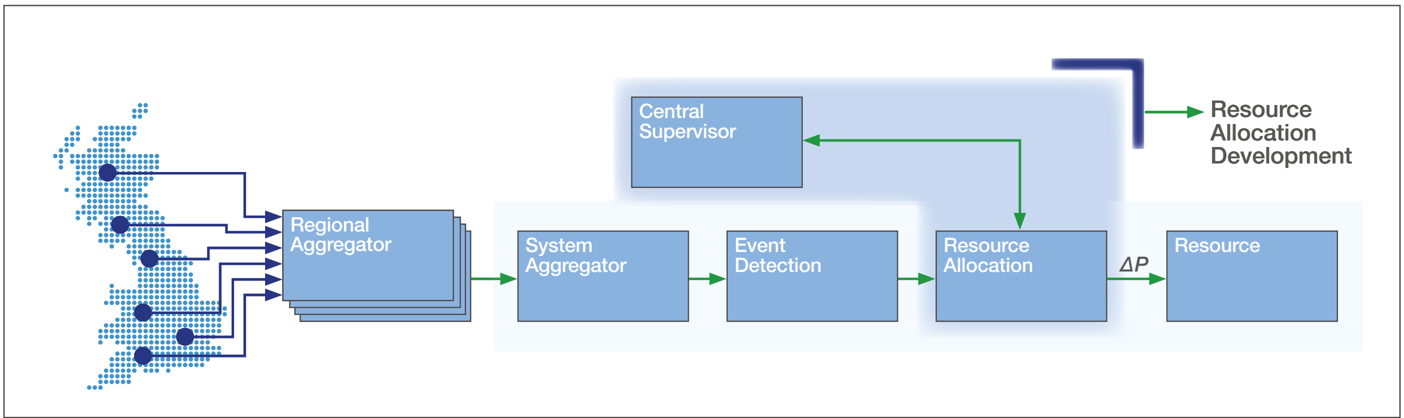


Figure 49: Algorithms in context of the scheme

This decentralised control strategy requires the data from RAs and LCs to be broadcast via a fast communication network to all controllers during an event. In contrast, updates to the settings of the MCS, availability of service providers and the frequency response characteristics of service providers are achieved via slower communications channels.

Regional Aggregator

The electricity transmission system will be split into regions for the MCS configuration and each region will have one RA. Their key functionality is to aggregate outputs from the phasor measurement units (PMUs) located within their region into values that represent an equivalent signal for that region. The RA consists of two algorithms: a "weighted" averaging function to combine the regional signals and a fault analysis algorithm to detect electrical faults within that region.

The weighted averaging function performs the important role of filtering out local oscillatory behaviour within the region before calculating the national equivalent frequency and rate of change of frequency (RoCoF). This is achieved by "weighting" the measurements received by the RA. This weighting represents a proportion of the inertia on the system that is local to the PMU location on the NETS. Generation and demand changes, plus outages on the NETS, mean that these weighted values need to be updated to maintain a representative aggregation measurement.

The RA also functions to reduce the amount of data that is transferred across the communication network. This has the advantage of reducing the bandwidth requirements of the communication network, and potentially minimising the costs of communications infrastructure.

The fault analysis function seeks to identify local electrical fault conditions by measuring the voltage depression and/or loss of PMU data within a region. In these conditions the fault analysis function defines precautionary delays to deploying response within the region.

Where PMU data is lost due to a system fault within a region, the weighted averaging function in combination with the fault analysis function is able to identify a reduction in system inertia. Data quality thresholds for the regional data have been applied within the RA.

The aggregation of frequency and angle signals, plus consideration of weights assigned to measurements and their data quality is important for the graceful degradation of the system. The quality of the RA output is defined as a confidence level, which describes the confidence that the output correctly represents the overall region's behaviour (frequency and angle).

Local Controller

The LC issues commands to the frequency response resources and receives local PMU data from its connection point on the network. For the purposes of the project, the LCs were located next to frequency response providers. However, depending on the roll-out strategy of the MCS, its functionality is able to cater for response providers being remote from the LC, athough this will need careful calibration between the location of where measurements are taken and where the response is provided. The LC contains three key algorithms: **System Aggregation, Event Detection** and **Resource Allocation**.

System Aggregation performs a similar role to the RA. It receives an equivalent aggregated and weighted value of frequency from each region of the network and produces a weighted aggregated system equivalent value of frequency and RoCoF during a frequency event. A confidence level for each of the RA outputs is included in the overall aggregation.

If the LC is unable to obtain a signal that represents the system with enough confidence, it will ignore that data and rely on local measurements using the local mode until data from the wider system improves, at which point it will revert to wide area mode operation. This is an example of graceful degradation, where instead of stopping, the system will resort to using local measurements, provided they are of sufficient quality, to continue operating, but with reduced capability and slower overall operation. Slower operation is needed when the LC is in local mode to filter any "noise" associated with local measurement oscillations and apply that to the data, before initiating control signals for response. This slower operation avoids any worsening of the system frequency deviation.

The **Event Detection** detects events based on aggregated system frequency, as well as the reported frequency of the local PMU. The event detection is based on RoCoF using a novel fast detection algorithm. When an event is detected, the algorithm will capture the pre-event voltage angles that are needed by the Resource Allocation algorithm to identify the location where response is to be deployed.

The **Resource Allocation** calculates the amount of response to deploy from the service providers after an event has been detected. It seeks to deploy this response as quickly as possible, taking the equivalent system RoCoF into account. The Resource Allocation activates tiers of response against defined frequency and RoCoF trigger points to limit the extent of frequency deviations propagating across the electricity system. It uses information from the service providers (e.g. MW, ramp up/down characteristics) and the CS status information to form a coordinated deployment. The Resource Allocation is continually polling the wide area data during the event to confirm sufficient and appropriate response is being deployed to limit and damp any oscillation in overall response delivery. It also uses information from the Event Detection to determine the system movement caused by the frequency event. From this, it determines where the LC is in the resource portfolio, prioritising the control action closest to the frequency event location. This AFB also manages the deployment of additional frequency response if there is insufficient response within a region or subsequent frequency events.

Central Supervisor
The final element of the MCS is the CS, which provides the coordination and supervisory role. The CS gathers system information from the NGESO and all the service providers connected to the MCS to perform an optimisation function. This optimisation is to organise all the services providers that can be accessed to stack their characteristics depending on the volume, MW ramping and duration to meet the overall response requirement. This forms a portfolio of all resources that are available in the system for frequency response. The priority of the resources to be deployed is sent to each LC, so that in real time the response is delivered based on the size of the RoCoF event that is calculated.

The aim of the optimisation algorithm is to organise the portfolio of resources for the most efficient response, (i.e. prioritising the fastest response to halt a frequency excursion sooner). The CS will then issue the optimised information to each LC where response can be deployed according to the optimised resource profile and use the resource in the most efficient way.

MCS performance validation
Details of the university validation approach and test conducted are outlined in Chapter 3 (Details of the work carried out). Further information on the equipment setup and software needed to repeat the tests are fully described in the technical reports published on the project website. Where reference is made to GE Renewable Energy PMU devices PhasorController and PhasorPoint, alternative manufacturers or suppliers can provide the same functionality.

A reduced 36-bus NETS model was provided by NGESO to the universities to analyse how the MCS would perform against a variety of generation and demand scenarios.

University of Manchester
The following equipment and software are needed to replicate the Hardware-in-the-Loop (HiL) testing approach using a Real Time Digital Simulation (RTDS) to physically connected to the MCS controllers. Figure 50 illustrates the physical equipment.

Required hardware equipment:
- six GE Renewable Energy PhasorControllers
- time synchronisation: one GE Renewable Energy Reason RT430
- ethernet switches: one GE Renewable Energy Reason S20
- network simulator: RTDS with two racks
- simulation control and results recording: two PCs.

Required software:
- RSCAD: modelling of the network and control of RTDS
- PhasorPoint: real-time PMU data monitoring and recording
- PhasorController Designer: IDE for PhasorController
- IED scout: tool for IEC 61850 configuration of PhasorController and RTDS
- PuTTY: SSH and telnet client for PhasorController
- WinSCP: file manager of PhasorController.

University of Strathclyde
The University of Strathclyde established a highly realistic testbed that coupled a NETS simulation model in RTDS with an 11kV physical network using a Power-Hardware-in-the-Loop (P-HiL) configuration, which is shown in Figure 51.

Required hardware (unless specified, only one is needed):
- GE Renewable Energy PhasorController: five (three RAs and two LCs)

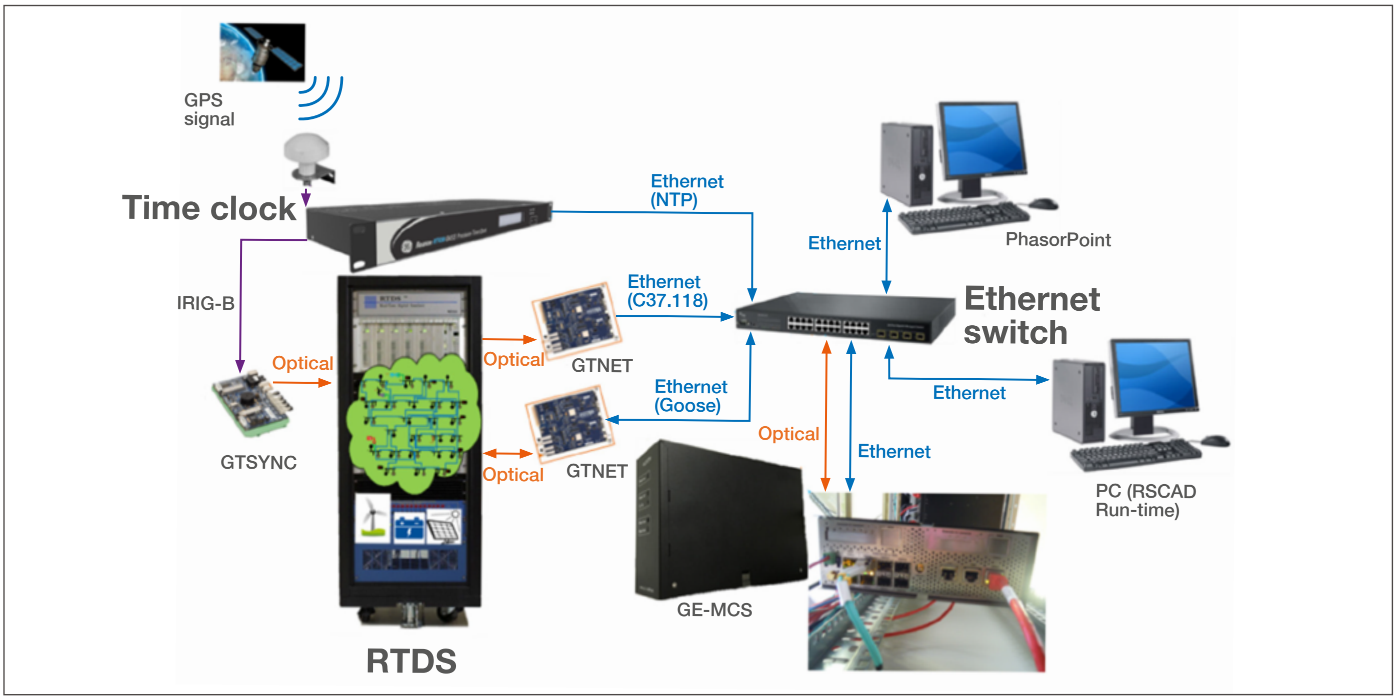


Figure 50: Physical connection of the various devices required for the tests at UoM.

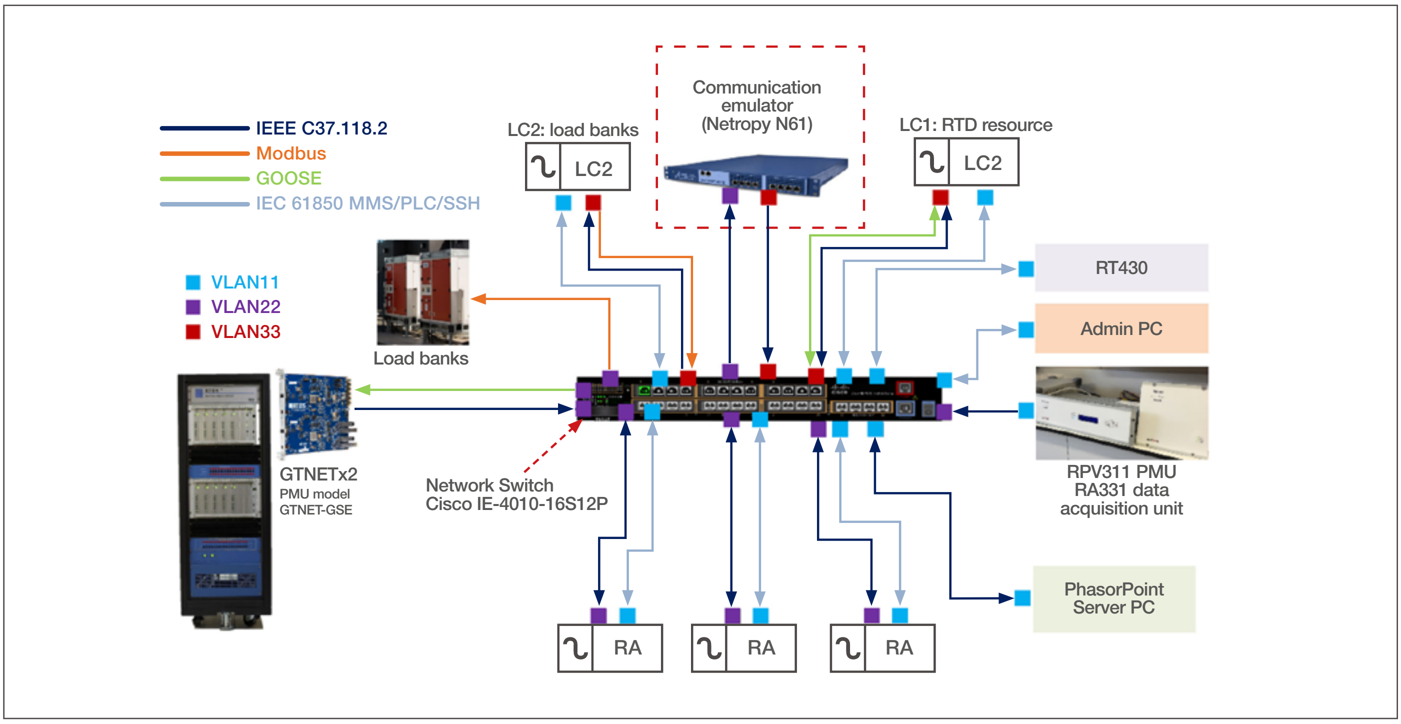


Figure 51: Physical connection of the various devices required for the tests at PNDC.

- Netropy N61 communication emulator
- Cisco IE-4010-16S12P industrial ethernet switch
- real time simulator: RTDS with two racks (GTNET card with PMU and IEC 61850 firmware)
- GE Renewable Energy RPV311 PMU
- GE Renewable Energy RA331 data acquisition unit
- GE Renewable Energy GPS grand master clock (RT430)
- simulation control and results recoding: two PCs (one admin PC for running RTDS simulation, PhasorController Designer and configuration of the controllers, and one for PhasorPoint server).

Required software:
- RSCAD: modelling of the network and control of RTDS
- PhasorPoint: real-time PMU data monitoring and recording
- PhasorController Designer: IDE for PhasorController
- software for IED configuration (e.g. IEDScout, IEDExplorer, etc.)
- PuTTY: SSH and telnet client for PhasorController
- WinSCP: file manager of PhasorController.

Technology assessment for fast frequency response with the MCS

Demand side response

The test setup for the Static RoCoF, Dynamic RoCoF and Spinning inertia trials will be particularly sensitive to the operational activities and the technical configurations of the sites selected. The configuration of the site setup and processes used in the project are outlined below.

Site setup – Static RoCoF

A GE Renewable Energy PMU consisting of an RA332 acquisition unit, RPV311 recorder and RT430 GPS clock and PhasorController were connected on site. The trip signal was wired via a timer so that the trip lasts for 30 minutes on each occasion. This trip period was chosen purely because existing frequency response participants are accustomed to it; a shorter or longer period could be considered depending on the load type. The timer is powered only when the site is ready to respond to Static RoCoF.

RoCoF trip settings were discussed with the site operator to decide on the number of trip events to minimise the impact on the site's operation. The PhasorController's settings allow the users to define the behaviour of the detection algorithms, such as changing thresholds and adjusting sensitivities, and these settings need to be tuned to the specific frequency experienced at the site location to prevent overtripping of the site.

Data from the PMU and the PhasorController was constantly recorded using PhasorPoint. This allowed the frequency calculated by the PMU, RoCoF calculated by the PhasorController, the state of the frequency event signal (i.e. whether frequency breached the required threshold) and resource allocation signal (i.e. whether the frequency event was long enough to require power delivery), to be observed.

Site setup – Spinning Inertia

To convert the sites for the project trial, the combined heat and power units (CHPs) were adapted to operate at a reduced power level, rather than the normal full power mode. This involved reprogramming the site controls and adding new signals to the relevant interfaces to indicate when the new mode of operation was to be started or stopped.

Different methods of data collection had to be used between the sites to provide the granularity needed for RoCoF analysis. At the large greenhouse, a PMU monitored data only and the output was sent to PhasorPoint. An alternative method used at the district heating site was to install a National Instruments cRIO-9038 data logger in a dedicated cabinet. The data logger monitored voltage and current sensing supplies and site specific layout challenges meant that only one CHP unit could be monitored.

Site setup – Dynamic RoCoF

Sites that are suitable for Dynamic RoCoF are typically smaller than those used in the other two trials, so a PMU and Local Controller to detect RoCoF were not used. For Dynamic RoCoF to be viable as a service, it must be economic to use on these smaller sites. So, one of the objectives was to demonstrate that this could be done relatively cheaply using a slightly different detection algorithm.

The chosen equipment was an Allen Bradley Micro 800 series controller and also included an off-the-shelf frequency transducer. The frequency transducer converts the mains supply voltage into a 4-20mA analogue signal which is fed to the Allen Bradley. The performance of commercially-available frequency transducers varies widely; while many models could be suitable, they don't all have the necessary speed and accuracy.

The Allen Bradley controller fulfills three roles:
- calculates RoCoF from the mains supply and produces an analogue output signal that indicates the power deviation requested to the site
- acts as a bridge between the site controls and the Flexitricity outstation, converting signals into the appropriate format
- produces logs of detected frequency and calculated RoCoF.

Further detail about how the Allen Bradley controller produces an analogue output that is proportional to RoCoF, scaling and dead band filtration is available in the '*Demand Side Management Approaches to Enhanced Frequency Control in Low Inertia System*' technical report that is available on the project website.

Solar PV and battery storage hybrid system

The test setup for BELECTRIC's photovoltaic (PV) and battery storage hybrid trials will be specific to the Willersey used for the project. Figures 52 shows the communication setup of the plant.

Required hardware and software:
- GE Renewable Energy PhasorController: Local Controller
- GE Renewable Energy RPV311 phasor measurement unit
- GE Renewable Energy RA331 data acquisition unit
- GE Renewable Energy GPS grand master clock (RT430)
- simulation control and results recording: one PC for configuration of the controller, and PhasorPoint
- PMU simulator (shown as GS in Figure 52)
- LAN cable connection to link all components of the solar PV plant using MODBUS TCP communications protocol
- SteadyEye sky imager camera
- PV monitoring application; PADCON web portal
- SCADA system.

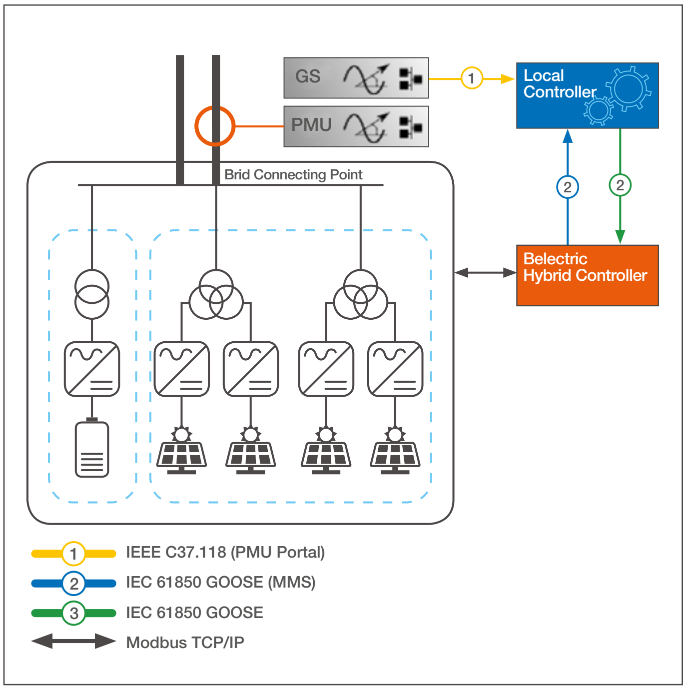


Figure 52: Communication setup with PMU simulator

A local area network (LAN) cable was used to monitor and control the solar PV plant, including temperature sensors, irradiance (from the pyranometer), voltage and current data form the PC modules and inverters.

BELECTRIC developed a hybrid controller to coordinate the frequency response between the solar PV plant and the battery storage unit. This controller is connected via IEC 61850 generic object oriented substation event (GOOSE) communication protocol to the LC.

A PMU simulator tool was used to test the hybrid system in the absence of real frequency events. The simulator injects simulated frequency data into the LC with predefined RoCoF and frequency values. This allows the capability of the plant to be fully tested without waiting for a particular RoCoF event, thereby speeding up the number of tests that can be achieved.

Forecasting and MATLAB modelling

A SteadyEye sky imager camera was used to assess cloud movement and estimate the global horizontal irradiance that would be available within the next 15 minutes. A probability value of p40 was set in the sky imager camera. This means that the probability of the real power exceeding the forecasted power is 40%, however other settings in the camera are available. This setting gives a constant, slight underestimation in the forecasted power which is preferable than an overestimation that could lead to a potential over delivery of response. Any over delivery of response after a frequency event could cause challenges with coordinating with the overall response within the MCS to recover the frequency.

The forecasted power was converted and utilised within a MATLAB PV model specifically developed by BELECTRIC for this project. The model simulates the characteristics of the plant to calculate its output power using real-time data from a sensor to gather PV cell temperature, inverter temperature and solar irradiance measured by a pyranometer. This model enhanced the trials and showed the capability of the plant in the absence of electricity system frequency events.

Data logging systems
More than one data logging system was used at the solar PV and battery unit site to monitor, collate and coordinate the data across both technologies. These systems are described below:

- PADCON PV monitoring portal
  PADCON PV monitoring is a web based portal that was used to observe the output from the solar PV inverters and associated sensors at the PV site. The data resolution of the monitoring portal is 1s, and therefore the GE Renewable Energy acquisition unit was used to improve the resolution to 20ms.

- SCADA system
  A SCADA system was used to gather and process real-time data for the PV and battery units. It also stored the electrical parameters of the battery unit and gathered data from the battery control system.

- Battery control system (BCS)
  The battery control system was configured to log the active power of the battery unit with a time stamp. The BCS clock was synchronised with a GE Renewable Energy GPS grand master clock as were the hybrid controller and PMU. This allowed the individual output data from the PV inverters and battery unit to be compared to find the overall response. However, some interpolation of the BCS data is needed due to the uncertain response time when using a shared MODBUS communications channel.

Impact assessment of the MCS on operational systems

To replicate the testing of the PhasorControllers connected on a segmented network it would require a setup that contains the following:
- three PhasorControllers (one LC, one RA, one CS)
- three multifunction routers, with firewalls and Virtual LAN (VLAN) or Virtual Routing and Forwarding (VRF) capability
- PMUs or PMU simulator
- administrations workstation, with Straton PLC, Notepad ++, PuTTY, internet browser
- GPS signal for time synchronisation.

This will allow a network to have a setup representative of an operational wide area communication network. Each VLAN or VRF would have its own subnet which would be firewalled off from all other logical networks and would require a gateway to control routing between networks.

Figure 53 shows how a high level test environment can be set up. This could be scaled up with additional RAs, LCs and PMUs or PMU test streams. A local PhasorPoint or phasor data concentrator is not essential, but is useful for recording any test results.

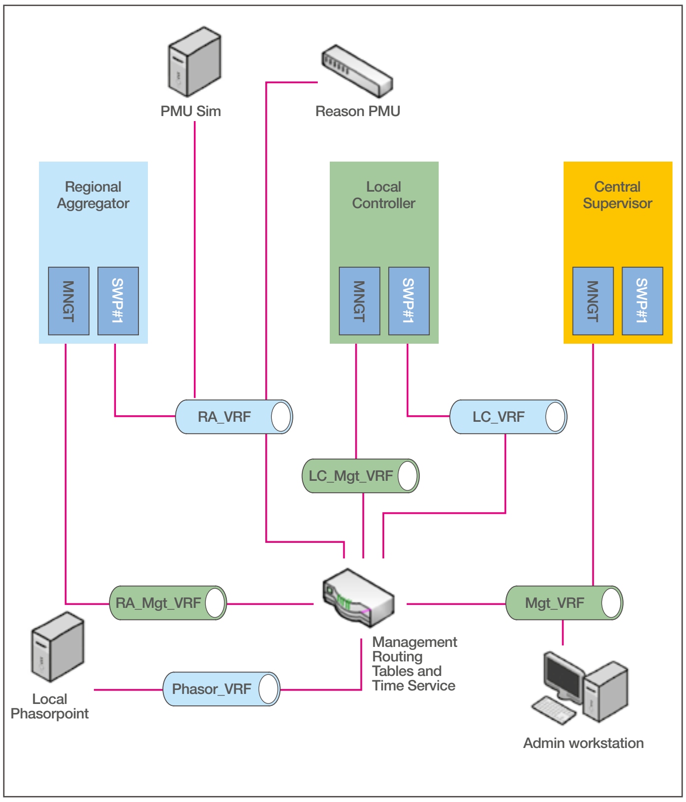


Figure 53: High level network test environment

Planned implementation

A phased approach to any potential implementation of the monitoring and control system (MCS) is needed. This will include a full assessment of the how the MCS will operate on the live electricity system which will help to increase the technical readiness of the system before any potential roll-out. Consideration must also be given to the new commercial framework and IS interfaces with National Grid Electricity System Operator's (NGESO) balancing system before any implementation to understand the impact and necessary interfaces. These interfaces were discussed in the '*Impact assessment of the MCS on operational systems*' report available on the project website.

This phased approach will help the transition of this complex scheme to be carefully managed and coordinated with other industry strategies.

Phased implementation approach for the MCS

The sections below show a phased approach (outlined in Figure 54) to the implementation of a wide area control system which will fully assess the impact on business processes and systems, with appropriate stakeholder engagement at each step. In addition to the specific areas of development for the MCS, the implementation phases are also described. These phases and associated activities do not preclude the use of an alternative wide area control scheme which can provide the same functionality as the MCS.

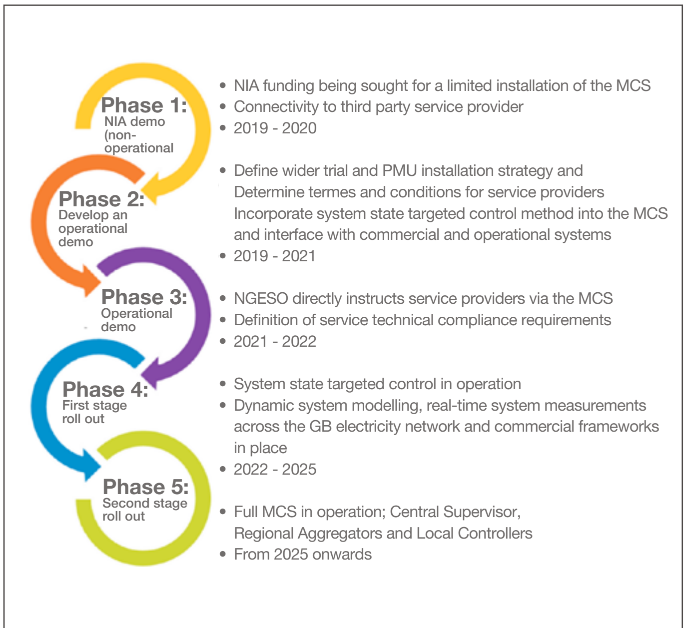


Figure 54: Outlines the high level phased implementation approach

Phase 1: Proposed Network Innovation Allowance (NIA) MCS demonstration

The first phase of implementation would need to show how the MCS will operate on the existing communications network. It should also consider the commercial framework and IS interfaces that would be needed to support the scheme. Alongside these technical and commercial assessments, further refinements to the MCS will be completed to increase its technical readiness level (TRL). These refinements are needed before any physical trial of the MCS can take place that operates service providers directly from the NGESO control room.

Determining how the MCS will function on National Grid's communication network is vital to any implementation. However, it must be done in a controlled manner that will not impact the operational performance of the electricity network. The MCS demonstration will confirm how the control system will perform in an operational environment, as well as test the existing communications infrastructure and interfaces.

The main objectives of this phase are to:

- validate the entire scheme and monitor its response to real system events
- to define a cyber security benchmark for any future wide area control schemes
- define the technical requirements to connect a commercial response provider
- to define PMU and performance requirements for wide area monitoring and real time data acquisition from an NGESO perspective
- inform how National Grid can utilise wide area monitoring and control (WAMC) approaches to resolve operational challenges (e.g. stability) in low inertia systems.

The demonstration is being assessed for Network Innovation Allowance (NIA) funding and is subject to approval. If NIA funding is obtained, the MCS demonstration will take place during financial year 2019/2020.

Phase 2: Development of end-to-end MCS demonstration

This phase would involve a limited deployment of the MCS (in a specific region of the transmission network), and increase the TRL of the system by fully integrating it with planning, commercial and control room tools and applications. The MCS will be required to move to an enhanced, more secure operational environment (such as Critical National Infrastructure) that would allow the NGESO to enact the control scheme.

The choice of network region for the demonstration would have to be considered with transmission and distribution licensees to establish any mutually beneficial opportunities of selecting an area of the network.

Discussions will also be required with the transmission and distribution licensees to ensure suitable coverage of phasor measurement units (PMUs) on the electricity network and access to PMUs for operational control.

The performance specification of PMUs for operational control has been reviewed in this project. P-class PMUs have a lower latency in data transmission than M-class PMUs which would be preferred for wide area control systems. This lower latency is due to the reduced measurement time, and this needs to be balanced against the accuracy of the amount of response deployed by the MCS. In most cases, the operation of a PMU in either P-class or M-class is a selection mode on the same physical device, so it may be possible to use existing units to minimise any potential replacement/upgrade costs.

The MCS would also need further refinement. Any outcomes and learning from Phase 1 should be addressed at this point. The system state targeted control method developed and analysed by the University of Manchester as part of evaluating the system need for fast frequency control would need to be implemented and tested before the next phase. These activities would need cross-industry and academic involvement.

Frequency response providers across the industry would be contacted to find participants willing to install Local Controllers (LCs) for the demonstration. A review of their technology response capabilities, communications and control systems for providing fast response using the MCS would also be needed.

As part of this engagement, commercial agreements will be negotiated with participants:
- which will allow them to be instructed for frequency response via the LCs
- understand interactions with other ancillary service provisions, and
- agree any remuneration terms and conditions.

In addition, the commercial and technical connection compliance requirements for delivering a service via the MCS need to be developed. As part of specifying the requirements, consideration needs to be given to how distribution service providers will connect to the LC either individually using an internet connection or physical communication link, or through a demand side aggregator.

Phase 3: End-to-end MCS demonstration
This phase is the enactment of the activities from Phase 2. The MCS deployment is limited and the NGESO control room can directly instruct some service providers via the MCS. This phase would last for approximately one year to fully validate operation across all seasons and iron out any process or systems challenges.

In a similar way to Phase 2, discussions need to take place with the transmission and distribution licensees regarding PMU coverage and access arrangements. The commercial and technical compliance requirements would continue to be defined.

Phase 4: First stage roll-out of the MCS
The first stage roll-out of the MCS would be using the system state targeted control approach with the Central Supervisor (CS) and LCs. The MCS would be fully launched as an operational tool with an increased number of response providers delivering response within the commercial response framework.

After this initial roll-out of the MCS, consideration needs to be given to the potential next phase that incorporates the Regional Aggregators (RAs). As discussed in previous chapters, defining the number of regions across the network is important and will affect how the MCS deploys response close to the frequency event. Initial systems analysis of regional rate of change of frequency (RoCoF) has identified at least 12 regions across Great Britain's (GB) transmisson network: two in Scotland and 10 in England and Wales.

The number of regions across the network are influenced by circuit outages, prolonged circuit faults, changes to network topology and the connection of new large sources of inertia. This means the regional definitions would need to be kept under review and incorporated into business processes.

In evaluating the number of regions, it is important to note that more RAs can potentially improve the aggregated frequency representation on the network. However, increasing the number of RAs will increase the amount of data bandwidth in the communications architecture. Therefore, a compromise between the communications network and the number of regions will be needed.

The location of PMUs that connect to the RAs will be influenced by the anticipated inertia conditions and sufficient PMUs must exist within an area to ensure that a single loss of a PMU (for example due to a generation disconnection) does not result in an unacceptable degradation in data quality. Further studies on PMU placement and associated weighting of generation types needs to be optimised for the next stage of implementation.

Phase 5: Second stage roll-out of the MCS
This final phase of the roll-out would require all the functionality of the MCS to be implemented. In addition to the MCS components from Phase 4, RAs would be installed on the electricity transmission network. The additional functionality of the RAs that is required from 2025 onwards is based on the University of Manchester analysis (as described in Chapter 4 (Outcomes of the project)) which has indicated that due to the continued reduction in system inertia, targeting response close to the frequency event is crucial to maintain system frequency.

Chapter 11

Business requirements to support the MCS roll-out

The outcomes summarised in Chapter 4 (Outcomes of the project) "Impact assessment of the MCS on operational systems" highlighted the changes needed to operational systems to support the implementation of the MCS.

Some of these business process improvements are currently being development by NGESO through separate initiatives and/or formal code changes, outlined as follows.

Network studies and frequency response planning

To contract fast response that would be needed to operate the NETS with lower system inertia, it will be important to inform control room engineers what to anticipate. System modelling will need to be used to identify the response expected from the wide area control system to a given frequency event and simulate and plan how to best coordinate with conventional response.

The DIgSILENT PowerFactory programming code developed by the University of Manchester to simulate different wide area control systems can be utilised to assess the impact of fast response on the network. Circuit and generation outages can be analysed in a PowerFactory model with this code to give a comprehensive view on how to operate the NETS at each implementation phase of the MCS.

As prerequists to fully unlocking the benefit and making use of the coordinated approach offered by the MCS, increased ability to model the dynamic system behaviour, along with greater visibility of real-time system measurements (including system inertia), is needed. This is especially important with lower inertia systems and potential within-day frequency response procurement strategies.

Commercial and operational requirements

New commercial applications, real-time operational data and measurement tools, and coordination with market mechanisms will be needed for the implementation of the MCS. These are outlined below:

i) frequency response auction platform[16]
ii) real-time system inertia measurement tool
iii) system performance monitoring and phasor measurement devices[17]
iv) wider access to the balancing mechanism[18] and ENTSO-E-Libra markets[19]

The MCS is dependent on having access to operational data of the system performance. As such, reliable and accurate system inertia values and real-time system performance data is fundamental to any potential use of the MCS within an operational environment. This will require continued development to improve NGESO capabilities and closer collaboration with network licensees in order to agree strategies and associated timescales.

The commercial framework to support the MCS coordinating fast frequency response will need to be fundamentally different from current arrangements. For instance, it will require access to a within-day frequency response auction platform to fully exploit the capabilities of weather-dependent service providers. This will also require access to enhanced settlement metering data to capture real-time response delivery. These increased capabilities will require industry consultation to ensure that the solutions developed meet the requirements of the MCS and market participants.

Implementation considerations for frequency response technologies

The trials carried out by the commercial partners in the project have shown that for technologies to deliver response using the MCS, site specific considerations need to be reviewed.

Site control systems and communications protocols

The trials have shown that the speed of the MCS response can be largely affected by the proprietary control systems that receive control commands from the LC, which could lead to inconsistent response times. Therefore, a minimum standard for site control systems is needed to facilitate the speed of response.

Several communications protocols to interface commercial sites with the LC have been tested. Of note for its limitations, is the MODBUS TCP/IP protocol used at the hybrid solar photovoltaic (PV) and battery storage site. Slower than anticipated response times were due to the TCP protocol (that checks the data that's exchanged between devices), and the communications link being shared by more than one client. As the communications topology in solar farms were not originally designed to be fast, retrofitting to incorporate dedicated communications links will be more effective for fast response.

RoCoF measurement and RoCoF settings in the MCS

The design of the MCS is based on real-time data from PMUs from which RoCoF is measured. An alternative method trialled at the Dynamic RoCoF demand side response site used Allen Bradley equipment to calculate RoCoF. This was shown to be a viable option for fast

[16] https://www.nationalgrideso.com/insights/future-balancing-services
[17] https://www.nationalgrideso.com/document/138506/download
[18] https://www.nationalgrid.com/sites/default/files/documents/Wider%20BM%20Access%20Roadmap_FINAL.pdf
[19] https://www.entsoe.eu/network_codes/eb/terre/

frequency response that could potentially be utilised at combined heat and power (CHP) sites. Further investigations need to be carried out to uncover other more cost-effective options to PMUs.

Frequency measurement noise was exhibited at some sites which can lead to spurious detections of frequency events. A solution was implemented that modified the event detection algorithm in the LC to prevent false detection, however filtering system frequency signals could be used, although it's effect on the performance of the MCS needs to be ascertained.

Different locations on the national electricity transmission system (NETS) can show different levels of RoCoF even if they are close geographically. This means that given the current design of the MCS, service providers will require various trip settings in the LC. To achieve the correct settings, initial monitoring at sites is necessary to understand the RoCoF behaviour at that location. Once the LC is operational, the settings may need to be changed (or 'tuned') to determine the best control system parameters. Further work to better understand how this tuning should be done or to develop an alternative strategy for the triggering response via the MCS needs to be reviewed.

Forecasting for renewable technologies
For renewable technologies to provide frequency response via the MCS, the NGESO will require visibility of the amount of MW that is available at each plant and what response has been delivered.

At the solar PV site, BELECTRIC has successfully developed and tested a forecasting technique with a high accuracy (95% for 15-minute forecast) that can be integrated with the MCS. Similar forecasting systems would be needed to ensure confidence in using solar for frequency response.

The wind trials undertaken during this project did not explicitly integrate forecasting with the MCS. However, a forecasting interface with the MCS would be required for predictable use of either de-loading and faster operation, or for using inertial response (IR) from wind. To use IR, forecasting will be critical to understand the MW 'boost' delivered and also the energy deficit during the wind turbine recovery period. The boost and deficit effects to the system can be optimised by altering the duration of the boost, which can be individually selected on each turbine. Consideration will need to be given to any variations to IR durations and timings that are staggered across all the turbines of the wind farm.

Learning dissemination

Dissemination of the EFCC project learnings focused on both external mechanisms to raise awareness with key stakeholders and audiences within the industry and internal dissemination within National Grid. The key mechanisms used throughout the project during 2018 and 2019 are listed below. For further dissemination details in 2017, 2016 and 2015, please see the project's progress reports on the EFCC project's website.[20] in the folder titled 6 monthly OFGEM reports archive.

Awards:

Award	Status
The 13th British Renewable Energy Awards 2018: 'Smart Energy Systems' Award.	Submission shortlisted as a finalist. Received 'highly commended' accolade.

Stakeholder events are summarised in Table 20 below:

Event	Date	Scope	Contribution type
ICMS Workshop	16-18 Jan-18	GE presented at the ICMS Management of Energy Networks conference	Presentation
Electricity System Change, Glasgow, UK	Jan-18	Flexitricity – promoted the role of demand side response in EFCC	Networking
Application of a Wide Area Monitoring and Control Technique for Fast Frequency Response lecture	Feb-18	UoM – Organised lecture	Lecture
The IET industry event: Application of a Wide Area Monitoring and Control Technique for Fast Frequency Response lecture	07 Feb-18	Team members from National Grid ESO, GE Renewable Energy, the University of Strathclyde and the University of Manchester shared the design, operation and tests of the EFCC scheme. They discussed potential market opportunities for the future of this project	Presentation
Project dissemination events	Mar-18 Cheltenham	The team has held its own stakeholder days, inviting delegates from across the energy industry. Each event has always hosted over 70 delegates. The events provided updates on the project and offered a 'deep dive' into the project's technical and commercial workstreams. The event generated significant amounts of useful feedback and prompted discussion among stakeholders about the project. Material from all the events has been uploaded to the project's website	Presentations, Q&As, discussions
Smart Energy, London, UK	Mar-18	Flexitricity – promoted the role of demand side response in EFCC	Networking
Future of Utilities, London, UK	Mar-18	Flexitricity – promoted the role of demand side response in EFCC	Networking
All Energy Conference, Glasgow, UK	May-18	Flexitricity – promoted the role of demand side response in EFCC	Networking

[20] https://www.nationalgrideso.com/innovation/projects/enhanced-frequency-control-capability-efcc

Edie Live, Birmingham, UK	May-18	Flexitricity – promoted the role of demand side response in EFCC	Networking
Exhibited at 'Innovation Week', National Grid House Warwick, UK	11 – 15 June 2018	Enhancing the profile of the project to internal NG audience exhibiting at Innovation Week	Exhibition stand
Project dissemination events	Jun-18 Glasgow	The team has held its own stakeholder days, inviting delegates from across the energy industry. Each event has always hosted over 70 delegates. The events provided updates on the project and offered a 'deep dive' into the project's technical and commercial workstreams. The events generated significant amounts of useful feedback and prompted discussion among stakeholders about the project. Material from all the events has been uploaded to the project website	Presentations, Q&As, discussions
Power Responsive Flexibility Forum	26 Jun-18	Power Responsive is a stakeholder-led programme facilitated by National Grid to stimulate increased participation in different forms of flexible technology, such as DSR and storage. The team exhibited at their conferences and shared project knowledge and learnings with the audience	Exhibition stand
ENA Electricity Forum	28 Jun-18	This was a joint dissemination event where Great Britain's distribution and transmission networks shared insights from their innovation work. As well as presentations, there was an opportunity to ask questions and network with innovation representatives from the electricity networks The EFCC project team shared the most up-to-date news from the project's commercial and technical work streams with network licencees	Presentation
Reduced Inertia Response in Power Systems by WAMPAC. IEEE Power and Energy Society, General Meeting (PESGM), Portland, USA	Aug-18	UoM presented	Presentation
Project webinars	25 Sept-18 Commercial webinar	Shared the results of the cost benefit analysis with the industry: 96 registered, 61 joined. Both webinars generated questions and discussion. A Q&A sheet was circulated after each webinar and published on the project website with the slides	Webinar
GE EMEA User Conference, Wembley	8-11 Oct-18	GE Renewable Energy discussed the MCS at this digital conference focusing on industrial software and services to enable the energy industry to become more efficient, reliable, secure and sustainable	Presentation
Power Responsive Flexibility Forum	23 Oct-18	Power Responsive is a stakeholder-led programme facilitated by National Grid to stimulate increased participation in different forms of flexible technology, such as DSR and storage. The team exhibited at their conferences and shared project knowledge and learnings with the audience	Exhibition stand
MEEPS 2018, IEEE Power and Energy Society (Monitoring of Power Systems)	02 Nov-18	UoM presented – A Wide Area Monitoring and Control System for Fast Frequency Response	Presentation

Low Carbon Networks and Innovation (LCNI) Conference	2018 Telford	This event is the only conference dedicated to showcasing the breadth of innovative engineering work taking place across the networks to deliver the UK's energy future with network licencees	Exhibition stand demonstrated an overview of the project using video. The project manager presented updates from the previous conference
8th International Conference on the Integration of Renewable and Distributed Energy Resources	2018	UoS – poster presentation: 'Validating decentralised frequency control regimes: a distributed hardware-in-the-loop approach'	Poster presentation
Project webinars	05 Feb-19 Wind, solar and battery webinar	Shared the most up-to-date wind and solar results following trials:101 registered, 47 joined The webinar generated questions and discussion. A Q&A sheet was circulated after the webinar and published on the project website with the slides	Webinar
CIGRE Technical webinar	13 Feb-19	The EFCC project featured on the CIGRE webinar which shared an overview of the project and its objectives. The audience were mostly network licencees	Presentation
Final project dissemination event	01 May-19	This webinar summarised the key findings in this report for attendees: 51 registered, 28 joined Slides from the webinar can be downloaded on the project's website.	Presentation

Table 20: Stakeholder events attended by the project team

Publications:

Publication name	Author	Date
Alstom – Control Platform Specification Summary	GE Renewable Energy	Oct-15
Alstom Grid – *Event Detection SMART Frequency Control*	GE Renewable Energy	Oct-15
General Electric Grid Solutions – Smart Frequency Control – Resource Allocation Application	GE Renewable Energy	Nov-15
Published paper *A New Inertia Emulator and Fuzzy–Based LFC to Support Inertial and Governor Responses using Jaya Algorithm* 2016 IEEE Power and Energy Society, General Meeting (PESGM),Boston, USA	R. Azizipanah-Abarghooee, M. Malekpour, M. Zare, V. Terzija	Jul-16
Smart Frequency Control for the Future GB Power System. 2016 IEEE PES Innovative Smart Grid Technologies Conference Europe.	P. Wall, N. Shams, V. Terzija, V. Hamidi, C. Grant, D. Wilson, S. Norris, K. Maleka, C. Booth, Q. Hong, A. Roscoe	Oct-16
Control of an electrical power network WO2016174476A3, 03	D. Wilson, O. Bagleybter, S. Norris, and K. Maleka	01 Nov-16
Advances in Wide Area Monitoring and Control to address Emerging Requirements related to Inertia, Stability and Power Transfer in the GB Power System, Paper C2-208-2016	Wilson D.H., Clark S., Norris S., Yu, J, Mohapatra P., Grant C., Ashton P., Wall P., Terzija V	2016 Cigre Session, Paris, France
Smart frequency control for the future GB power system – IEEE PES Innovative Smart Grid Technologies Conference Europe (ISGT-Europe), Ljubljana, pp. 1-6	P. Wall, N. Shams, V. Terzija, V. Hamidi, C. Grant, D. Wilson, S. Norris, K. Maleka, C. Booth, Q. Hong, A. Roscoe	2016

Conference paper at 2016 IEEE PES Innovative Smart Grid Technologies Conference Europe: *Smart frequency control for the future GB power system*	UoS	2016
Published journal paper *A New Centralised Adaptive Under-Frequency Load Shedding Controller for Microgrids based on a Distribution State Estimator*	M. Karimi, P. Wall, H. Mokhlis, V. Terzija	Feb-17
Published paper *Smart Integrated Adaptive Centralized Controller for Islanded Microgrids under Minimized Load Shedding. ICSG 2017, Istanbul Turkey*	M. Karimi, R. Azizipanah-Abarghooee, H. Uppal, Q. Hong, C. Booth, V. Terzija	Apr-17
Published paper *A Centralised Under-Frequency Load Shedding Controller based on State Estimator for Microgrid Applications. Relay Protection and Automation for Electric Power Systems 2017,Saint-Petersburg*	M. Karimi, P. Wall, H. Mokhlis, V. Terzija	2017
Conference paper at the 2017 IEEE PES Innovative Smart Grid Technologies Conference Europe: *Application of a MW-Scale Motor-Generator Set to Establish Power-Hardware-in-the-Loop Capability*	UoS	2017
Conference paper at 2017 IEEE International Workshop on Applied Measurements for Power Systems: *Validation of algorithms to estimate distribution network characteristics using power-Hardware-in-the-Loop configuration*	UoS	2017
Conference paper at 2017 5th International Istanbul Smart Grids and Cities Congress and Fair: *Smart integrated adaptive centralized controller for islanded microgrids under minimized load shedding*	UoS	2017
Conference paper at 13th IET International Conference on AC and DC Power Transmission: *Studies of dynamic interactions in hybrid ac-dc grid under different fault conditions using real time digital simulation*	UoS	2017
Published paper *Modelling DFIG Based System Frequency Response for Frequency Trajectory Sensitivity Analysis. International Transactions on Electrical Energy Systems Journal*	R. Azizipanah-Abarghooee, M. Malekpour, Y. Feng, V. Terzija	Jun-18
Accepted paper *A New Approach to the Online Estimation of the Loss of Generation Size in Power Systems. IEEE Transactions on Power Systems Journal*	R. Azizipanah-Abarghooee, M. Malekpour, M. Paolone, V. Terzija	Jul-18
Revised paper *An Explicit Formulation for Synchronous Machine Model in Terms of Manufacturer Data. International Journal of Electrical Power and Energy Systems*	R. Azizipanah-Abarghooee, M. Malekpour, M. Zare, A. Kiyoumarsi, V. Terzija	Jul-18
IEEE Spectrum magazine	GE Renewable Energy, UoS	19 Sept-18
Published paper *Trajectory Sensitivity Analysis of Rate of Change of Frequency Using System Frequency Response Model. 2018 IEEE Power and Energy Society, Innovative Smart Grid Technologies Conference Europe, Sarajevo, Bosnia*	R. Azizipanah-Abarghooee, M. Malekpour, N. Shams, M. Karimi, V. Terzija	Oct-18
Published paper *Small Signal Based Frequency Response Analysis for Power Systems. 2018 IEEE Power and Energy Society, Innovative Smart Grid Technologies Conference Europe, Sarajevo, Bosnia*	R. Azizipanah-Abarghooee, M. Malekpour, M. S. Ayaz, M. Karimi, V. Terzija	Oct-18

Fast frequency response for effective frequency control in power systems with low inertia, pp. 1–8	Q. Hong, M. Nedd, S. Norris, I. Abdulhadi, M. Karimi, V. Terzija, et al.	2018
Design and Validation of a Wide Area Monitoring and Control System for Fast Frequency Response – IEEE Transactions, in review at time of writing	Q. Hong, M. Karimi, M. Sun, S. Norris, O. Bagleybter, D. Wilson, I. Abdulhadi, B. Marshall, V. Terzija and C. Booth	2018
Journal paper submitted to IEEE Transactions on Smart Grid: *Design and Validation of a Wide Area Monitoring and Control System for Fast Frequency Response*	UoS	2018
Journal paper submitted to IEEE Transactions on Industrial Electronics: *Realisation of High Fidelity Power-Hardware-in-the-Loop Capability Using a MW-Scale Motor-Generator Set*	UoS	2018
Conference paper submitted to International Conference on Smart Grid Synchronized Measurements and Analytics: *Review of Approaches for Using Synchrophasor Data for Real-Time Wide-Area Control*	UoS	2018
Conference paper at the 14th IET International Conference on AC and DC Power Transmission: *Fast frequency response for effective frequency control in power systems with low inertia*	UoS	2018

Website

The project has a bespoke website[21] which has been a key tool in disseminating material. The project has a dedicated email address to enable stakeholders to get in touch with the project team easily (box.EFCC@nationalgrid.com).

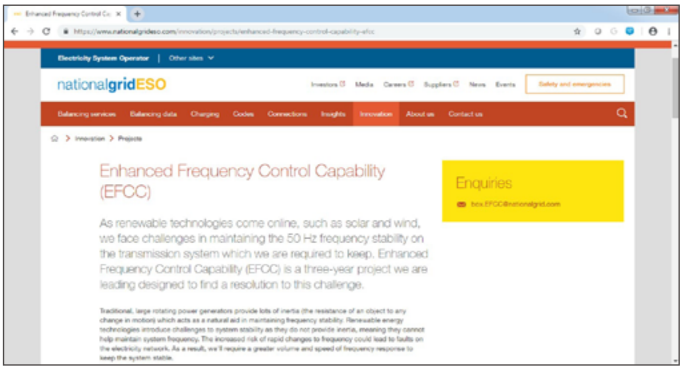


Figure 55: The EFCC project website

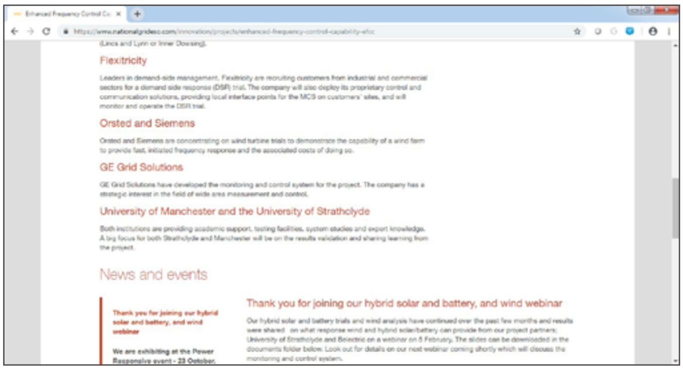


Figure 56: The EFCC project website

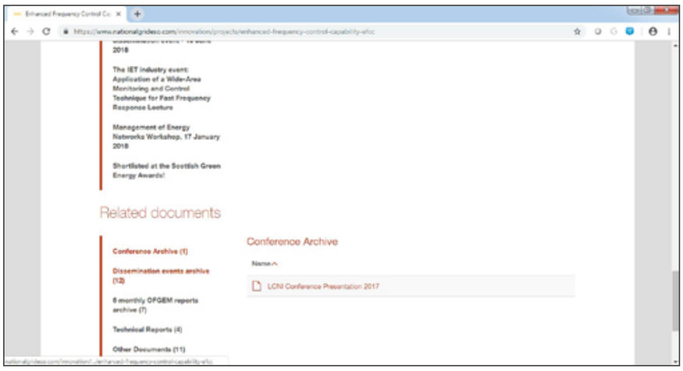
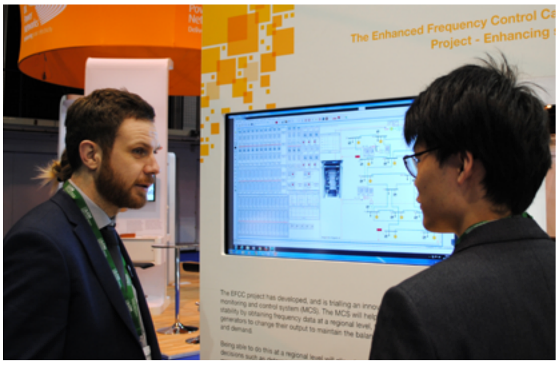


Figure 57: The EFCC project website

[21] https://www.nationalgrideso.com/innovation/projects/enhanced-frequency-control-capability-efcc

Left - Members from the EFCC project team at the 13th British Renewable Energy Awards where the project received a 'highly commended' accolade.

Above - The project's dissemination event in Cheltenham, March 2018.



Left - Members from the EFCC project team at the Low Carbon Networks and Innovation Conference, December 2017

Table 21 below shows there has been a spike in the number of visits to the website during the project. In 2016 and in 2017, in line with business brand guidelines, the website had new URL addresses to reflect changes happening in the business. The spike could have been triggered by specific activity such as:

- sharing the web link in email signatures
- ad hoc specific project update emails to our mailing list directing people to the web page
- including the website address on project leaflets issued at events
- including our email address on pull-up banners used at stakeholder events such as Power Responsive.

Year (from March to March)	Views (how many times the pages has been viewed)	Unique views (how many individuals have visited the page)
2015/16	Figures cannot be provided as analytics were not available during this time and the website URL is no longer accessible.URL was http://www.nationalgridconnecting.com/The_balance_of_power/	
2016/17	38,239	29,739
2017/18 (old web address) www.nationalgrid.com/EFCC	15,534	13,436
2017/18 (new web address) https://www.nationalgrideso.com/innovation/projects/enhanced-frequency-control-capability-efcc	3,437	2,649
2018/19	8,853	6,933

Table 21: Number of visits to the EFCC project website

Feedback from stakeholders

Throughout the project, we have welcomed feedback from stakeholders. We have captured this feedback through discussions on exhibition stands, at our stakeholder events, and after project webinars, to name a few. We have created a FAQ document which was updated as the project progressed. The project's wind, solar and battery results webinar, which took place in February 2019, generated more questions. A second FAQ document was created, issued to our mailing list and published on the project's website. The project's email address has always been promoted as an easy way to actively submit feedback and we have responded quickly to any emails that have landed.

Key learning documents

Below is a summary of the reports that have been produced to share learning. They can be downloaded from the project's website.

Published technical reports
Table 22 below lists the technical reports that are available on the EFCC project website.

Report title	Report description	Author	Date
National Grid's Battery Storage Investigation Report June	This report summarises the investigation into the use of existing battery storage facilities for the Enhanced Frequency Control Capability (EFCC) project	National Grid ESO	Jun-15
Control Platform Specification Summary	This report outlines the requirements and functionality of the MCS. It includes an overview of the chosen hardware and the platform's software architecture	Alstom (now GE Renewable Energy)	Oct-15
Smart Frequency Control Resource Allocation Application	This report follows the first release document describing event detection in NG-EFCC-SPEC040. It will build on the development described in the earlier document	GE Renewable Energy	Nov-15
National Grid's Battery Storage Investigation Report November	This report summarises the investigation into the use of existing battery storage facilities for the Enhanced Frequency Control Capability (EFCC) project	National Grid ESO	Nov-15
GE Optimisation Detailed Design	Optimisation of service providers within the MCS dependent on their response characteristics	GE Renewable Energy	Jan-16
Solar PV	This document evaluates the performance of solar PV systems using the MCS	BELECTRIC	Mar-18
EFCC Wind Package Report Frequency Support Outlook	Summary of Burbo Bank wind farm's capabilities for fast-acting frequency support. Probabilistic analysis of inertial response on wind farm output across GB	Ørsted	Jun-18
Large Scale Thermal Generation	This outlines the methodology and testing of RoCoF-based frequency response from a gas turbine	Centrica/EPH	Jun-18
UoS - Part 1 Local Operational Mode Technical Report	This report presents the methods and results of tests conducted at the University of Strathclyde's Power Network Demonstration Centre (PNDC) for validating the monitoring and control scheme	University of Strathclyde (UoS)	Jul-18
UoS - Part 2 Wide Area Mode Tests Technical Report	This document is the first part of the overall final test report and presents the results from the first stage tests that evaluated the MCS performance when operating in local mode	UoS	Jul-18

Table 22: The technical reports that are available on the EFCC project website

Demand Side Response Technical Report	This report summarises Flexitricity's role in the project and their conclusions	Flexitricity	Oct-18
UoS - Part 3 Communication Technical Report	This report is the third of three reports (listed above). The other two reports focus on testing the MCS in local and wide area operational modes	UoS	Nov-18
MATLAB Hybrid Model Internal report	This report presents methodologies and simulation tests of different wide area control methods and their application for frequency containment	BELECTRIC	Nov-18
UoS – Additional Local Operational Mode Testing Technical Report	This report provides results from additional testing of the impact of the signal filters in the local controllers (LCs) for RoCoF measurements	UoS	Mar-19
UoS – System studies for demonstrating the capabilities of inertial response from wind farms	This report describes network analysis of the impact of inertial response	UoS	Mar-19
RTDS HiL-testing to assess the entire monitoring and control system (MCS) for EFCC	This document shows analysis that tested the functionality of the entire MCS using GB equivalent RTDS model by Hardware-in-the-Loop test, implemented on the hardware platform using the PLC environment	UoM	2018
PV-Battery Hybrid System – Test Report	This report evaluates the performance of the PV-Battery Hybrid System running the EFCC control and monitoring scheme and highlights the scheme's benefits and advantages as well as drawbacks/ limitations that might impede its working	BELECTRIC	Feb-19
Impact assessment of the MCS on operational systems	MCS data process analysis and impact assessment on National Grid ESO systems	National Grid ESO	Jun-19
Modelling and Study of Wide Area Control Methods using 36-Zone GB Model in PowerFactory	This report presents methodologies and simulation tests of different wide area control methods and their application for frequency containment	UoM	Jun-19

Table 22: Published EFCC technical reports

Chapter 13

Non published technical reports
Some of the technical reports produced during the project contain sensitive data associated with intellectual property rights. Table 23 shows the reports that have been produced, but could not be published because they contain sensitive data associated with intellectual property rights.

Report title	Report description	Author	Date
Event Detection SMART Frequency Control (EFCC)	This document describes the principles behind the event detection algorithms developed for the project. The report describes results of the algorithm when used with simulated test cases	GE Renewable Energy	Apr-15
Control Platform Specification Summary	This document outlines the requirements and functionality of the controller platform. It also contains an overview of the chosen hardware and the platform's software architecture	GE Renewable Energy	Apr-15
Resource Allocation Design Document	This document covers the design phase of the Resource Allocation application	GE Renewable Energy	Aug-15
Test Report Control Platform Testing	This document discusses the control scheme being developed for the SFC project. This includes a hardware platform and Application Function Blocks (AFBs)	GE Renewable Energy	Sept-16
SFC Controller FAT procedure	This document contains the FAT procedures designed to both verify and exercise the controller designed for the SFC project, including the Phasor Data Concentrator (PDC), controller devices and visualisation	GE Renewable Energy	Oct-16
Data Review and Performance report	This report presents the results from the field trials and overall performance of the Enhanced Frequency Control Capability (EFCC) scheme to date, and an evaluation of the PMU and EFCC controller performance	GE Renewable Energy	Mar-17 (updated in Jun-19)
SFC Revision Report Control Platform	This report presents the results from the field trials and overall performance of the Enhanced Frequency Control Capability (EFCC) scheme to date, and an evaluation of the PMU and EFCC controller performance. This report to project partners describes the revisions to the PhasorController (PhC) software platform, which was released in August 2016	GE Renewable Energy	Jul-17
Wind Turbine Tests of SWT – 7.0 – 154 Inertial Response	This document summarises Inertial Response (IR) tests on a wind turbine type SWT-7.0-154	Siemens Gamesa Renewable Energy	Mar-18
Extended Inertia Response Performance for a D3 + D7	This document shows the expected performance of extended inertia response	Siemens Gamesa Renewable Energy	Aug-18

Table 23: EFCC technical reports not published to to restrictions on intellectual property rights.

Chapter 13

The project team had to provide a detailed Project Progress Report (PPR) for Ofgem throughout the project. This report contains enough detail for Ofgem to evaluate the progress of the project. Once submitted, these were published on the project website.

Project progress reports
Table 24 summarised the 6-monthly reports published by NGESO which provided regular project updates.

Report title	Date
6-monthly progress report	January – June 2015
6-monthly progress report	July – December 2015
6-monthly progress report	January – June 2016
6 monthly progress report	July – December 2016
6-monthly progress report	January – June 2017
6-monthly progress report	July – December 2017
6-monthly progress report	January – June 2018

Table 24: EFCC progress reports

Chapter 14

Useful information

Data access details

Network licensees must tell anyone who is interested how they can request network or consumption data gathered during a project. From 30 September 2017, network licensees must have a publicly available data sharing policy setting out the terms on which such data will be provided. National Grid ESO's data sharing policy, relating to Network Innovation Allowance (NIA) and Network Innovation Comptition (NIC) projects, can be found **here**.

Ofgem expects network licensees to share network and consumption data if the person requesting it can show it is in consumers' interests to do so. Data may be anonymised and/or redacted for commercial confidentiality or other sensitivity.

Contacts details

For more about the EFCC project, please contact NGESO via: box.EFCC@nationalgrid.com

Accuracy Assurance Statement

This EFCC project closing down report has been produced in agreement with the entire project steering committee. All project partners have been involved in writing and reviewing it. The report has been approved by the EFCC project steering committee and by Graham Stein, Network Operability Manager, on behalf of Craig Dyke, Networks Manager and the Project Sponsor at National Grid ESO. Every effort has been made to ensure that all information in the report is true and accurate.

Signed:

Graham Stein

This report has also been peer reviewed by colleagues at Western Power Distribution and SP Energy Networks.


29
33
37
41
45
Initial Forecast Value
SP
Original (MW)
1
2
5360
NULL

Project Partners

National Grid Electricity System Operator (NGESO) partnered with eight energy experts and academia to deliver this project:

Work Package 2.3: Assessment of the response of different providers – Solar PV
Solar power experts BELECTRIC provided response from photovoltaic (PV) power plants and battery storage facilities. They have contributed knowledge and practical solutions to realise the project's goals concerning battery and PV-based frequency regulation.

Work Package 2.2: Assessment of the response of different providers – Large Scale Generation
Multinational utility business Centrica/EPH provided simulation evidence to demonstrate the viability of large scale thermal generation to provide faster frequency response by implementing revised frequency control logic.

Work Package 2.1: Assessment of the response of different providers – demand side response
Leaders in demand-side management, Flexitricity, recruited customers from industrial and commercial sectors for demand side response (DSR) trials. The company also used its proprietary control and communication solutions providing local interface points for the monitoring and control system (MCS) on customers' sites, and monitored and operated the DSR trial.

Work Package 2.5: Assessment of the response of different providers – Wind
Ørsted (previously known as DONG Energy) and Siemens Gamesa Renewable concentrated on wind turbine trials to demonstrate the capability of turbines to provide fast initiated frequency and inertial response.

Work Package 1: Developing and testing the monitoring and control system
GE Renewable Energy (previously known as Alstom Psymetrix) developed the monitoring and control system (MCS) for the project. They are a leading provider of synchrophasor based wide area management systems (WAMS), services and support for the energy industry.

Work Package 3: Optimisation (University of Manchester)
Work Package 4: Validation (University of Manchester and Strathclyde)
Both universities provided academic support, testing facilities, system studies and expert knowledge. They focused on testing the robustness and performance of the MCS, investigated different wide area control methods for system frequency containment, and sharing project learnings.

Appendix B

36-bus and 26-bus system models

The National Grid Electricity System Operator (NGESO) provided the Universities of Manchester and Strathclyde with a DIgSILENT PowerFactory model to carry out system studies with and without the monitoring and control system (MCS). The model is a simplified representation of the Great Britain (GB) electricity transmission system which can be used to dispatch different generation and demand levels and simulate future energy scenarios.

36-bus system model

Figure 58 below shows the 36-bus (zones) and their representative locations across GB.

Each bus (node) in the model represents a generation and demand site. The types of generation in the model are combined cycle gas turbines (CCGT), nuclear, biomass, hydroelectric and pumped storage plants, as well as several interconnectors.

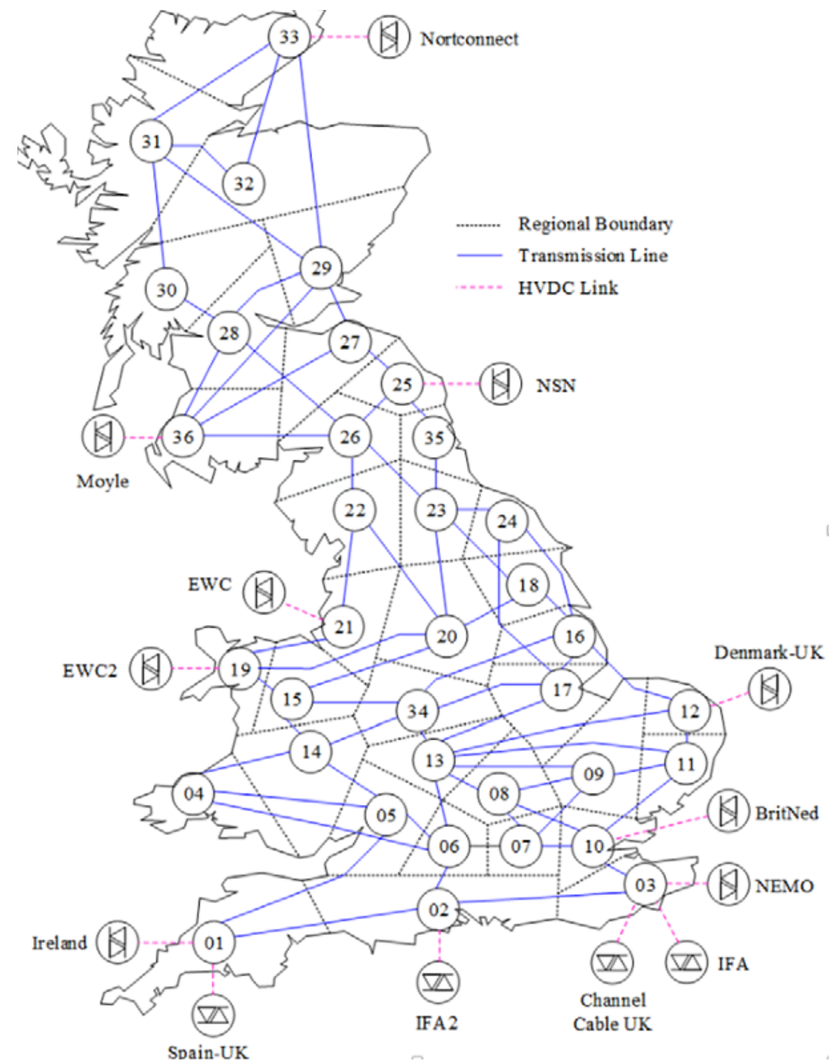


Figure 58: 36-bus model of the Great Britain electricity transmission system

Appendix B

26-bus system model

An alternative, reduced electricity transmission system model was developed by the University of Manchester for implementation to use in its Real Time Digital Simulator (RTDS) environment because of the equipment's computational limitations. This model (as illustrated in Figure 59), was derived from the 36-bus version above and validated to make sure the results were comparable.

As in the 36-bus model, each bus represents a generation and demand site with the same types of generation modelled. Added to this, the University of Manchester included dedicated models for solar photovoltaic (PV), wind turbines, CCGT and demand side response (DSR) plant so they could be independently controlled and tested with the MCS in the Hardware-in-the-Loop environment.

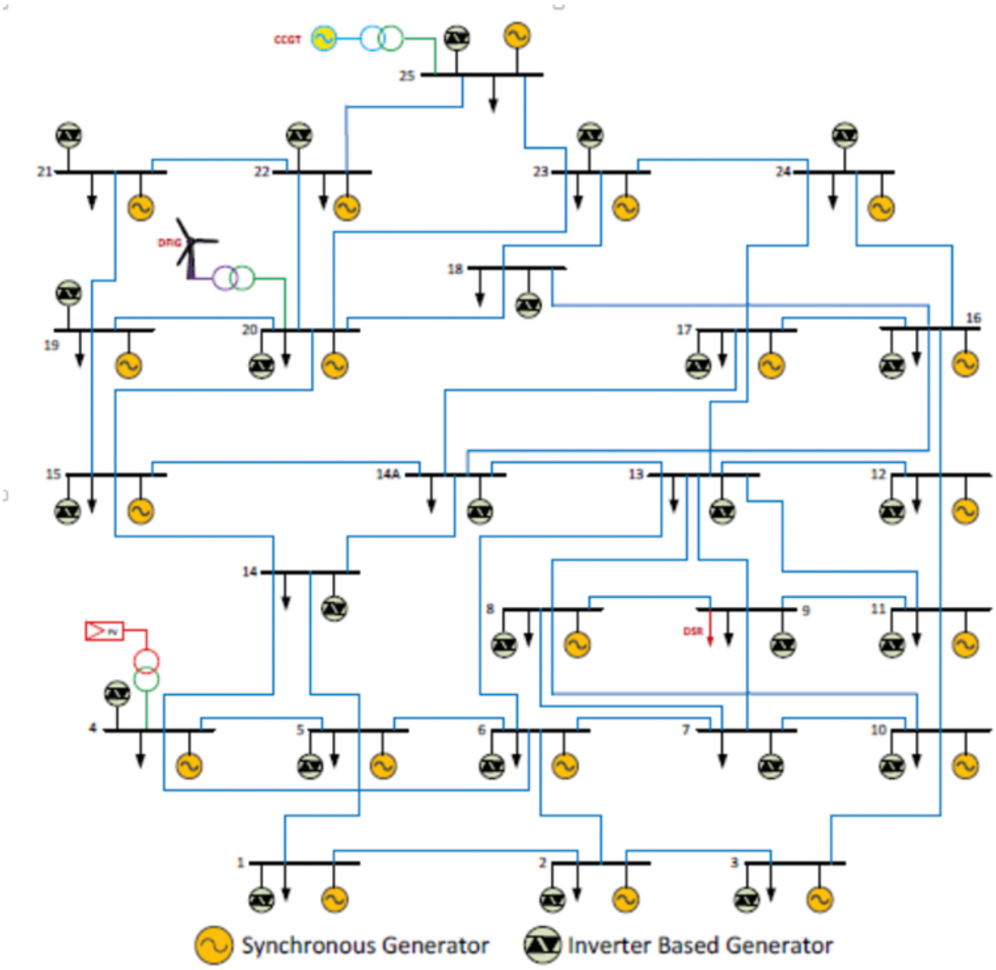


Figure 59: Diagram of 26-bus model of the GB electricity transmission system

Appendix C

Monitoring and control system technical development and specification

Data flow at system level

The data structure for the wide area measurement scheme is shown in Figure 60. Voltage phasors and frequency measurements are collected from a defined set of phasor measurement units (PMUs) across a region. At these locations, PMUs will send data directly to the Regional Aggregator (RA). The output streams of the RAs will be communicated over a dedicated network. Each Local Controller (LC) is configured to receive the streams from each of the RAs allowing the full system conditions to be seen. The LC knows which region it belongs to, but can also receive local measurement data from a locally installed PMU. Each new controller-resource pair deployed is connected onto this network as shown by the connection points in Figure 60.

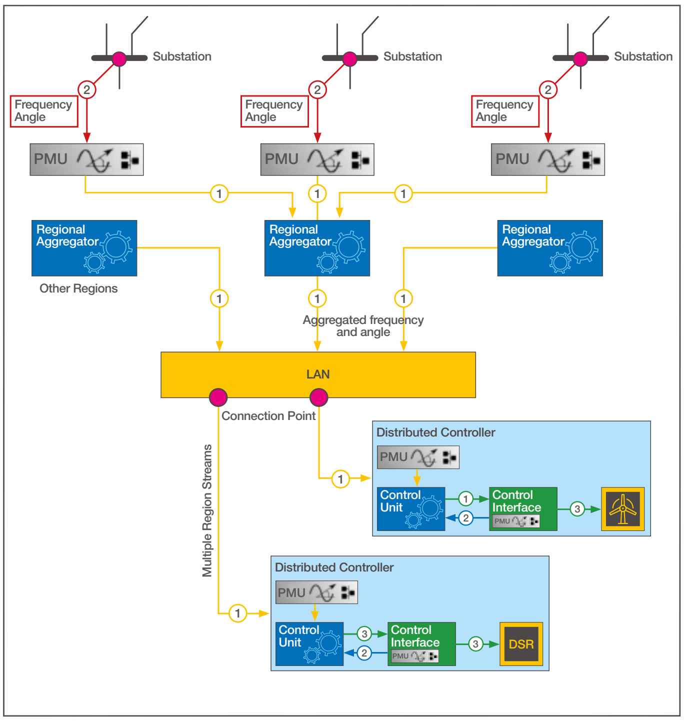


Figure 60: A PMU communication and data flow for the MCS

Data flow at local level

The LC can be installed close to a resource and will receive data from the resource, data from the RAs and data from a Central Supervisor (CS) (not shown in Figure 60). Figure 61 shows an example installation at a service provider. The LC must receive information from the resource, either directly through a control protocol, or indirectly via the local PMU, for example. The control platform developed is able to incorporate a range of standard protocols for this information exchange.

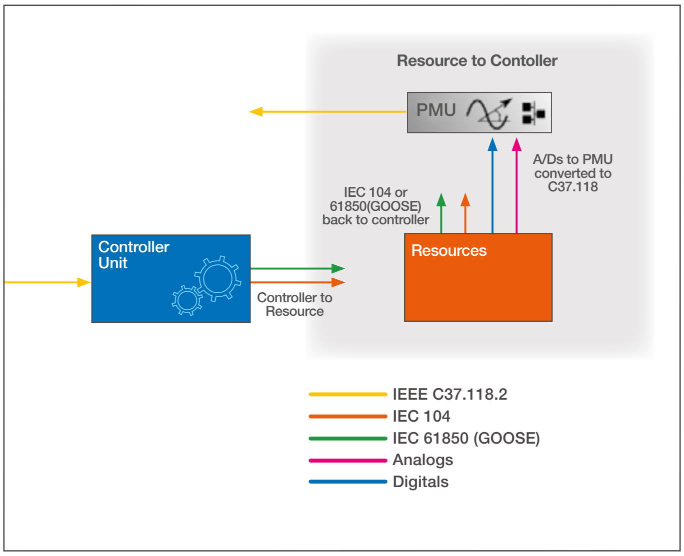


Figure 61: Controller to resource data

Technical specification

The following sections summarise the specification and architecture.

- Hardware
  The PhasorController (PhC) hardware is an enclosure containing a single-board computer. The single board computer is a quad core CPU with up to 1.2GHz, 1GB RAM and 1GB Flash disk. One Ethernet controller of the CPU is connected to the 100BaseT (RJ45) admin port, through which the PhC will be configured during commissioning. The remaining four CPU Ethernet controllers are connected via three, three-port Ethernet switches and one FPGA to small form factor pluggable (SFP) sockets which, for example, can be populated with 100FX Fibre SFPs.

- Electrical interfaces
  Table 25 outlines the electrical connections for the PhC platform.

Type	Connector	Quantity	Role
Ethernet (IEEE 802.3u): 100 Mbit/s over 100base-TX (2 wire-pairs)	RJ45	1	User-control and reporting (SSH/MMS)
Ethernet (IEEE 802.3u): 100 Mbit/s over 100base-FX (2-strand optical fibre) or 100base-TX (2 wire-pairs)	SFP	1	IP-based C37.118 synchrophasor i/p & o/p
Ethernet (IEEE 802.3u): 100 Mbit/s over 100base-FX (2-strand optical fibre) or 100base-TX (2 wire-pairs)	SFP	1	IEC 61850 GOOSE or IEC 60870-5-104

Table 25: Electrical interfaces of the PhC platform

- **Software platform and operating system**
  The PhC platform is built on a Linux co-kernel operating system. Figure 62 below illustrates the software platform and applications.

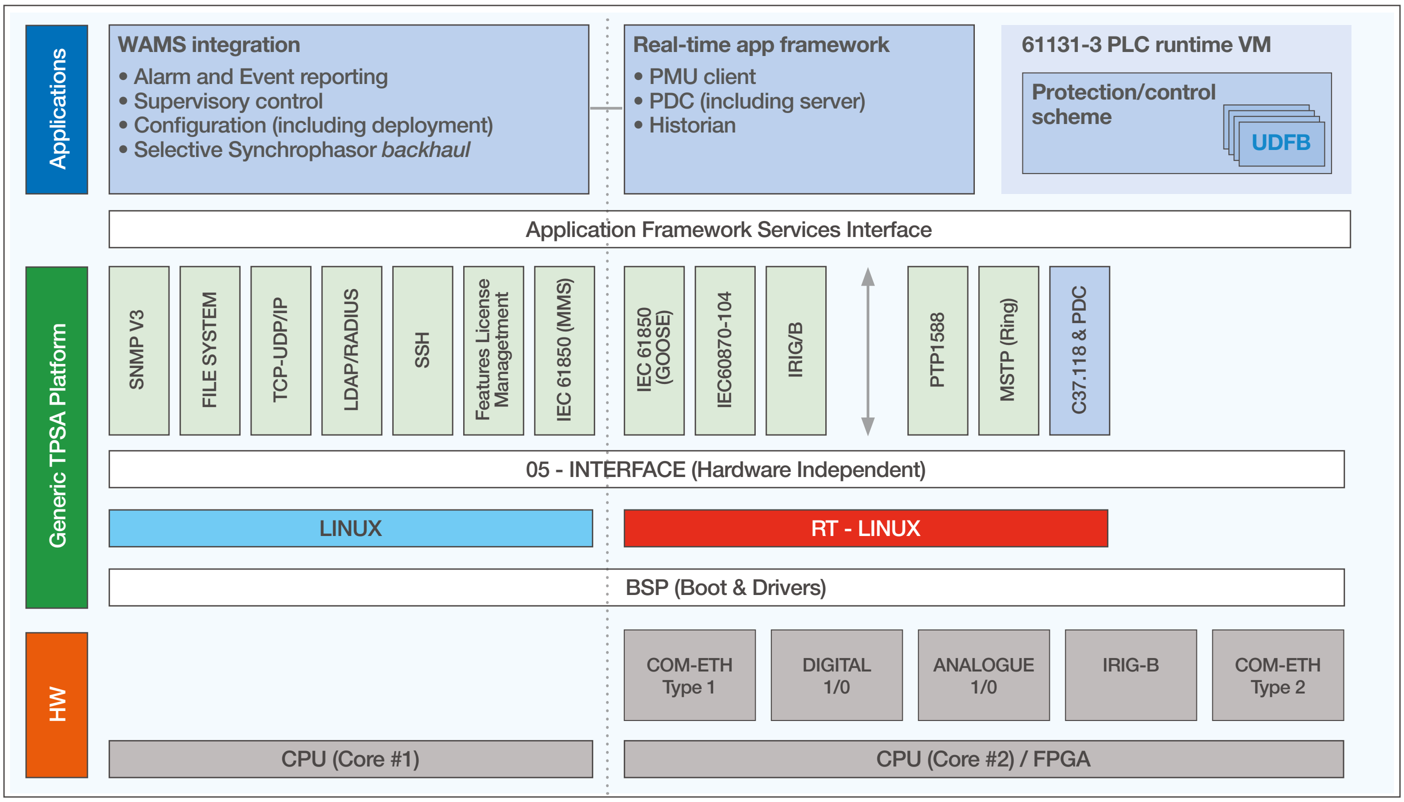


Figure 62: Software and applications used by the PhasorController

- **Protocols**
  Table 26 below lists the protocols supported by the PhC platform.

Type	Supported protocols
Network stack	IPv4 and IPv6, TCP, UDP, DHCP, FTP/SFTP, SSH, HTTP
Wide area network (WAN) synchronisation	PTP IEEE 1588-2002 (deferred to a later version)
Synchrophasor	IEEE C37.118-2014
Application protocols	IEC 61850 (2003-2004) GOOSE inputs and outputs, IEC 61850 MMS (deferred to a later version), IEC 60780-5-104

Table 26: Communication protocols supported by the PhC platform

- Application framework
  Synchrophasor analysis and control output generation are implemented by Programmable Local Controller (PLC) applications, each comprising a network of application function blocks (AFB)s. The PLC program execution environment will integrate user-configurable supporting functions that map external inputs and outputs (i/os) to PLC program i/os and perform functions such as synchronisation, time-alignment and buffer management.

- Configuration
  The configuration of a PhC for a specific deployment involves editing one or more plain text resource files. Resource files consist of pairs of resource names and values that the PhC will typically read at start-up. This mechanism is used to configure the control application with configuration settings such as a PMU's IP address, a PMU-id, an IED's Ethernet MAC address and other settings required by the specific control application.

- Performance
  The PhC platform is able to sustain continuous reception of the maximum number of C37.118 synchrophasor streams without any input data loss after being received by the PhC – except when it is taken offline for maintenance or power outage.

  The maximum latency from a generic objective orientated substation event (GOOSE) input to a GOOSE output shall be ≤ 20ms[22].

- User interface
  Remote access to the PhC may be required to:
  - implement supervisory control actions (start, stop, etc.)
  - allow live status indications review and retrieve log files
  - retrieve (upload), edit and replace (download) configuration files
  - replace software components.

  The PhC may not provide a graphical user interface (GUI). Command-line-level remote access may be achieved over a secure shell (SSH) console. File transfer capabilities may be provided with secure protocols such as SCP/SFTP.

- Data logging
  The PhC will provide data logging functions to help retrospective analysis of the PhC's response to an input scenario. This may improve the understanding of the scenario and/or reveal deficiencies of PLC programs or other software components.

  Non-volatile (Flash) memory and volatile RAM are more limited on the PhC than on a desktop PC or server. The PhC does not have access to a disc drive and may not have continuous network access to a remote (disc) share.

  The PhC will textually log significant events to a log-file in Flash. These events could include PLC program input and output events and PhC platform errors/warnings, for example relating to resource exhaustion. If the log-file reaches a configurable maximum size, the oldest entries will be deleted to enable log entries to be appended.

  The PhC will manage a volatile circular buffer of C37.118 synchrophasor input data. When a 'significant event' is detected, the PhC will copy a configurable amount of recorded input data to non-volatile storage before and after the event. Although no long-term record of the inputs from the power system is retained, this mechanism should be sufficient for the purpose stated above.

Control platform development
The proposed architecture and algorithms were implemented on a controller platform that needed to be installed in a power system, communicate using wide area protocols and instruct fast control commands. To achieve this, a new flexible control platform was developed by GE Renewable Energy to enable the development undertaken in the project to be deployed in a live system.

The PhC is a hardware platform that can be deployed within a power system as a central part of wide area monitoring protection and control (WAMPAC) applications. In such applications, PhCs will typically analyse synchrophasor measurements received from multiple PMUs and/or PDCs (Phasor Data Concentrators) to produce one or more binary trip or analogue control signals.

PhC platform objectives
The objectives for the PhC control platform were to provide:
- a high-performance, real-time synchrophasor analyser with very short response latencies
- an IEC 61131-3 PLC engine capable of running customer-designed applications (i.e. applications that are not simply configured by GE Renewable Energy for a given deployment but with functionality that can be tailored by the customer after initial deployment)
- GE Renewable Energy's AFBs to customers for inclusion in either complete GE Renewable Energy applications or bespoke/tailored applications
- the ability to interconnect multiple PhCs to form an integrated WAMPAC system
- the ability to accept high-level management control and report the controllers' state and actions for supervisory oversight; and
- provide the interfaces needed to integrate the PhC into a substation environment, as specified in IEC 61850.

[22] This latency will be met irrespective of the actual number of phasor streams consumed by a PLC program. The maximum latency from a C37.118 input to a GOOSE output will be ≤ 40ms. This latency will be met irrespective of the actual number of phasor streams consumed by a PLC program. The latencies above will be met only when no delay is applied by AFBs within the PLC scheme.

High level requirements

The high level requirements are that the PhC control platform will:

- receive up to 30 synchrophasor streams, encoded in C37.118 format, from one or more PMUs and/or PDCs. Each PDC stream may contain up to 10 PMU measurement sets. Each C37.118 stream will have a configured frame rate of 50fps, so a PhC can handle up to 300 PMUs in total
- continuously analyse C37.118 synchrophasor streams and produce outputs as determined appropriate by the application, typically within a single synchrophasor cycle (i.e. 20ms at 50Hz)
- include an IEC 61131-3 PLC engine capable of running customer-designed applications
- enable modifications of the PLC programs using a configuration tool when deployed within one or more PhCs. Typically, this may involve editing function block diagrams (FBDs). PLC programs implemented in the form of an FBD may include:
  - application function blocks (AFBs)
  - standard function blocks (FBs) provided by the configuration tool
  - custom FBs implemented as structured text (ST).
- provide the capability for PLC applications to accept high level management control from a supervisory WAMS. The PhC may provide the capability to report its state and actions to a WAMS to enable supervisory oversight. If required, these capabilities will be implemented using the IEC 61850 MMS protocol. At initial deployment, MMS control and reporting may not be provided. Instead a simple remote terminal session may provide sufficient access for high level management control and logging
- accept control inputs from micro-processor based devices and issue control outputs using IEC 61850 GOOSE frames and IEC 60870-5-104 protocol
- be capable of ‘real-time’ control i/o (input/output) and supervisory control and monitoring using Modbus.

When deployed, a PhC will provide limited analogue and digital/binary inputs and outputs.

MCS testing regime before site deployment

After the monitoring and control system (MCS) algorithms and hardware were developed, GE Renewable Energy tested and installed it at various locations so the universities and industry partners could carry out performance validation and commercial trials. The testing process is described below.

Testing

The algorithms and platform were extensively tested by GE Renewable Energy at the end of development to make sure all features operated correctly, verify that all requirements had been met and to test reliability and robustness of the scheme from the system level to application level. This included comprehensive white-box testing (i.e. all internal structures and designs are known to the tester) on the algorithms, and black-box testing on the controllers running the various application function blocks. Any issues identified were resolved and when all tests were passed, the system was ready to hand over to the project partners.

Factory acceptance testing

As part of the handover to project partners, a complete factory acceptance test (FAT) was performed and witnessed by project partners. This was a key milestone for the project as it validates to the customer that they are receiving what has been outlined in the scope of works. The FAT included a small-scale setup of the MCS driven from a simulator where all features of the control scheme were tested using physical hardware.

The only component not available in a FAT was the live measurements from a power system. Therefore, recorded data was injected into the scheme instead of the live power system data. The pre-recorded data includes event data, allowing the detection and deployment algorithms to be tested in the factory environment.

Site acceptance testing and deployments

After being tested by GE Renewable Energy, the MCS was deployed into the university test laboratories and commercial partner field trial sites. This was done according to partners' readiness for installation. At each partner site, GE Renewable Energy was involved in commissioning the MCS. The universities and National Grid Electricity System Operator (NGESO) each had multiple controllers, while field trial partners only installed Local Controllers (LCs). When commissioning was complete, a site acceptance test (SAT) was carried out to make sure the hardware installed was operating correctly on site and working with all necessary equipment such as phasor measurement units (PMUs) and the controllable resources. The following installation and SATs were performed:

- University of Manchester (February 2017)
- University of Strathclyde – Power Networks Demonstration Centre (February 2017)
- BELECTRIC (March 2017)
- Flexitricity (October 2017)
- Centrica/EPH (November 2017)
- NGESO (August 2018).

After each SAT partners could start testing using the MCS. As well as the MCS, GE Renewable Energy also provided each partner with a wide area monitoring system (WAMS) for recording data during the trials. This is the same system used by many operators around the world for WAMS applications, though not all applications were necessary in this project.

CBA assumptions

The technology roll-out capability assumptions for the counterfactual and EFCC scenarios are outlined in Tables 27 and 28.

Technology	Frequency Response	De-load	Response
Offshore Wind	Low	45%	100%
	High	0%	100%
Onshore Wind	Low	45%	100%
	High	0%	100%
Solar	Low	100%	100%
	High	0%	100%
Batteries	Low	100%	100%
	High	0%	100%
DSR	Low	100%	100%
	High	-	-
Interconnectors	Low	-	100%
	High	-	100%

Table 27: Technology roll-out assumptions for the counterfactual case

Technology	Frequency Response	De-load	Response
Offshore Wind	Inertial	0%	1.5%
	Low	45%	10%
	High	0%	10%
Onshore Wind	Inertial	0%	1.5%
	Low	45%	10%
	High	0%	10%
Solar	Low	100%	12%
	High	0%	12%
Batteries	Low	-	-
	High	-	-
DSR	Low	100%	100%
	High	-	-
Interconnectors	Low	-	100%
	High	-	100%

Table 28: Technology roll-out assumptions for the EFCC type 0.5s case

Appendix F

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Making a positive difference for energy consumers

Company Secretary
National Grid Electricity Transmission
National Grid House
Technology Park
Gallows Hill
Warwick
CV34 6DA

Direct Dial: 020 7901 7159
Email: andrew.burgess@ofgem.gov.uk

Date: 19 December 2014

Dear Company Secretary,

Project Direction ref: NGET / Enhanced Frequency Control Capability / 19 December 2014

National Grid Electricity Transmission (NGET) submitted the Project[1], Enhanced Frequency Control Capability (EFCC), on 25 July August 2014 to be considered for funding through the Electricity Network Innovation Competition (NIC). In this year's decision[2], we[3] selected the project for funding.

We have issued this Project Direction to NGET. It contains the terms to be followed by NGET as a condition of EFCC receiving funding through the Electricity NIC. It must comply with these terms, which can be found in the schedule to this direction.

Project Direction

Paragraph 5.66 of the Electricity NIC Governance Document states that a Project Direction will:

- set out the Project-specific conditions that the Network Licensee is committing to in accepting funding;
- require the Network Licensee to undertake the Project in accordance with the commitments it has made in the Full Submission. Where appropriate, the Project Direction may therefore include extracts from the Full Submission or refer to specific sections of the Full Submission;
- set out the Approved Amount for the Project, that will form part of the calculation contained in the Funding Direction issued by the Authority under chapter 7 of the Governance Document;
- set out the Project budget that the Network Licensee must report against and how variances against the Project budget will be reported and approved; and

[1] Unless otherwise specified, defined terms in this Project Direction have the meaning given to them in Appendix 1 of the NIC Governance Document.
[2] Decision on the second year Electricity Network Innovation Competition.
[3] The terms 'the Authority', 'Ofgem', 'we' and 'us' are used interchangeably in this letter. The Authority is the Gas and Electricity Markets Authority. Ofgem is the Office of the Authority.

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- the mechanism for the Network Licensee receiving the Approved Amount is set out in the Funding Direction.

These are described for Enhanced Frequency Control Capability Project in the schedule to this Project Direction.

Decision

Provided NGET complies with the NIC Governance Document and with the schedule to this Project Direction, the Enhanced Frequency Control Capability Project is deemed to be an Eligible NIC Project[4].

This Project Direction constitutes notice pursuant to section 49A (Reasons for decisions) of the Electricity Act 1989.

Yours faithfully,

Andrew Burgess
Associate Partner, Transmission and Distribution Policy
For and on behalf of the Authority

[4] Eligible NIC Project has the meaning given in definitions of the Electricity Transmission licence.

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Schedule to Project Direction

1. TITLE

Project Direction ref: NGET/ Enhanced Frequency Control Capability/ 19 December 2014

2. PREAMBLE

This Project Direction issued by the Gas and Electricity Markets Authority (the "Authority") to National Grid Electricity Transmission plc (the "Funding Licensee") pursuant to the Electricity NIC Governance Document issued pursuant to Part E of Special Condition 3I (Network Innovation Competition) of the Electricity Transmission Licence (the "Licence") sets out the terms to be followed by the Funding Licensee in relation to Enhanced Frequency Control Capability (the "Project") as a condition of it being funded under the NIC and the Funding Return Mechanisms[1].

Unless otherwise specified, defined terms in this Project Direction are defined in Appendix 1 of the Electricity NIC Governance Document.

References to specific sections of the Funding Licensee's Full Submission in this Project Direction are, for ease of reference, made by referring to the section number in the Funding Licensee's Full Submission pro-forma.

3. Condition Precedent

The Funding Licensee will not access any funds from the Project Bank Account until it has signed contracts with the Project Partners named in Table 1.

Table 1 Condition Precedent

Alstom
Centrica
Flexitricity
The University of Manchester
The University of Strathclyde

4. COMPLIANCE

The Funding Licensee must comply with Special Condition 3I of the Licence and with the NIC Governance Document (as may be modified from time to time in accordance with Special Condition 3I and as modified and/or augmented in respect of the Project by this Project Direction) and with this Project Direction.

Any part of the Approved Amounts that the Authority determines not to have been spent in accordance with this Project Direction (or the Electricity NIC Governance Document) is deemed to be Disallowed Expenditure.

Pursuant to Special Condition 3I.8 of the Licence Disallowed Expenditure is revenue received (whether by the Funding Licensee or another Licensee) under the NIC and Funding Return Mechanisms that the Authority determines not to have been spent in accordance with the provisions of the Electricity NIC Governance Document or those of the relevant Project Direction.

Pursuant to paragraph 8.48 of the Electricity NIC Governance Document, Disallowed Expenditure includes any funds that must be returned if the Project is halted without

[1] The Funding Return Mechanism is defined in part C of Special Condition 3I.

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Ofgem's[2] permission, any funds that have not been spent in compliance with the approved Project Budget contained within the Project Direction, and any unspent funds on the completion of the Project.

5. APPROVED AMOUNT FOR THE PROJECT

The Approved Amount is £6,911,880.

6. PROJECT BUDGET

The Project Budget is set out in Annex 1. The Funding Licensee must not spend more than 110% of any category total (e.g. "Labour") in Annex 1 without the Authority's prior written consent (such consent is not to be unreasonably withheld).

The Funding Licensee will report on expenditure against each line under the category total in the Project Budget, and explain any projected variance against each line total in excess of 5% as part of its detailed report which will be provided at least every six months, in accordance with paragraph 8.17 of the Electricity NIC Governance Document. Ofgem will use the reported expenditure and explanation to assess whether the funding has been spent in accordance with the Electricity NIC Governance Document and with this Project Direction.

For the avoidance of doubt this reporting requirement does not change or remove any obligations on the Funding Licensee with respect to reporting that are set out in the Electricity NIC Governance Document.

7. PROJECT IMPLEMENTATION

The Funding Licensee must undertake the Project in accordance with the commitments it has made in the Full Submission approved by the Authority pursuant to the Electricity NIC Governance Document and with the terms of this Project Direction. These include (but are not limited to) the following:

(i) undertake the Project in accordance with the description set out in Section 2 (Project Description);
(ii) provide a Network Licensee Compulsory Contribution of £823,870;
(iii) complete the Project on or before the Project completion date of 31 March 2018; and
(iv) disseminate the learning from the Project at least to the level described in Section 5 (Knowledge Dissemination).

[2] Ofgem is the offices of the Gas and Electricity Markets Authority. The terms 'Ofgem' and 'Authority' are used interchangeably in this Project Direction.

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Appendix F

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8. WORK PACKAGE 2.4 - STORAGE

The Funding Licensee must secure consent from the Authority before accessing the funds, £1,122,820, for work package 2.4. The Funding Licensee must submit an application to the Authority which presents options for work package 2.4. As part of this application, the Funding Licensee must conduct an investigation into existing battery storage facilities and trials in the UK, considering both technical and commercial information, to determine if existing facilities and/or trials can be used for the Project. The Funding Licensee must also present cost benefit analysis of potential learning from this work package against the cost to consumers. The Funding Licensee must present this information in a report to the Authority by 30 June 2015.

Based on the Funding Licensee's application the Authority will determine whether the funds for work package 2.4 will be released. If the Authority determines not to release these funds, the funds will be returned to customers.

9. REPORTING

Ofgem will issue guidance (as amended from time to time) about the structure and content of the reports required by paragraph 8.17 of the Electricity NIC Governance Document. The Funding Licensee must follow this guidance in preparing the reports required by paragraph 8.17 of the Electricity NIC Governance Document.

As required by paragraph 8.22 of the Electricity NIC Governance Document, the Funding Licensee must inform the Authority promptly in writing of any event or circumstance likely to affect its ability to deliver the Project as set out in its Full Submission.

10. COST OVERRUNS

The maximum amount of Discretionary Funding that the Funding Licensee can request as additional funding for cost overruns on the Project is 0%[3].

10. INTELLECTUAL PROPERTY RIGHTS (IPR)

In Section 5 (Knowledge Dissemination) the Funding Licensee has stated that the Project does conform to the default IPR arrangements set out in Section Five of the Electricity NIC Governance Document and must therefore undertake the Project in accordance with the default IPR arrangements.

11. SUCCESSFUL DELIVERY REWARD CRITERIA

The Project will be judged by the Authority for the purposes of the NIC Successful Delivery Reward against the Successful Delivery Reward Criteria set out in Table 3[4] below (that comply with paragraphs 5.26 – 5.29 of the Electricity NIC Governance Document).

Table 3. Successful Delivery Reward Criteria

Successful Delivery Reward criterion	Evidence
Formal contract signed by all Partners In order to achieve the project objectives, it is crucial that all project partners are committed to deliver allocated tasks. At the early stages, establishing this agreement with the project partner is the first measure of success for EFCC.	• Formal contract of EFCC signed by all partners (by the end of March 2015 and prior to accessing the NIC funds) • Flexitricity to have agreements in place with DSR customers (by the end of June 2016 – end of WP2.1.1.6)

[3] This is the amount requested by the Funding Licensee in its Full Submission.
[4] These are the Successful Delivery Reward Criteria set out in the Funding Licensees Full Submission

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Monitoring and Control System (MCS) Developed Successfully One of the key deliverables of the project is to enhance frequency monitoring capability enabling the measurement and comparison of rate of change of frequency at regional level, and distinction between disturbance, from a real frequency event. The development of the MCS is central to this.	Application development: • Event detection algorithm completed (by the end of April 2015 - WP1.1.1) • EFCC resource allocation algorithm completed (by the end of August 2015 – WP1.1.2 • Optimisation algorithm completed (by the end of January 2016 - WP1.1.3) • Testing completed (by the end of April 2016 – WP1.1.4) • Revision completed (by the end of March 2017 – WP1.1.5) Control platform development: • Specification completed (by the end of April 2015 – WP1.2.1) • Development completed (by the end of April 2016 – WP1.2.2) • Controller testing completed (by the end of August 2016 – WP1.2.3) • Revision completed (by the end of July 2017)
Storage Decision Point Full analysis of Storage costs and benefits to be made with final recommendation made to Ofgem on inclusion within EFCC.	• Recommendation made to Ofgem by the end of June 2015 (WP2.4.0)
Response Analysis from Service Providers In this project, we will demonstrate how different technologies will respond to frequency events and their capability to provide response in proportion to rate of change of frequency.	Reports detailing the result of the demonstration of the response from providers: • Demand Side Response WP2.1 (November 2017) • CCGT Power Stations WP2.2 (July 2017) • PV power plant WP2.3 (October 2017) • Storage WP2.4 (October 2017, subject to the Authority's decision on funding Work Package 2.4)) • Windfarm WP2.5 (July 2017)
Successful Validation of Response The project must deliver technology that is effective in reducing the overall response requirement for the grid. To achieve this, it must be demonstrated that response can be optimised to provide the most economic and efficient rapid frequency response. This requires the trails carried out as part of Criteria 9.4, to be validated against the representative models.	• Successful delivery of representative models and validation of trial results using the models (November 2017 – Following all trials and validation activities)
New Enhanced Frequency Response Service Developed Successfully The roll out of EFCC requires a new	• Successful development of new enhanced frequency response service as part of new balancing services

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balancing service to be developed to ensure the savings envisaged are achieved.	(December 2017 – Following WP2 trials) • Report with recommendations regarding implementation of the new service (January 2018 – Delivered through WP6&7)
Successful Knowledge Dissemination Successful dissemination of knowledge generated by EFCC within National Grid, to other transmission owner, DNOs, and industry stakeholders will be carried out to ensure the learnings are communicated at different stages of the project to enable timely roll out of the new balancing service.	• Knowledge sharing e-hub delivered (March 2015) • All non-confidential data and models developed as part of EFCC to be shared on the e-hub (March 2018 – end of project) • Annual knowledge dissemination event (at least one per year) organised (March 2016 – first dissemination event)
Project close and knowledge dissemination The project is planned from January 2015 until March 2018. The project is well organised to satisfy all pre-set objectives and deadlines. Eventually the new control of system frequency and provision of frequency response in proportion to rate of change of frequency is demonstrated and the relevant commercial services are developed. The new approach to control the system frequency will be commercially rolled out at the end of the project.	• The control systems required as part of WP2 (developed by WP1) are demonstrated and validated; • The response capability of the type of services described in WP2 are trialled; • The optimisation based on information gathered in WP2 is carried out; • Validation exercise of the WP1, WP2 and WP3 is carried out as well as further tests in PNDC to mitigate the identified risks; • Knowledge dissemination events as described in the work programme are carried out and results are shared and made available; and • As part of WP6 & WP7, the new balancing service is developed in collaboration with EFCC partners, other service providers, and commercial operation department of National Grid.

The maximum amount of the NIC Successful Delivery Reward (which will not exceed the Licensee Compulsory Contribution) that the Project will be eligible for is £823,870.

12. USE OF LOGO

The Funding Licensee and Project Partners, External Funders and Project Supporters[5] may use the NIC logo for purposes associated with the Project but not use the Ofgem or Ofgem E-Serve logos in any circumstances.

[5] As listed in Box 1.6 in Section 1 of the Full Submission pro-forma.

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13. AMENDMENT OR REVOCATION

As set out in the Electricity NIC Governance Document and in this Project Direction, this Project Direction may be amended or revoked under the following circumstances:

(i) if the Funding Licensee considers that there has been a material change in circumstance that requires a change to the Project Direction, and the Authority agrees (paragraph 8.23 of the Electricity NIC Governance Document); and/or

(ii) if Ofgem agrees to provide Contingency Funding, which requires the re-issue of the Project Direction (paragraph 8.42 of the Electricity NIC Governance Document); and/or

(iii) if the Funding Licensee applies for Discretionary Funding to cover a decrease in Direct Benefits and the Authority decides it would be in the best interest of customers to make changes to the Project Direction before the Discretionary Funding would be awarded (paragraph 8.42 of the Electricity NIC Governance Document).

14. HALTING OF PROJECTS

This Project Direction is subject to the provisions contained in paragraphs 8.30 to 8.34 of the Electricity NIC Governance Document relating to the halting of projects. By extension, this Project Direction is subject to any decision by the Authority to halt the Project to which this Project Direction relates and to any subsequent relevant Funding Direction issued by the Authority pursuant to Special Condition 3I of the Licence.

In the event of the Authority deciding to halt the Project to which this Project Direction relates, the Authority may issue a statement to the Funding Licensee clarifying the effect of that halting decision as regards the status and legal force of the conditions contained in this Direction.

NOW THEREFORE:

In accordance with the powers contained in the Electricity NIC Governance Document issued pursuant to Part E of Special Condition 3I of the Licence the Authority hereby issues this Project Direction to the Funding Licensee in relation to the Project.

This constitutes notice of reasons for the Authority's decision pursuant to section 49A (Reasons for decisions) of the Electricity Act 1989.

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

EFCC NIC Ofgem Approval Letter Dec 2014

ANNEX 1: PROJECT BUDGET

Cost Category	Cost (£k)
Labour	
	2150.00
Equipment	
	1,146.00
Contractors	
	2,486.37
IT	
	90.00
IPR Costs	
	-
Travel & Expenses	
	149.00
Payments to users	
	653.00
Contigency	
	894.32
Decommissioning	
	24.00
Other	
	340.00
Total	**7,932.69**

The Office of Gas and Electricity Markets
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NIC WP2.4 Direction letter Feb 2016

Company Secretary
National Grid Electricity
Transmission
National Grid House
Technology Park
Gallows Hill
Warwick
CV34 6DA

Direct Dial: 020 79017159
Email: andy.burgess@ofgem.gov.uk

Date: 26 January 2016

Dear Company Secretary,

Decision on funding for work package 2.4 of the Enhanced Frequency Control Capability (EFCC) project

I am writing with details of our decision on funding for one of your innovation projects.

On 25 August 2014 you, National Grid Electricity Transmission (NGET), submitted the project 'Enhanced Frequency Control Capability (EFCC)' for funding through the Electricity Network Innovation Competition (NIC). Following a recommendation from our Expert Panel[1], we awarded funding for the project on 19 December 2014, subject to you complying with the Project Direction.[2]

Work Package 2.4 represents a significant proportion of the project costs and is stated in the EFCC full submission as:

"The capabilities of storage resources will be tested and demonstrated with local and external control."

In making the decision to fund this project, we and the Expert Panel raised some concerns about the construction of a new battery storage facility instead of using an existing one and also about the economic benefits of any potential learning. The following condition was therefore set as part of the Project Direction:

"The Funding Licensee must secure consent from the Authority before accessing the funds, £1,122,820, for work package 2.4. The Funding Licensee must submit an application to the Authority which presents options for work package 2.4. As part of this application, the Funding Licensee must conduct an investigation into existing battery storage facilities and trials in the UK, considering both technical and commercial information, to determine if existing facilities and/or trials can be used for the Project. The Funding Licensee must also present cost benefit analysis of potential learning from this work package against the cost to consumers. The Funding Licensee must present this information in a report to the Authority by 30 June 2015.

[1] Electricity Network Innovation Competition: 2014 funding decision
https://www.ofgem.gov.uk/sites/default/files/docs/2014/11/electricitynic_decision_document_2014_0.pdf
[2] Project Direction ref: NGET / Enhanced Frequency Control Capability / 19 December 2014
https://www.ofgem.gov.uk/sites/default/files/docs/2015/01/enic_project_direction_efcc_final_0.pdf

The Office of Gas and Electricity Markets
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NIC WP2.4 Direction letter Feb 2016

Based on the Funding Licensee's application the Authority will determine whether the funds for work package 2.4 will be released. If the Authority determines not to release these funds, the funds will be returned to customers."

The condition, therefore, has two components:

1) Investigation of existing storage facilities; and
2) Cost benefit analysis

Investigation of existing storage facilities

To satisfy the requirements of the condition, on 30 June 2015, you submitted a Battery Storage Investigation Report to us, which we assessed. You emphasised that the innovation comes from pairing storage with solar PV and we were satisfied that there were no other suitable existing storage facilities available for this aspect of the project. In this respect, you had met the first component of the condition: you had demonstrated that existing facilities and/or trials would not be suitable for the project.

Cost benefit analysis

The condition stipulated that you provide a cost benefit analysis of potential learning against the cost to consumers of this work package. In your initial report, you produced a cost analysis only. None of the benefits discussed in the report were monetised.

We asked some supplementary questions on 14 August 2014 and subsequently arranged to have a meeting on 1 October 2015 with your EFCC project team. At the meeting we set out our requirements clearly and were in agreement with the EFCC project team regarding the detail in the cost benefit analysis which we expected. We also agreed that you should include an evidenced-based projection of the number of solar farms that would roll out the hybrid solution which would provide an input to the CBA. We gave you an opportunity to submit an updated report.

You submitted an updated report on 6 November 2015 to us, which we have reviewed. A summary of our assessment is below.

We asked you to show how economically viable it may be for a solar farm to invest in battery storage. We expected to see the potential learning from this NIC project and the related monetised benefits, to a developer, of investing in battery storage. You presented a cost benefit analysis which included only the payment for enhanced frequency response as a benefit.

We also asked you to identify the number and MW capacity of existing solar farms of the minimum practical size or greater for the deployment of this solution. You identified that the minimum practical size would be 4MW based on the trial. You provided a graph showing a combination of both existing farms and those in all stages of development. There is no isolated figure for the number and MW of existing solar farms of the minimum practical size and you did not provide an explanation for this.

The CBA hinges on an assumption that the combination of solar PV and battery storage will represent 30-45% of the market share for enhanced frequency response. Battery roll-out projections are based on meeting this. There is no justification or explanation of this market share figure and, should the outturn market share be different, as you acknowledge in your report, the benefits will also be different. There is therefore considerable uncertainty over a key driver of, and the subsequent potential scale of, the available benefits.

2 of 3

The Office of Gas and Electricity Markets
9 Millbank London SW1P 3GE **Tel** 020 7901 7000 **Fax** 020 7901 7066 **www.ofgem.gov.uk**

NIC WP2.4 Direction letter Feb 2016

The capital cost of a battery is identified as £1,122,820 which you have predicted will come down in future, but you have made no projection of the estimated decrease in cost. We expected to see justification of all figures used.

The benefit is identified as the payment for frequency response, which you have assumed to be [redacted] as this is the approximate current cost of existing frequency response. You note that this could change significantly in the future and you assessed the future costs of frequency response using both linear and quadratic models. The quadratic model suggests that costs will peak at some point and then decrease. Your assessment forecasts costs peaking at just under £1bn/year, but there is no indication of how the costs may decrease or an explanation of how you derived the specific quadratic equation used in the analysis.

We expected a broader investigation of benefits to developers and for these to be either included or disregarded from the CBA with justification. This would inform overall understanding of the economic viability of solar farm developers investing in battery storage.

You included a spreadsheet showing the battery storage NPV calculations with the report, but have not provided an explanation of the spreadsheet. An accompanying discussion was necessary as there are several figures in the spreadsheet which are unexplained.

In summary, the CBA includes a number of assumptions that have not been explained and/or supported by evidence. Although we acknowledge the inevitable uncertainty with any assumptions, we would expect to see thorough analysis and robust justification of the assumptions adopted to make the case. We made this expectation clear at the meeting on 1 October 2015. Absent such justification, we are not satisfied that you have presented a robust cost benefit analysis of potential learning from this work package against the cost to consumers.

Decision

We have reviewed your submissions in accordance with the requirements set out in the Project Direction. We conclude the following:

1) you have made the case for the requirement for a new storage facility for this trial; but
2) you have not made a convincing economic case for Work Package 2.4.

As you have not been able to satisfy both components of the condition, we have decided not to release the funds for work package 2.4. £1,122,820 of the project costs will be returned to customers using the NIC Funding Direction for 2016.

Yours faithfully,

Andy Burgess

Andy Burgess
Associate partner, Energy Systems Integration
For and on behalf of the Authority

Technical lessons learnt

National Grid Electricity System Operator's (NGESO's) System Operability Framework (SOF) has identified potential future operability challenges. The learning outcomes gathered during the project can be applied to several of these areas which are summarised as follows.

Frequency containment
The monitoring and control system (MCS) has been specifically designed to address frequency containment using sophisticated algorithms to initiate response based on rate of exchange of frequency (RoCoF) and system frequency. This potentially addresses the challenge of how to deliver fast, coordinated frequency response while maintaining the stability of the grid.

Visibility of the network
The wide area measurement used by the MCS can be used to provide real-time system inertia estimation. This is beneficial for understanding how the network operates across a wider range of frequency and voltage disturbances and to evaluate risks associated with managing reconnection and precautionary disconnection.

Harmonics and system imbalance
Wide area systems like the MCS could be part of dynamic filtering and power flow management solutions for minimising harmonics and system imbalance. Where flexible dynamic devices are installed on the electricity transmission network, the MCS can be adapted to coordinate such devices and inform modelling across the sub 500ms timeframe.

System modelling
The wide area measurement techniques for detecting RoCoF may be applied directly to the future approaches for relay design and specification. Similarly, understanding of inter-area stability and damping can be used directly to support inertia estimation used for power system analysis. The wide area system can also be used to assist baselining models to simulate risks associated with sub-synchronous torsional interactions (SSTI), and fast fault current injection (FFCI). The European MIGRATE (Massive Integration of Power Electronic Devices) project is developing understanding in this area using knowledge gained from the NIC EFCC and VISOR projects.

Voltage stability
The wide area measurement approach can be used to facilitate calculations for voltage change and to initiate action via the MCS i.e. evaluate and initiate changes in set points to a range of assets to alleviate voltage constraints. This application may be more suited to assisting with slower voltage collapse and requires further development to assess response times.

System restoration
The MCS (via its processing of phasor measurement unit (PMU) data) can provide voltage, frequency, RoCoF, fault level, and phase angle information from across the system. This data can form the basis for developing a pre-emptive islanding strategy as an alternative to system collapse. Pre-emptive islanding could be employed by disconnecting healthy parts of the system to create stable power islands, forming the backbone to reconnecting the system.

Wide area testing techniques
GE Renewable Energy and the universities have designed rigorous methodologies for the testing and validating wide area control schemes, which can be used to inform new specifications and testing processes. These approaches (factory and site acceptance testing, simulations using Hardware-in-the-Loop, etc.) would equally support deployment of advanced active network management (ANM) schemes or other similar systems.

Appendix H

Risks

Table 29 below shows the project risks that are now closed.

Risk ref	Work streams / area	Risk description	Cause	Consequence	Risk closure statement
1	General	Partners leave project before completion.	Partner decides to leave the project. Reason could be commercial, operational, etc.	Work is lost or can't start and the project results are less useful, or the project is delayed.	All partners met their requirements as part of the project.
2	General	Estimated costs are substantially different to actual costs.	Full scope of work is not understood. Cost estimates are not validated. Project is not managed closely.	Overspend requiring Ofgem change request approval.	Project delivered within budget.
3	General	Material costs increase.	The cost of materials rises for unforeseen circumstances.	Potential project funding gap. Alternative funding is needed, or the project scope is reduced.	The project was managed within budget.
4	General	Significant changes to the GB electricity system during the project.	Priorities or strategies for planning and managing the GB system may change.	Solution may no longer be suitable. Assumptions may no longer be accurate or appropriate.	The revised system studies show there is benefit in the approach outlined by the project.
5	General	Critical staff leave National Grid ESO or our project partners during project lifecycle.	Usual and unavoidable staff turnover results in key staff leaving National Grid ESO or our project partners.	The project is delayed. The project team doesn't have the expertise to deliver the project.	Employee retention policy developed and used during the project, minimising the impact of people leaving the project.
6	General	The monitoring and control system and/or equipment installed at response sites is not good enough.	Least cost option given precedence over quality and reliability; suppliers' quality control is not enough.	The solution offered is not reliable and commercial opportunities will be reduced. Delays and replacements cause extra costs.	This risk is deferred to the proposed NIA (MCS demonstration). However, the MCS has already been robustly tested by commercial and academic partners.
7	General	Technology cannot be easily upgraded.	Monitoring and control technology and/or response equipment is designed without considering developments.	Technology is less useful in the future as the electricity system continues to develop. The upgrades needed are costly or impossible.	Future requirements considered and built into specification. Flexibility has been built in. Scheme updates can be managed through library updates.

8	WP6 Commercial	Costs of solution over lifetime are high.	Full cost of solution is not considered and/or understood.	The solution's usefulness and commercial opportunities are restricted.	Full implementation costs are substantial, however this is mitigated by the proposed phased implementation of the MCS and alternative interface solutions identified during the project.
9	General	Academic service providers can't recruit appropriate staff to work on the project.	Lack of suitable candidates or interest in the project.	Trials are limited or can't take place. The suitability and performance of the technology is not established.	Delays in recruiting academic researchers (due to long contractual negotiations) resulted in amendments to the project deliverables. Strategies were implemented to minimise impact on project timeline, such as additional project resources for academic work packs.
10	General	Component failure during project.	Equipment will be run in new ways that may cause problems or failures.	The equipment may need to be repaired or replaced. The tests may be delayed.	There was no major component failure during the trials. Partners provided extensive expertise and support.
11	General	Strategic spares policy.	Spares policy for new technology may not be suitable when all risks are considered.	If suitable spares are not identified and available, the risks of losing the PMU/ controller in the network may make the project less effective.	Assumptions were made about redundancy for the MCS and PMUs. Also, EFCC requirements were fed into wider ESO business strategy for wide area monitoring and control scheme.
12	General	Maintenance requirements.	Manufacturer recommends intensive and regular maintenance that does not fit with project owner's expectations.	Regular intensive maintenance requires additional field staff. This could affect the network operation, reducing power transfer levels and constraint costs.	No maintenance was required during the project. Maintenance of the MCS is expected to be infrequent and non-labour intensive because of the system design and the associated lifespan of the equipment.

13	WP7 - Comms	Loss of telecom-munications.	Technical fault leads to loss of telecommunica-tions between systems.	Reduced availability and performance.	This risk is deferred to the proposed NIA (MCS demonstration) and subject to further impact assessment before BAU implementation.
14	General	Inefficient operation of MCS.	MCS incorrectly configured, resulting in spurious tripping or too many control initiation commands.	Over-response from resources reducing stability; too many set-point changes in generators reducing asset lifetime.	This risk is deferred to the proposed NIA (MCS demonstration). However, the MCS has already been robustly tested by both academic partners.
15	General	High operation and maintenance costs.	Cost for inspection, maintenance, repairs, spares, etc. are higher than expected.	Excessive OPEX costs compared to current alternatives.	Estimates have been included within the cost benefit analysis. These figures will be revised as we move into BAU.
16	General	Delays in installing key control scheme components.	Supplier of TO/TSO delays base installation. Delays in implementing control scheme platforms and comms routes to PMUs/controllers/ controllable resources. Co-ordination of National Grid and supplier staff availability.	Delays in key control scheme component will push back the trial, leaving less time for reports, tuning and dissemination.	Supplier chosen has experience of deploying wide area monitoring systems (including controllers) in utility environment. PMUs were installed per plan.
17	WP7	Communication between devices underperforms.	Communication infrastructure is not fit for purpose.	The existing communication infrastructure may inhibit the speed of control response, reducing scheme effectiveness.	This risk is deferred to the proposed NIA (MCS demonstration) and subject to further impact assessment before BAU implementation.
18	General	Outage required for commissioning.	Inability to obtain the routages needed for commissioning.	Possible delays to commissioning programme or cost of outage.	Outages acquired as necessary and PMUs installed.
19	General	Commissioning procedures encounter problems.	Commissioning procedures are unclear or untested, being difficult to complete in practice.	Delays in commissioning the project.	PhasorControllers will be installed by experienced contractors for the NIC and NIA MCS demo. They are fully aware of commissioning requirements.

20	General	Capital costs.	Costs higher than anticipated.	Project budget exceeded.	Project budget was not exceeded through careful financial management.
21	Health, Safety and Environmental	Use of new equipment causes a safety incident.	Lack of experience and knowledge about new pieces of equipment.	Health and safety risks caused by lack of experience. Inefficient working could result. Note that controller is low voltage equipment, and actions are taken through existing standard protection and control equipment.	Phasor controllers will be installed by experienced contractors and tested in an open loop environment, minimising the health and safety risk.
22	WP1 - Control System	Technology partner does not deliver suitable product on time.	Problems with design and build.	Project is delayed.	Demonstrations of hardware functionality successfully demonstrated during training, demonstration and SAT. Firmware and bug fixes carried out during the project.
23	WP1 - Control System	Technical specification is not clear enough to deliver the technology or contain errors.	Requirements not fully understood. Insufficient quality control processes.	The technology developed may not match requirements or be suitable.	GE Renewable Energy developed the MCS and met the agreed technical specification, including changes to MCS approach.
24	WP1 - Control System	Flexible embedded real-time controller not commercially available.	A controller with the flexibility to employ the required algorithm is not currently available and will require significant development. Resources must be in place for a timely start to the platform development.	Delays in sourcing suitable resources may extend the development period and delay deployment and trials.	Hardware functionality successfully demonstrated during training, demonstration and SAT. Firmware and bug fixes carried out during the project.

25	WP1 - Control System	Event detection and response algorithms not available on embedded real-time controller.	The controller will use custom functions that are not currently available on the embedded control platform to determine the appropriate reaction. These functions must be developed and tested before deployment. New control approaches need to be developed.	The development period must be extended, which delays all consecutive elements of the project.	Event detection and response algorithms have been successfully tested and validated by academic partners.
26	WP1 - Control System	Resource interoperability.	Using distributed resources for frequency response is untested in the UK and the availability of resources when called upon is critical. Information must be exchanged between the controller and the individual resources so that resources can be called upon as needed.	Lack of comms path or interoperability issues between the controller and the resources may delay a response and reduce the central control scheme's ability to halt frequency excursions.	This risk shall be further tested during the proposed NIA (MCS demonstration). However, the MCS has already been robustly tested by both commercial and academic partners.
27	WP1 - Control System	Resource flexibility.	Resources do not offer enough flexibility for control under proposed control scheme. They either offer a response that is difficult to quantify or one that is difficult to tune.	The control scheme may need redesigning, delaying deployment.	Resource flexibility built into the control scheme and validated by the academic partners.
28	WP1 - Control System	Control scheme trial outcome.	As the project is an innovative project, the selected control scheme's trials may yield negative results, or introduce additional problems.	The selected control scheme will be unable to effectively deploy resources to arrest a frequency excursion.	Demonstrations of hardware functionality successfully demonstrated during training, demonstration and SAT. Interfaces between control scheme and commercial partners have been successfully tested.

29	WP1 - Control System	Controller scalability for roll-out.	The controller will be developed for trial locations using a limited number of sites and corresponding PMU measurements. The control platform's performance may be reduced because of more measurement and resource data with larger-scale roll-out. Another risk is exceeding the computational capacity of the controller with complex algorithms and increased inputs, e.g. more resources to optimise.	Timely roll-out of the scheme could be put at risk, delaying full effectiveness and action on learnings from the project.The risk for this stage of the project is minimal.	This risk shall be further tested during the proposed NIA (MCS demonstration). However, the MCS has already been robustly tested by both commercial and academic partners.
30	WP1 - Control System	Additional testing and tuning.	The controller may require additional tests and fine tuning based on real system measurements from the UK network to ensure robust operation. Data will need to be gathered over enough time to determine the control scheme performance.	The selected control scheme will be unable to effectively deploy resources to arrest a frequency excursion.	The MCS was robustly tested by academic and commercial partners. Further testing will be conducted as part of the proposed NIA MCS demonstration.
31	WP1 - Control System	Data quality.	Inadequate data quality from PMUs due to problems with communications infrastructure, incompatible PMUs, or from existing PMUs where experience has shown poor quality data.	Controller application value and performance reduced.	Data quality is an integral part of concepts/exception handling. UoS validation focused on these issues with satisfactory results during testing. UoS test report confirmed robustness/ operational readiness of SFC scheme/ functionality.

32	WP1 - Control System	RoCoF trip risk.	Controllable resources that arrest frequency excursion may be conflicted by own loss of mains RoCoF settings and trip. Also, risk of fast response rolling off at df/dt=0 when it should be sustained.	Loss of effectiveness of resources - unavailable for frequency support or prematurely returned to normal service.	For trial purposes, RoCoF was low enough to avoid conflicts in terms of loss of mains (LoM) detection. The issue will require further consideration for future roll-out.
33	WP2.1 - DSR	Flexitricity can't provide participants for planned trials.	Timing, risk and commercial terms make it difficult to recruit DSR participants.	Trials are limited or unable to take place. The technology's suitability and performance is not established.	Flexitricity successfully recruited six participants across three different types of trials.
34	WP2.1 - DSR	DSR recruitment: industrial and commercial electricity customers unwilling to participate.	I&C energy managers' workloads, comprehension of the proposition, duration of trials, uncertainty of long-term commercial service, opportunity cost.	Not proved that DSR can deliver EFCC.	Flexitricity successfully recruited six participants across three different types of trials.
35	WP2.1 - DSR	DSR trials prove unfeasible.	Complex technical interaction with existing commercial site processes.	Ability of DSR to deliver EFCC not proven.	Trials were successfully conducted across all three technical approaches.
36	WP2.1 - DSR	Total delay between detection and action too long for distributed resources including DSR.	Long signalling chain including communicating with remote sites.	Cannot dispatch certain resources fast enough.	All detection takes place locally and signal chains have been kept to a minimum. Communications requirements for a wide area roll-out would need more investigation.
37	WP2.1 - DSR	Cost of DSR too high for large-scale roll-out.	Controls modifications (especially RoCoF and simulated inertia), spark spread (especially real inertia).	Project does not result in economic source of EFCC from DSR.	Trial results have indicated that alternative approaches to implementing a DSR service could be used to minimise implementation costs.
38	WP2.1 - DSR	DSR deployment lead time too long.	Normal delays in dealing with industrial and commercial energy users.	Unable to operate long enough trial; some customers are ready for trial too late.	Flexitricity completed trials in extended project timeline.

39	WP2.2 - Large-Scale Generation	CCGT operators struggle to get relevant technical input from original equipment manufacturer (OEM).	Lack of communication or timely response from OEM.	The project is delayed.	Risk did not materialise within project timeline.
40	WP2.3 - PV Power Plant	Bad weather (low irradiation).	Poor weather conditions will mean that trials cannot take place.	Insufficient test conditions will lead to delays in testing.	BELECTRIC completed trials in extended project timeline, which accounted for all weather conditions.
41	WP2.4 - Storage	Local problems delay installation and commissioning.	Issues around grid connection and accessibility cause delays.	The project is delayed.	Closed as work pack 2.4 is descoped. New risk register created as part of NIA project.
42	WP3 - Optimisation	Detailed models of the various technology types are not made available to academic partners for system studies.	Poor communication and project management. Possible restrictions on data.	Without detailed technology models, any optimised control scheme will be based on generic assumptions about technology capabilities which may not be accurate. This means that true and simulated performances will not align.	Detailed models of the various technology types were developed by academic partners, with input from commercial partners, for their system studies resulting in more accurate modelling.
43	WP4 - Validation	Unable to model the UK network with sufficient detail using the RTDS's facilities to thoroughly validate proposed control solutions.	Lack of required data. Lack of expertise on project.	Issues not flagged during the validation phase may severely affect the wide-scale roll-out.	A sufficiently representative model of the GB electricity transmission system was developed.
44	WP5 - Dis-semination	Knowledge gained from the project is not shared properly with industry and other interested parties.	Lack of resources dedicated to dissemination. Failure to deliver events, website, etc.	A major benefit of, and reason for, the project is lost. Performance of solution and lessons learned are not shared.	Several dissemination events and activities held; the project close report was written and shared on the website.
45	WP6 - Commercial	Market for EFCC not taken up by possible resource providers.	Knowledge not disseminated, meaning providers unable to prepare. Commercial arrangements not attractive.	The successful roll-out of the solution will be delayed.	The roll-out strategy can determine market access arrangements should it be implemented within BAU activities.

46	WP1 - Control System	Demonstration partner fails to install and configure demonstration set-up on time for SAT.	Challenges with installation and configuration or lack of understanding/ training.	Demonstration is delayed, which is likely to affect other activities.	GE Renewable Energy provided pre-installation PMU/MCS training. GE Renewable Energy also provided onsite support during installations, including SAT. Deployments at all partner sites were completed successfully.
47	WP1 - Control System	PMU/MCS hardware delivery.	Late delivery of PMUs and/or MCS controllers.	Demonstration is delayed, which is likely to affect other activities.	Equipment delivered to allow all trials to be completed on time.
48	WP1 - Control System	The number of interface protocols affects the development and testing effort.	Project partners decide on multiple interfaces and/or different messaging protocols.	Extra design, development and testing effort needed, which would affect project delivery timelines.	Interfaces delivered and tested with partners.
49	WP2.4 - Storage	Ofgem needing to accept storage in "Smarter Frequency Control".	Insufficient argumentation in front of Ofgem.	Storage combined with PV not part of "Smart Frequency Control".	Closed as work pack 2.4 was descoped.
50	WP2.5 - Wind	EFCC project needs to agree with all Joint Venture partners the use of Lincs, Lynn or Inner Dowsing.	Delay in agreeing use of wind farm.	Delays to project.	Wind package was rescoped to include trials on a commercial wind farm; additional simulation testing and trials at a 7MW wind turbine testbed facility.
51	WP2.5 - Wind	EFCC project needs to agree with Ørsted (formerly DONG), Siemens Gamesa and associated Joint Venture partners for the use of wind farm (test to be conducted on 6 MW turbines without de-loading).	Delay in agreeing use of wind farm.	Delays to work package and overall project outcomes.	Wind package was rescoped to include trials on a commercial wind farm; additional simulation testing and trials at a 7MW wind turbine testbed facility.

52	WP1 - Control System	Number of PhasorController applications.	Concept design frequency control has identified potential for the following controller applications: - local PhasorController for system aggregation, fault detection, event detection and resource allocation. - regional controller for regional aggregation and fault detection. - central PhasorController for management and distribution of configuration data (settings, thresholds, parameters).	Depending on the demonstration schemes envisioned, more hardware may be needed. Extra effort may be needed to develop, configure and test extra controller units	GE Renewable Energy worked with project partners to establish suitable demonstration setups and the associated PhasorController requirements.
53	WP1 - Control System	4-20mA interface.	4-20mA currently not part of TPSA product roadmap due to other priorities.	Full 4-20mA interface not ready for demonstration testing.	Additional equipment bought and trials completed at Centrica/EPH.
54	WP1 - Control System	Digital interface not ready for testing.	Capabilities of digital interface limited. Alternative hardware solution needed for more than six digitals. Product enhancement needed within TPSA product roadmap.	Full digital interface not ready for demonstration testing if more than six digitals needed.	Additional equipment purchased and trials completed at Centrica/EPH. Digital interface successfully tested.
55	WP2.5 - Wind	Revised timeline for wind work package does not coordinate with the other work packs.	Delays caused by the length of time to sign new partner contracts and unforeseen model data validation issues.	Wind test findings not being available in time for meaningful inclusion in the project conclusions and recommendations.	Scope for wind Phase 2 was agreed and completed within project extended timelines. This included collaboration with University of Strathclyde.

56	WP3 - Optimisation	Revised timeline for University of Manchester affects work deliverables of the project.	University of Manchester deliverables slipping because of delays in project recruitment and acquiring the appropriate tools for the systems studies.	Timeline for work deliverables compromised.	The scope of WP3 was altered during the project due to modelling constraints. However, this allowed the project to investigate in greater depth an alternative method of implementation for a wide area monitoring and control scheme. Work was completed within project extension timelines.
57	General	General back loading of deliverables in the project.	Slippage against baseline for deliverables.	Compromising scope and quality of deliverables.	All project deliverables completed in extended project timeline.
58	General	Handoffs between partners are delayed.	Handoffs are not clear in the plan or not proactively managed to ensure the planned timeline is kept.	Delays compromising other work deliverables.	Handoffs and dependencies between partners were managed to enable completion of project deliverables.
59	WP4 - Validation	System testing is delayed.	Additional trial equipment requirements identified which are not immediately available. Identifying an issue in MCS and communication with GE Renewable Energy to receive a new AFB framework about unexpected behaviour might also cause a delay in HiL-testing.	Delay in testing phase, delaying the general project timeline.	Close coordination between GE Renewable Energy and the universities ensured issues were resolved as quickly as possible and the test schedule was completed within project extension timelines.
60	WP2 - All	Test programme and schedule not clearly defined.	Test programme format not clearly defined, affecting scheduling of commercial trials.	Delays in test plan starting and quality of test outputs.	Testing schedule was drawn up with templates supplied. Technical issues with testing and challenges to test schedules were resolved in Steering Group meetings.

61	WP2.2 - Large-Scale Generation	Trial timeline delayed due to potentially volatile market prices.	Recent high market prices create reluctance to carry out non-essential work on plant.	Centrica/EPH delays testing programme.	National Grid ESO issued a limited operational notification meaning that trials could be done within project timeline and minimising risk to the plant's commercial operation. This incorporated adjustment to CCGT logic made by Centrica/EPH.
62	WP7 - Comms	Delay in delivering the work package.	Understanding the nature of the WP deliverables and unable to access specialist resourcing skills.	Work package is not delivered on time, undermining success of project.	WP7 delivered within project timeline.
63	WP6 - Commercial	Delay in delivering the commercial work package.	Understanding the nature of the WP deliverables and unable to access specialist resourcing skills.	Work package is not delivered on time, undermining success of project.	NGESO resources with external commercial expertise recruited onto the project. CBA work outsourced to Baringa and results disseminated. Work package rescoped to align with FRSO flexibility work stream.
64	WP2.2 - Large-Scale Generation	Centrica/EPH unable to participate in project and deliver WP2.2.	Centrica/EPH selling CCGT which is earmarked for trials.	Centrica/EPH do not complete trials putting WP2.2 at risk of non-delivery.	Centrica/EPH reached agreement for continued use of the plant during project timelines.
65	WP2.6	A meaningful NGESO demonstration (simulation and/or network) is not delivered.	Lack of clarity in original submission and difficulty in differentiating NGESO demonstration from other partners' demonstrations.	Lack of evidence of how the system would operate in a real operational environment.	This risk is deferred to the proposed NIA (MCS demonstration).
66	WP2.3 - PV Power Plant	Insufficient time left to complete trials.	Equipment failure and delays to the installation of other components (batteries).	Insufficient data to draw any meaningful conclusions to feed into commercial work package. Delays in project milestones (SDRC).	BELECTRIC completed trials in extended project timeline.
67	WP2.1 - DSR	Delays to dynamic RoCoF trials.	Insufficient operational hours at dynamic RoCoF sites.	Insufficient data to draw any meaningful conclusion to feed into commercial work package. Delays in project milestones (SDRC).	Dynamic RoCoF trials completed in extended project timeline.

68	WP4 - Validation	Delay in finishing all the test activities and requirement for extra staff and PNDC facility time.	Issues were identified during tests and need extra time for GE Renewable Energy to fix and further tests are required to verify the new versions of the system.	Delay in overall project schedule.	Testing completed within timescales.
69	WP3	UoM workload is too broad to demonstrate applicable system outcomes from EFCC.	Scope of WP3 was unclear.	Not enough information on effects of EFCC in the future in the project closure report.	National Grid ESO worked with UoM to redefine work package scope making sure project outputs are relevant.
70	WP7 - Comms	Existing telecommunications network and PMUs can't support the developed MCS functionality for BAU roll-out.	Incompatible communications protocols used, plus differing ETO and SO priorities for the same fault recorder equipment with PMU functionality enabled.	Fault recorders and dynamic monitoring equipment process frequency data for system monitoring purposes. The project is unable to achieve the targeted speed of response times.	This risk is deferred to the proposed NIA (MCS demonstration.)
71	WP2.6 - NGESO Demonstra-tion	The data input into the MCS for the NGESO demonstration is likely to be complicated, manual and time intensive.	The MCS developed is a prototype and therefore not as user friendly as it could be!	The NGESO demonstration could be difficult to implement and very time consuming, leading to potential delays.	This risk is deferred to the proposed NIA (MCS demonstration). NGESO demonstration will use the agreed approach in that only one or two settings will be changed.
72	WP4 - Validation	Delay in completing stage 2 physical testing due to fault in MG set. Replacement part has a 2-3 week lead time.	The MG set tachometer has developed a fault that prevents the MG set from running.	Delays in overall test completion schedule.	MG parts sourced and trials completed in project extension timelines.
73	WP2.3 - Solar	Lack of contract with new solar farm owners means that the solar trials do not take place.	BELECTRIC have sold the solar farm to new owners who are not contracted with NGESO to carry out the trials.	Project doesn't meet one of original aims.	Contract negotiated with solar farm owners for access to complete trials.
74	General	Ofgem refuses project extension request.	Project extension request is expansion of scope and/or budget that is rejected by Ofgem.	Project has to complete on time, within original scope and to budget.	Ofgem approved project timeline extension request. No change to original project scope or financial budget.

75	WP1 - Control System	Reason RPV311 (PMU) has shown unexpected behaviour in terms of data jumps.	Reason RPV311 algorithm/time synchronisation issues.	Control scheme may act on data jumps/ spikes which are not related to an event. The RPV data becomes somewhat unreliable for control purposes.	A workaround for the data jumps experienced by the RPV311 was implemented meaning that trials were able to conclude. However, further mitigation strategies (i.e. using P-class devices) would be needed for a full-scale business as usual roll-out.
76	WP2.2 - Large-Scale Generation	Centrica/EPH fail to agree on continuing the project.	Likely to be down to split of monies still outstanding.	Formal conclusion of project would not be reached. The project and various companies would suffer reputational damage.	Centrica/EPH reached agreement for continued use of the plant during project timelines.
77	WP5 - Dissemination	Dissemination materials are not ready in time or good enough.	Partners and NGESO work packs develop materials behind schedule without time for a thorough review cycle.	Potential contradictory messaging between presenters and/or incomplete messaging on the day.	Presentations for dissemination events were created in time, reviewed, reported the latest position of the project, and were published on the project website.
78	WP5 - Dissemination	Lack of market engagement.	Not clarified the next steps of dissemination.	Reputational and potentially undermine commercial implementation.	Several dissemination events and activities held that were well attended and provided good external engagement.
79	WP2.6 NGESO Demo	NGESO cyber security won't allow a demonstration.	GE Renewable Energy boxes are unsecure.	No live demo.	Cyber security test occurred, medium to low risks identified that should not pose a limitation on the demonstration.
80	WP6 - Commercial	Delays to the CBA being created.	Delay in Baringa starting and/or data inputs required being delayed or incomplete and/or consultant fee delayed sign off.	CBA not being complete or ready for dissemination event and/or ready for frequency market roll-out.	CBA completed within project timeline and results shared with the industry (Q3 2018).
81	WP2.6 NGESO Demo	NIA additional funding not approved.	Business not comfortable with approach/benefit.	Very limited opportunity for trials and therefore scope of meaningful results.	Funding approved subject to conditions that have been addressed.
82	WP4 - Validation	Lack of visibility of academic test results.	Delays to academic reports.	Does not validate monitoring and control suite.	Trials have been completed and reports are being finalised.

83	WP4 - Validation	Delays to UoS's academic testing schedule.	Continuing monitoring and control boxes not operating as expected. Additional upgrades to functionality required.	UoS has to perform retesting/reworking.	Close coordination between GE Renewable Energy and the universities meant that issues were resolved quickly to maintain the testing schedule. Contingency funding was made available to ensure access to resources at PNDC.

Table 29: Project risks

Glossary of terms

Term	
Analogue control signals	A voltage or current signal used for control functions where the desired behaviour is proportional to the value of voltage/current, such as a 4-20mA signal used by legacy control equipment.
Automatic Voltage Regulator (AVR)	This device is used to automatically maintain a generator's electrical output terminal voltage within pre-set parameters.
Binary trip	An on/off control signal, such as tripping of a circuit breaker or load.
Busbar or bus	Copper, brass or aluminium bars used to distribute electricity as connection points for electricity lines within substations.
Combined Cycle Gas Turbine (CCGT)	A combined-cycle power plant uses both a gas and a steam turbine together to produce up to 50% more electricity from the same fuel than a traditional simple-cycle plant. The waste heat from the gas turbine is routed to the nearby steam turbine, which generates extra power.
Central Application Processor	This is where main algorithms and data processing are performed in a centralised control scheme.
Central Supervisor	This is the interface to the National Grid ESO control room. It coordinates the monitoring and control system and manages individual local controllers and their corresponding energy technologies.
CHP	A combined heat and power plant (CHP) produces heat and electricity.
Closed Loop	An automatic control system in which an operation, process, or mechanism is regulated by feedback.
Control Initiation Block	A function block in the control scheme that initiates the control signals to a resource.
CPU	Central processing unit is an electronic circuit that carries out the instructions of a specific computer program.
DIgSILENT PowerFactory	Power systems analysis software used to analyse the transmission and distribution networks.
DPL	DIgSILENT programming language.
DSL	DigSILENT simulation language.
DCS	Distributed control system.
Eigenvalue Analysis	This is used to investigate the oscillation behaviour of a linearised power system model.
Electricity Management System	Software applications used by National Grid ESO to manage and operate the electricity network.
Energy imbalance	This is the difference between generation and demand on the electricity system.
Ethernet controller	Integrated circuit chip that controls ethernet communications.

Event detector	A function block in the control scheme that performs fast frequency-event detection using wide area or local frequency measurements.
Factory Acceptance Test	A process that verifies that the equipment is built and operating in accordance with design specifications.
Flash Memory	An electronic non-volatile computer storage medium that can be electrically erased and re-programmed.
Flexible Controller Platform	The GE Renewable Energy PhasorController is a real-time control platform with an IEC 61131 PLC (programmable logic controller) environment for designing complex control schemes and communication protocols for compatibility with multiple systems.
FPGA	Field-programmable gate array (FPGA) is an integrated circuit designed to be configured by a customer or a designer after manufacturing.
Function Block Diagrams (FBDs)	A graphical method of programming in an IEC 61131 PLC (programmable logic controller) environment.
Future Energy Scenarios	Future Energy Scenarios (FES) provide transparent, holistic paths through future, uncertain energy landscapes. The FES publication is part of a suite of documents NGESO produces as part of the FES process.
GPS	Global positioning system. A satellite-based radionavigation system for global navigation.
Graceful degradation	The ability of a control scheme to continue operating with limited functionality when there is degradation in data.
Hardware-in-the-Loop	A technique that is used when developing and testing complex, real time, imbedded systems.
IDE	Integrated development environment is an application used for software development that allows a user to modify and debug programming code.
IEC 6150 GOOSE	International Electrotechnical Commission (IEC) 6150 is an international standard defining communication protocols for intelligent electronic devices at electrical substations using the Generic Object Orientated Substation Event (GOOSE) protocols.
IEC 61131-3	Part 3 of International Electrotechnical Commission (IEC) 61131-3 deals with basic software architecture and languages of the control programme within a programmable logic controller (PLC).
IEC 61850	International standard defining communication protocols for IEDs.
IEDs	Intelligence Electronic Device (IED) is a term used in the electrical power industry to describe micro-processor based controllers of power system equipment such as circuit breakers, transformers and capacitor banks.
IED Scout	A software tool for interfacing with IEC 61850 devices.
Inter-area effects	During a frequency and/or voltage disturbance, the imbalances in active and reactive power are not evenly distributed across a power system. These differences instead vary across the network depending on the location of the disturbance within the network, capability of nearby generation to respond and the characteristics of the intervening network across the period the disturbance is observed and then responded to. Inter-area modes are an established power system phenomenon where, because of the disturbance the generation at different locations within the network respond to the effect of each other's action upon the network, so that their behaviour oscillates with one another. This oscillation can be an oscillation in the power transferred across the network, the frequency seen at different locations across the network, and in the voltages supporting the power transfer. If

	there's not enough damping, the scale of power oscillation may de-stabilise the power system or drive high power transfers, which could cause the network to separate or a black-out. Within any frequency event, the inter-area oscillation of frequency results in different frequencies across the first 0.5s being used to trigger and dispatch fast frequency resources under EFCC.
Kdf	Term used to represent a gas turbine frequency response within a turbine control scheme.
Line trip	Disconnection of an electricity power line when a fault is detected.
Loss of load	A loss in demand.
Local Controller	An element of the monitoring and control system at various energy technology sites. It instructs energy technologies to respond to resolve the detected frequency event.
LFDD	Low frequency demand disconnection is an automatic low frequency control scheme. The scheme disconnects demand in stages during a severe under-frequency event to maintain the integrity of the electricity network as much as possible.
M-Class (Measurement)	A performance class for Phasor Measurement Unit (PMU) used in monitoring schemes, with slower response time but greater precision than P-class.
Metadata	Metadata is a set of data that describes and gives information about other data.
MMS	Manufacturing Message Specification (MMS) is an international standard messaging system for exchanging real time process data and supervisory control information between network devices or computer applications.
MODBUS and MODBUS TCP/IP	Is an open source communications protocol used for transmitting information over serial lines between electronic devices. MODBUS TCP/IP (Transmission Control Protocol/Internet Protocol) uses MODBUS messaging over the internet.
National Electricity Transmission System (NETS)	The high voltage electricity system in Great Britain including offshore transmission lines.
Open loop	In an open loop control system the output has no influence or effect on the control action of the input signal.
PADCON	A company that specialises in monitoring systems, plant communications and controls for PV power plants.
P-Class (protection)	A performance class of Phasor Measurement Unit (PMU) used for protection schemes where speed of measurement is critical. It responds faster with lower precision than M-class.
Phasor Measurement Units (PMUs)	Is a device used to estimate the magnitude and phase angle of an electrical phasor quality such as voltage or current, using a common time source for synchronisation.
PhasorController (PhC), PhC control platform	A fast real-time control platform with an IEC 61131 PLC environment for creating customisable control schemes, combined with a number of protocols to allow interfacing with multiple systems in an electric grid.
PLC	General term for a Programmable Logic Controller (PLC), a controller used in many industries for automating processes. Allows users to build customised control logic for their particular processes, which has been standardised in IEC 61131.
Power-Hardware-in-the-lLoop (P-HiL)	P-HiL is a testing methodology where physical power equipment (e.g. electrical devices such as generators) are connected to a network simulation model in a Real Time Digital Simulator.

PuTTY	An open-source software tool that facilitates direct access to a server. It supports several network protocols including SCP and SSH.
Quad core CPU	A quad core processor is a chip with four independent units called cores that read and execute Central Processing Unit (CPU) instructions.
Rate of Change of Frequency (RoCoF).	The rate at which frequency changes. This measurement of change is also used on small generation protection relays that disconnect generation at excessive levels of RoCoF. RoCoF tends to be measured across defined periods (500ms being typical). Against linearised power system equations, RoCoF, when appropriately calculated, is proportional to the power imbalance during the event.
Regional Aggregator	An element within the monitoring and control system that processes and gathers measurements from phasor measurement units across the network and passes aggregated signals to the local controller.
Resource allocation	A functional block in the control scheme responsible for deciding where to deploy response and manage that deployment for a particular resource when there is a frequency event.
RSCAD	Proprietary power system simulation software designed specifically for interfacing with Real-Time Data Simulator (RTDS) hardware.
Site acceptance test (SAT)	A test performed to validate equipment operation after installation and commissioning on a customer site.
SCADA	Supervisory control and data acquisition is a system that allows control of plant or machinery locally or at remote locations via a user interface.
Secure Shell (SSH)	A network protocol that gives users, particularly system administrators, a secure way to access a computer over an unsecured network.
Secure Sockets Layer (SSL)	The standard security technology used to establish an encryted link between web servers and browers to ensure data remains private.
SFTP	SSH file transfer protocol is a network protocol that provides computer file access, transfer and management.
Spinning Inertia	The mass of generators connected to the electricity transmission system.
Static RoCoF	Demand side resources triggered on the basis of frequency or RoCoF to disconnect or ramp in response to a signal.
System aggregation	A functional block in the control scheme that performs an averaging function on frequency signals calculated at a regional level to provide a system equivalent frequency measurement.
Synchronous embedded plant	Generation (for example biomass, small CCGT or Open Cycle Gas turbines) and/or devices such as motor load that are synchronously coupled to a power system, and embedded within a distribution network operator's system, rather than directly connected to the GB transmission system.
Synchrophasor measurements	The measurements provided by a Phasor Measurement Unit (PMU), defined by the IEEE C37.118 standard.
Transmission Control Protocol (TCP) and TCP/IP	A network communication protocol to send data over the internet. TCP/IP (internet protocol) creates a connection (handshake) between the sender and receiver before data is transmitted.
User Defined Function Blocks (UDFBs)	The term used for a functional block created by a user in a PLC environment, typically encapsulating a dedicated task.

User Datagram Protocol (UDP) and TCP/IP	A communication protocol that establishes low latency and loss-tolerating connections between applications on the web. The protocol assumes error-checking and correction is not required to minimise processing time.
RAM	Random access memory (RAM) is a form of computer data storage for data and machine codes currently being used.
Wide area monitoring	The process by which PMU measurements are obtained and aggregated within a software platform to provide the operator with information about system and resource performance across an event.
Wide area control	A generic term describing systems such as the MCS that augment the software platform of a WAM scheme to also generate reliable and accurate control information within time limits and the constraints of control hardware.
WinSCP	Open source application for file transfer to and from servers.
Zonal Aggregators	Term previously used to describe Regional Aggregators.