Power engineering and trials

Report on the viability of restoration from DERs (Redacted version)
31 July 2019

In partnership with:

tnei

SP ENERGY NETWORKS

nationalgridESO

Contents

Abstract

The Distributed ReStart project (formerly known as Black Start from DER) is a partnership between National Grid electricity system operator (ESO), SP Energy Networks (SPEN) and TNEI (a specialist energy consultancy) that has been awarded £10.3 million of Network Innovation Competition (NIC) funding.

The project is exploring how distributed energy resources (DER) can be used to restore power in the highly unlikely event of a total or partial shutdown of the National Electricity Transmission System. Past and current approaches rely on large power stations but as the UK moves to cleaner, greener and more decentralised energy, new options must be developed. The enormous growth in DER presents an opportunity to develop a radically different approach to system restoration. Greater diversity in Black Start provision will improve resilience and increase competition leading to reductions in both cost and carbon emissions. However, there are significant technical, organisational and commercial challenges to address.

The project will tackle these challenges in a three-year programme (Jan 2019–Mar 2022) that aims to develop and demonstrate new approaches, with initial implementations of Black Start service from DER from mid-2022 if deemed feasible and cost effective. Case studies on the SP Distribution (SPD) and SP Manweb (SPM) networks will be used to explore options, then design and test solutions through a combination of detailed off-line analysis, stakeholder engagement and industry consultation, desktop exercises and real-life trials of the re-energisation process.

Project description
The project is made up of five workstreams. The Project Direction and Knowledge Dissemination workstreams cover the effective management of the project and sharing of learning. The other three workstreams cover the wide range of issues to enable Black Start services from DER.

- The **Power Engineering and Trials (PET)** workstream is concerned with assessing the capability of GB distribution networks and installed DER to deliver an effective restoration service. It will identify the technical requirements that should apply on an enduring basis. This will be done through detailed analysis of the case studies and progression through multiple stages of review and testing to achieve demonstration of the Black Start from DER concept in 'live trials' on SPEN networks. Initial activities have focused on reviewing technical aspects of DER-based restoration in a number of case study locations that will support detailed analysis and testing within the project. Each case study is built around an 'anchor' resource with 'grid forming' capability, i.e. the ability to establish an independent voltage source and then energise parts of the network and other resources. Then it is intended that additional DER (wind, solar and batteries), if available, will join and help grow the power island, contributing to voltage and frequency control. The ultimate goal is to establish a power island with sufficient capability to re-energise parts of the transmission network and thereby accelerate wider system restoration.
- The **Organisational Systems and Telecoms (OST)** workstream is considering the DER-based restoration process in terms of the different roles, responsibilities and relationships needed across the industry to implement at scale. It will specify the requirements for information systems and telecommunications, recognising the need for resilience and the challenges of coordinating Black Start across a large number of parties. Proposed processes and working methods will be tested later in the project in desktop exercises involving a range of stakeholders.
- The **Procurement and Compliance (P&C)** workstream will address the best way to deliver the concept for the end consumer. It will explore the options and trade-offs between competitive procurement solutions and mandated elements. It will make recommendations on the procurement strategy, aiming to be as open and transparent as possible while reflecting wider industry discussions on related topics like whole system planning and the development of distribution system operator (DSO) functions. It will feed into business as usual activities to make changes as necessary in codes and regulations.

For an overview of the project and current progress click on the link **here** for the *Distributed ReStart Progress Report – June 2019*.

Executive summary

This report is the first deliverable from the Distributed ReStart project and outlines the technical findings to date within the power engineering and trials (PET) workstream. The initial options stage of the workstream seeks to identify the main technical challenges that exist when considering the concept of Black Start services from distributed energy resources (DER).

In order to provide a holistic understanding of the practical viability, the workstream must consider all technical elements and functionality required to establish a restoration process from DER. This first report also discusses initial thinking on the testing requirements and the potential for roll-out throughout all GB DNO networks.

Key findings

From thorough analysis of the power engineering challenges we face, it is the conclusion of this report that Black Start from DERs is potentially viable from a power engineering perspective. Key issues are highlighted but are not considered prohibitive to project continuation.

- **Viability –** A thorough analysis of the existing technical capability of DER and distribution networks has shown that, while there are many challenges to overcome, potential solutions exist such that providing Black Start services from DER is potentially technically viable on a GB-wide basis. The project should proceed in order to fully address all the issues which have been identified, and develop comprehensive technical solutions which will enable this new service.
- **Functional and testing requirements –** It is likely that the functional and testing requirements for DER Black Start providers will be a hybrid solution of the existing requirements (typically for large transmission connected power stations), taking into account the technical capability of the DER, the configuration of the distribution networks, and the overall technical solution implemented to provide the service.
- **GB roll-out –** Analysis of all DNO long term development statements (LTDS) has shown that, across GB, there is 4 GW of generation currently connected at 33kV which may be considered as having the potential to initiate a distribution power island (anchor generation). This capacity would approximately double should all currently contracted generation proceed to connection.

Case study criteria and selection

The technical assessment is primarily based on ten case studies featuring selected sample areas of the SP Distribution (SPD) and SP Manweb (SPM) networks. An eligible case study must contain at least one grid forming generator (i.e. with the ability to establish an independent voltage source), that could be used as an ‘anchor’ in a power island (connected at 33kV, 132kV or 11kV transforming directly to a higher voltage). Based on current technology connected to the distribution networks, a synchronous generator is required. Based on this selection criteria, case studies have been chosen with a variety of DER, network topologies, network characteristics and restoration options to provide learning on a GB-wide basis.

Assessment of Black Start from DER viability

Based on the selected case studies and through DER stakeholder engagement, a qualitative assessment of existing DER technical capabilities has been undertaken to assess the barriers and limitations associated with providing a Black Start service, and propose potential solutions.

Issues register

To provide a consistent method for capturing the main technical challenges, the report has utilised an issues register, the purpose of which is to record the main technical barriers and limitations, detail the challenges surrounding the issues, and provide potential solutions which may be implemented to resolve the issues. A Red/Amber/Green (RAG) status reporting method has been applied to detail the severity of each technical issue, (red indicating an issue which may require a prohibitive amount of work to overcome or may not be solvable).

From the project learning to date, no technical issues have been identified which would prove insurmountable to the concept of providing Black Start services from DER across GB. Whilst this is a positive outcome, and encourages the further advancement of the project throughout all workstreams, many technical challenges do exist which will require further exploration in future stages of the project. The complete issues register is given in the Appendix of this report (Appendix L – issues register).

DER technical capability

Throughout the stakeholder engagement process there was an encouraging willingness expressed by DERs to both participate within the assessment and explore methods to become technically compliant. Currently, there are several DER technologies that are physically capable of providing the necessary control with some modifications.

The following has been identified from the outcomes of the assessment.

- Most anchor generators will require a minimum load in order for them to start safely. A load bank is likely to be required to provide this (in incremental steps) when in island mode due to the limited block load capability of the DER.
- The anchor generator will be required to provide frequency and voltage control; most will need this capability installed or enabled.
- A minimum fault level will be required for converter connected generation (e.g. wind farms) to connect. This may not be available on a power island supplied by DER, and manufacturers would have to confirm if alternative control settings can be applied for lower fault level operation.

DER resilience

- It is understood some DER sites have standby generation installed which will provide several days' resilience; however, on several DER sites the auxiliary back-up supply will only last for a few hours (battery back-up only), ensuring that the generation will be safely shut down.
- The vast majority of anchor generators do not have sufficient standby generation for self-starting, although methods can be put in place which will provide this service.
- It has been recognised that wind farm developers will typically require a 33kV supply within roughly six hours in order to maintain auxiliary turbine supplies and avoid gearbox oil cooling (which can result in several days being required to pre-heat and restart all turbines).
- Wider implications have also been found where some DER technology types will require a relaxation of their normal emissions limits to achieve the operating profile required for Black Start services.

Distribution island – technical considerations

Due to their size and limited generation resources, power islands have different electrical characteristics compared to a large power grid. The main issues identified are:

- low fault level
- low system inertia
- voltage control at 33kV (normally provided by the grid transformers)
- high variability of load and generation.

These result in a number of operational challenges such as voltage control, protection adequacy, and frequency stability. The project has identified a variety of potential solutions to these issues.

Distribution island – operational considerations and automation

The technical and operational challenges associated with establishing, growing, maintaining and restoring a distribution (33kV) power island have been reviewed. Given these issues, and the limited human resources (e.g. control engineers) that may be available at the time of a Black Start, the application of automation in the form of a control system is discussed for each stage. Mitigation options and potential solutions have been identified, and will be explored further in the next stage of the project. For example, to accommodate the limited block load capability of the DER, a control system may be required to simultaneously switch in demand and switch out a load bank to minimise the net demand change imposed on the generator.

Distribution island – restoration strategies

Initial restoration strategies are discussed in terms of minimising the inrush current effects associated with energising a grid (132/33kV) transformer, minimising the loading and voltage issues associated with energising a primary (33/11kV) transformer, and the priorities for the restoration (e.g. supplies to a wind farm to maintain the turbine auxiliary supplies).

Wider restoration options are considered for expanding a 33kV power island. These include:

- synchronising with/or creating an adjacent 33kV power island through 33kV interconnection
- back energising a grid transformer and connecting additional DER at 132kV
- energising an adjacent grid 132/33kV substation from the 'top down'
- energising to the 275kV or 400kV network.

Distribution network

Earthing and protection

Key findings from the technical analysis of existing practices for earthing and protection are as follows:

- A 33kV power island will require a new method of earthing (the existing earthing transformers are connected to the grid transformers and will be disconnected from the system). The Electricity Safety, Quality and Continuity Regulations (ESQCR) require a network to be connected to earth "at or as near as is reasonably practicable to the source of voltage".
- A new 33kV earthing transformer will be required at most anchor generation installations. An alternative would be for all future potential anchor generators to have a switchable earth connection on their generator transformer 33kV winding.
- LV protection will operate as normal as long as the fault level at the grid substation 33kV busbar is at least approximately 30MVA. This should be achievable for most anchor DER connected to the 33kV network.
- There may be insufficient fault infeed for all existing 11kV, 33kV and 132kV protections to operate adequately. This can be overcome by having separate protection relay settings for Black Start. Additional relays, or relays changed with modern equivalents which can accommodate a second settings group, may be required.

Power system studies

Preliminary power system studies were undertaken on several of the case studies (in SPD and SPM). Voltage profile, voltage step change, load flow, transformer energisation and generator reactive capabilities were assessed. Some scenarios are highlighted where high and low voltages, excessive voltage dips or generator reactive capability issues may arise. These are not deemed to be critical issues with potential solutions being proposed. The splitting of meshed networks, predominately in SPM where substations may be interconnected at several voltage levels, was also highlighted as a potential issue given the requirement to establish restoration paths for Black Start.

Resilience

- Before a Black Start, it is necessary to ensure all substations are safe to energise. This means that essential elements such as protection, control and supervisory control and data acquisition (SCADA) are available. These systems are powered by batteries, with an LV supply for charging, which may also provide motive power for equipment such as tap change motors and circuit breaker spring charging where required.
- The current baseline requirement is that all core transmission and distribution substations are designed for 72 hours' resilience. However, some existing substations may only be resilient for ~18 hours (the life of the batteries with no LV supply).
- For each power island, a survey will be required to ensure the required resilience at the key substations. This may be provided by additional battery capacity, battery demand disconnection schemes, and/or standby generation.
- DNO resilience and asset management policies may need to be amended to reflect the requirements of Black Start from DER in the future.

Live trials update

The original intention outlined in the project bid document was for 'full' live trials to take place during 2021. After consideration of various factors, it has been agreed a more realistic approach will be to undertake testing on a more measured, staged approach. This will mean testing individual elements of the start-up process separately. To achieve a similar output within the initially proposed timescales, testing is required to commence earlier with the proposal to start in 2020 with DER self-starting and frequency response tests.

Initial proposals for functional and testing requirements

This section gives an overview of the existing Black Start functional requirements for providers in GB; where the ability to start up independent of external supplies, energise part of the transmission network and block load local demand is required.

It also includes the procurement approach, including recent developments where a number of parties are allowed to form a partnership or consortium to meet the outlined technical requirements, where one single provider cannot meet all of these on its own. The functional requirements for Black Start from DER may retain the main principles that the present requirements outline, however:

- some specific quantities may be modified to reflect the capabilities of smaller and more distributed generators and other energy resources
- consideration is also given to the possibility that some of the technical requirements (e.g. block load capability) are applied to the distribution island as a whole, with multiple resources being coordinated, as opposed to potentially onerous requirements being placed on a single DER.

The current approach to Black Start testing and assurance is described, including the use of real-life tests, assurance visits and desktop exercises.

It is likely that testing to ensure Black Start from DER readiness at all times will be a hybrid solution of what is currently done and whatever new testing arrangements are proposed by the project, which will depend on the final functional requirements.

At this stage, a number of areas in which the DER-based approach is different from the current approach is highlighted, including:

- greater number of parties involved
- DNOs will play a bigger role
- greater diversity in resources
- the need to test multiple DER and the network together, ideally including demand customers (which may not be practical)
- more complex outages across distribution and transmission will be required
- the need for new telecommunications and control systems.

To meet these challenges and mitigate some of the risks associated with the Distributed ReStart approach some preliminary proposals on testing have been made that include:

- testing during commissioning and outages
- a statistical approach with sample-based testing
- greater use of modelling and simulation, both to minimise the need for real-life testing and to support training and other aspects of Black Start assurance
- possible use of temporary operation in power island mode, which would demonstrate important aspects of DER and network capability without interrupting customer supplies
- scope for third party involvement in testing.

The next stage of the project will explore these options, assess them jointly across all project workstreams, and consult widely to decide on a suitable approach to testing.

The potential for roll-out of the method across GB

An estimation of the potential for concept roll-out of Black Start from DER across the remaining DNOs in GB has been made using the information published within the DNO long term development statements (LTDS).

A breakdown of this generation mix and associated connection voltage is displayed below.

Voltage	Current estimated anchor generation	Current estimated additional DER generation
11kV	1 GW	1 GW
33kV	4 GW	11 GW
132kV	4 GW	2 GW

It can be seen that there is 4 GW of anchor generation currently connected with the potential to establish power islands at 33kV. This consists of 249 individual 33kV generation sites out of a total of 350 (including 11kV and 132kV anchor generators).

The analysis also considered a number of future scenarios where both 50 per cent and 100 per cent of the current contracted generation is included.

Future scenarios	Anchor generation	Additional DER
Existing	9 GW	14 GW
50% contracted	13 GW	18 GW
100% contracted	17 GW	22 GW

The 17 GW anchor generation, based on current connected and all contracted generation, consists of ~9 GW at 33kV.

Within the GB DNO LTDS data, there is ~10 GW of generation (connected and contracted) which is classified as 'other' or 'mixed'. As a result, it is has not been possible to determine the proportion of this generation which may be applicable to Black Start and if it is anchor generation or additional DER.

Chapter 1

Introduction

Introduction

1.1 Industry engagement

This project aims to incorporate the views of wider industry at every opportunity, bringing in the diverse expertise found across multiple businesses in the electricity market to solve this world first challenge of providing Black Start services from DER. The project has sought to achieve this through consultations with multiple DNOs, webinars and conferences with wider audiences and has established a stakeholder advisory panel to scrutinise the outputs throughout this three-year project.

1.1.1 DNO consultation and review

A wide variety of case studies have been selected to ensure that there are opportunities to explore a diverse range of circumstances and the learning is as applicable on a GB-wide basis as possible. Moreover, a review of all other DNO LTDS has been undertaken to ascertain any omissions in terms of factors such as network configurations, voltage control methods, earthing and protection.

1.1.2 Case study selection

Furthermore, the approach to case study selection has been validated through a webinar on 29 March 2019, reaching over 100 engaged stakeholders through this format and taking questions which have subsequently been published. This webinar was an important step in the first stage of the project, ensuring that the technical foundation for the project is developed in conjunction with the wider industry.

Subsequently, these case studies have been discussed at Utility Week Live and the Power Responsive conference to reach broader industry stakeholders. Additionally, initial contact has been established with all potential anchor generators in the case studies to establish interest and capability.

1.1.3 Continued engagement

The project continues to reach out to a broad stakeholder base and is actively seeking ways to engage with business of all sizes. This is being done through project updates, the Stakeholder Advisory Panel Forums and industry advisory groups. The above is represented in the Stakeholder and Engagement Plan which details cadence and approach with the different areas of interest.

Through these events, a strong industry interest in the project has been established, reaching over 300 registered interested parties across a diverse range of businesses.

1.2 This report

The first stage of the PET workstream is the Options Stage (between January and July 2019), which is primarily a qualitative assessment of the networks and DER to support making a preliminary assessment of the viability of Black Start from DER.

Initially, an understanding is given of the case study selection criteria and the ten case studies upon which the project is based. This is followed by an assessment of the viability of Black Start from DER. As part of this, the ‘issues register’ is introduced, followed by consideration of the technical capability and resilience of the DER. The issues associated with establishing a distribution island are then analysed, under the headings of technical considerations, operational considerations and automation, and restoration strategies. The DNO network is then examined looking at the earthing and protection requirements, power system studies, and network resilience.

The existing functional and testing requirements for Black Start providers are discussed, along with proposals for how these may be relaxed or modified to apply to DER. An assessment is then given of the potential for roll-out of DER Black Start services across GB based on an analysis of all GB DNO networks and the capacity of DER currently connected and contracted.

The overall conclusions from each section of the report are then given, followed by an overview of the next steps, including an update on the potential live trials, for the PET workstream.

Chapter 2

Case study criteria and selection

Case study criteria and selection

2.1 Introduction

As outlined in the project bid document, the first tasks within the PET workstream were to define the criteria to be used for selection of case studies then apply these across the network to arrive at a limited number of suitable case studies. This was done through careful consideration of all aspects and ratified through stakeholder engagement. It is also the objective to select case studies only for analysing and testing within the project. It is important to appreciate this work will not lead to direct contracting for Black Start services with any associated DERs and any such commercial arrangements will be subject to fair and open procurement.

Analysis of the SPD and SPM networks was undertaken to identify all areas that met the essential case study criteria defined below, with ten areas then selected. Each one presents a different range of challenges, technologies and potential to unlock value for the consumer. Through selecting a diverse range of network configurations and DER technologies, any enduring solution should be applicable on a GB-wide basis.

2.2 Case study criteria

2.2.1 DER-related criteria

Each case study requires at least one anchor generator, defined as a generator with the ability to establish an independent voltage source (grid forming capability). At this time, based on what is currently connected to distribution networks in GB, this means each case study will be built around at least one synchronous generator (these may be powered by a number of sources including gas, diesel, hydro and waste). The intention is to energise predominately at 33kV, however, a case study may contain an anchor generator connected (or connecting in 2019) at 33kV, 132kV or 11kV transforming directly to a higher voltage. These requirements are referred to as the 'essential case study criteria'. During the three-year course of this project, other technologies may be developed and connect with sustainable grid forming capability (e.g. batteries), and if so they will also be considered as anchor generators as project timescales allow.

Converter-connected resources (like wind, solar PV and batteries) on GB networks today are primarily grid following, and can operate only if there is a voltage on the network that they can observe and follow. The opportunities for these types of DER to join and help grow the power island is recognised, including their ability to contribute to voltage and frequency control. The case studies should therefore include a variety of these additional DERs that could be energised by the anchor resource and support further system restoration.

2.2.2 Network-related criteria

The case studies are required to cover a range of different network conditions to ensure the broadest applicability of project learning across all of GB. Strict criteria, based on network characteristics, have not been applied in selecting case studies, however a range of network types (e.g. urban or rural), network topologies (e.g. radial or meshed) and characteristics that represent varying degrees of challenge are included. This will enable the project to reveal, through detailed analysis, the practical limits of DNO networks in the provision of Black Start.

A number of these case studies will progress to the live trial stage. Therefore, the essential criterion at this stage is the capability to take an outage (containing the relevant DER and network) for the trial to proceed without disconnecting supply to customers. As the project progresses, the suitability of each case study will be further assessed. Whilst a live trial allows us to demonstrate the individual functionalities in practice, it is not essential that all case studies progress to this stage, as much of the learning will come from the off-line analysis, stakeholder consultations and desktop exercises.

2.3 Case study selection

Across the 15 supergrid groups feeding the 132kV network in SPM (and associated 33kV groups), and the 65 grid supply points (GSPs) feeding the 33kV network in SPD, analysis was undertaken to identify all areas that met the essential case study criteria (i.e. had an appropriate anchor generator), with ten areas then selected as the case studies on which the viability of Black Start from DER will continue to be assessed.

2.3.1 SPD

In SPD, twenty areas of the network, predominantly 132/33kV GSPs)were identified as meeting the essential case study criteria. Six of these areas have been selected as proposed case studies. Four of these case studies contain the largest MW capacity of anchor generation (along with a significant capacity of additional DER), with the other two being selected based on providing the desired variety of studies. The Meadowhead case study has generation transforming directly from 11kV to 132kV, and the Portobello case study is a largely urban network being adjacent to Edinburgh city centre.

2.3.2 SPM

The SPM network is considered in three geographic regions: Cheshire, Mersey and Wales. In Cheshire, there are six 132kV groups (each containing associated 33kV interconnected networks). In this region, most of these 33kV groups contain at least one anchor generator. The Sankey Bridges 33kV group (connected to the Carrington 132kV group) has been selected as a case study as it contains three potential anchor generators, is adjacent to another 33kV group with multiple DER, and provides the potential to study the interaction with a 138 MW combined heat and power (CHP) generator connected at Carrington 132kV.

In Mersey, there are three 132kV groups. The Bootle 33kV group (associated with the Kirby 132kV group) is proposed as a case study, having the largest capacity of anchor generation connected and includes intermittent generation whilst providing the opportunity to study an urban 33kV network.

In Wales, there are six 132kV groups, with only one not having an associated 33kV group with an anchor generator. The Legacy 33kV network has been selected as a case study (supplied from the Legacy 132kV group). This has an anchor generation alongside thirteen intermittent DER already connected (including solar). In addition, the Maentwrog 33kV network has been selected (in the Trawsfynydd 132kV group) as it provides the opportunity to study hydro generation as the anchor, interacting with wind and solar DER. Both the Welsh case studies provide the opportunity to study the issues associated with a rural network.

2.4 Case study proposals

The ten proposed case studies are summarised in table 2.1. These provide an opportunity to study:

- a variety of anchor generator types (including hydro, biomass/CHP, energy from waste, gas, diesel and combined cycle gas turbines (CCGT))
- a variety of 'additional DER' types (wind, solar and batteries)
- varying proportions of anchor generation capacity in relation to additional DER capacity
- varying network topologies: radial and meshed
- varying network types: rural and urban
- anchor generation connected at 11kV, 33kV and 132kV
- establishing power islands at 33kV
- synchronising between two interconnected 33kV power islands
- energising from a 33kV power island up to the 132kV or 275kV network
- energising from the 132kV network (supplied by a 132kV anchor generator or back energised from 33kV or 11kV generation) down to the 33kV network.

From a high-level assessment of outage requirements, all case studies detailed in this report are considered viable for participating in a live trial.

2.5 Case study description, data and diagrams

A description of each case study is given in Appendix A – case study descriptions.

Schematic diagrams for each case study have been produced to give an overview of the distribution and transmission networks associated with the DER. Figure 2.1 shows the schematic diagram for case study No.1 (Galloway region). The schematic diagrams for all of the case studies are contained in Appendix B.

In addition, for each case study, a data sheet has been produced listing the location and capacity of the anchor generator(s), and the additional DER locations and capacities that may be used to grow the power island. In addition, the generation directly connected to an 11kV busbar has been recorded as an indication of the level of generation connected at this voltage. While this 11kV generation will not be used directly in restoration, it may help to support a power island when the 11kV network is energised. Demand data has also been recorded. The data sheets are provided in the Appendix (Appendix C – case study data sheets).

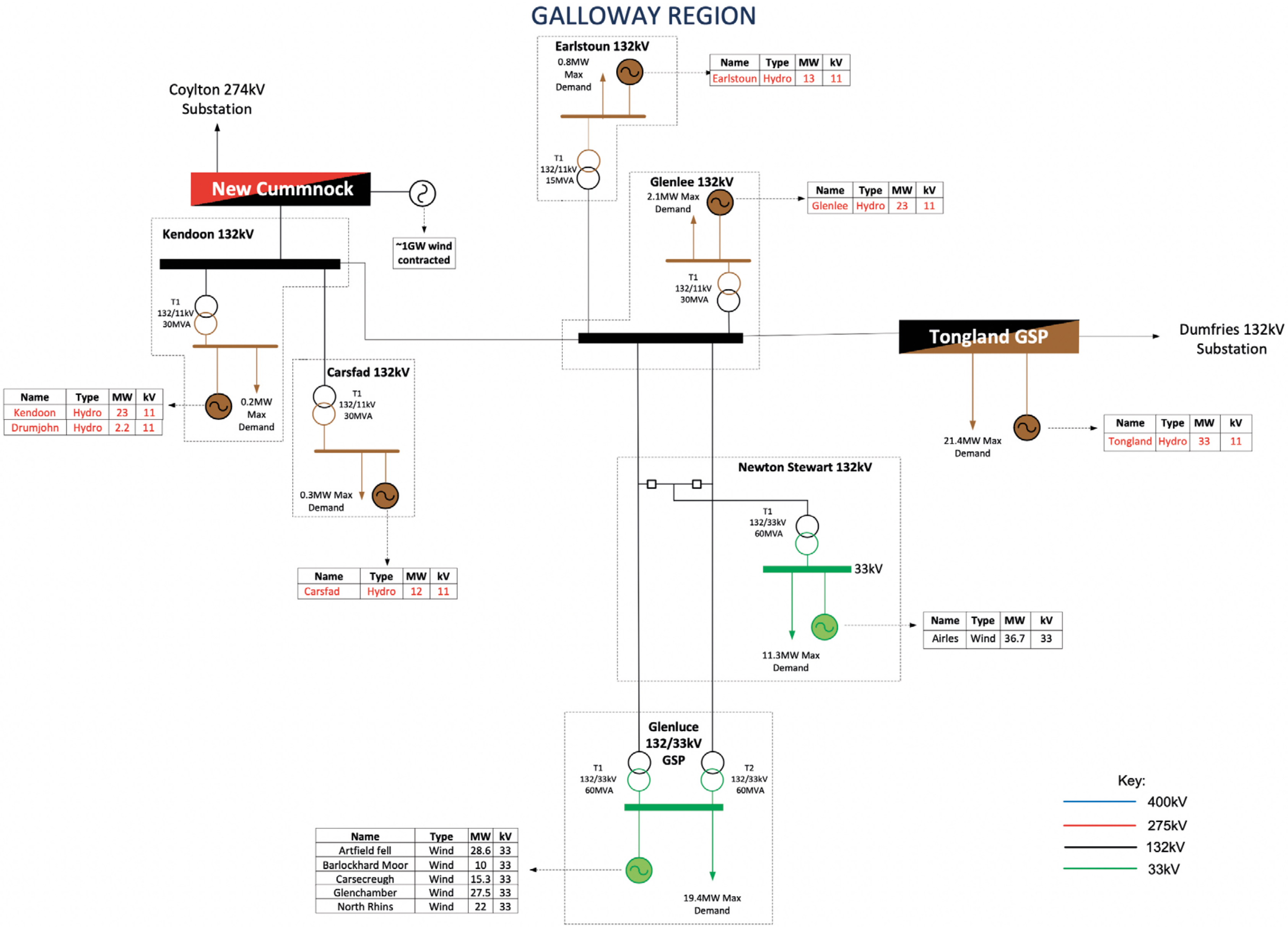
Table 2.1
Case study selection summary (includes generation connected or connecting in 2019)

Case study No.	Network name	Total generation capacity[1] (MW)	Anchor (MW)	Additional DER (MW)	Network topology	Case study summary
1	Galloway Region (SPD – Dumfries)	224	81	140	Radial – 132/33kV	• Energise the 132kV network directly from 11kV connected hydro generators. • Energise two 132/33kV GSPs (Glenluce and Newton Stewart) to connect demand and intermittent generation and establish a power island. • Energise to New Cumnock 275/132kV substation where in excess of 1 GW of wind generation is contracted.
2	Glenrothes GSP (SPD – Central and Fife)	165	112	29	Radial – 275/33kV	• Establish a power island at Glenrothes GSP utilising Markinch CHP biomass plant (55 MW) with the potential to interconnect at 33kV to two adjacent GSPs (Westfield and Redhouse). Westfield also contains anchor generation, thus the potential exists to synchronise two power islands together. (Contracted installation of battery energy systems (BES) at Glenrothes and Redhouse GSPs in 2019).
3	Chapelcross GSP (SPD – Dumfries)	137	45	79	Radial – 132/33kV	• Establish a power island at Chapelcross GSP using a biomass generator as the 'anchor' along with wind generation. • Long rural network (~40 km 33kV circuits), DER connected by long 33kV cable circuits (anchor gen ~25 km cable). • Back energise the 132kV network and synchronise with the National Grid Electricity Transmission (NGET) at Harker 132kV substation.
4	Dunbar GSP (SPD – Edinburgh)	166	41	118	Radial – 132/33kV	• Approximately 30 per cent ratio of anchor generation (energy from waste) to additional DER (wind). • Back energise the 132kV network to Torness nuclear power station. • Possibly synchronise with Cockenzie and Portobello to provide a 33kV power island across a wide area.
5	Meadowhead (SP Transmission – Ayrshire)	158	32	100	Radial – 132/33kV	• Energise 132kV network from an 11kV CHP generator. • Establish a power island with Saltcoats 132/33kV GSP and its additional DER (predominantly wind). • Energise the 132kV network to Hunterston nuclear power station.
6	Portobello GSP (SPD – Edinburgh)	30	15	0	Radial – 275/33kV	• Establish a power island from an energy from waste generator to pick up demand/embedded 11kV generation. • Interconnection to adjacent 33kV networks. • Back energise to 275kV.
7	Bootle Grid (SPM – Mersey)	53	35	18	Mesh –132/33kV	• Urban network (Liverpool). • Establish a power island from 35 MW CHP anchor; 18 MW wind.
8	Legacy (SPM – Wales)	190	37	126	Mesh – 132/33kV	• Rural network with 37 MW anchor (2 sites, diesel and gas). • ~100 MW additional DER including ~40 MW solar.
9	Sankey Bridges (SPM – Cheshire)	287	281	4	Mesh – 132/33kV	• Supplied from the Carrington/Fiddlers Ferry 132kV group which has a 138 MW CHP at Carrington. • Opportunity to energise up to the 132kV or down from the 132kV to 33kV. • Opportunity to synchronise with adjacent 33kV group (Elworth has 48 MW CCGT).
10	Maentwrog (SPM – Wales)	103	39.8	46	Mesh – 132/33kV	• Additional DER mixture of wind and solar. • 40 MW anchor (hydro).

[1] Includes 11kV generation directly connected to an 11kV busbar as recorded in the case study data sheets (Appendix B – case study diagrams).

Figure 2.1

Case study No.1 (Galloway Region) schematic diagram (anchor generation shown in red)



Chapter 3

Assessment of Black Start from DER viability

Assessment of Black Start from DER viability

3.1 Introduction

An initial assessment of the technical viability of providing Black Start from DER, considering the issues associated with the DER, establishing and maintaining a distributing island, and the distribution network, has been undertaken. This has primarily been based on the case studies along with stakeholder engagement.

In order to assess the technical viability of Black Start from DER, each section of this report summarises challenges and potential solutions in the issues register (as shown in table 3.1). The issues are split into categories, along with a description of the issue, and the challenges related to providing Black Start from DER.

A traffic light symbol is used to identify the criticality of the issue. A green light indicates an issue which is anticipated to have a relatively simple solution.

An orange light represents an issue requiring more works to overcome, but the potential solutions are not anticipated to be so onerous that they would act as a project blocker. A red light depicts an issue which does not have an identified solution or where the solution may be prohibitive from a technical or economic perspective. Red issues will require specific further analysis in later project stages or potentially represent a restriction on where or how Black Start can be facilitated by DERs.

The issues register will ensure that all concerns related to the viability of the enduring solution or the project are recorded and form a basis for future works to ensure that all issues are addressed. This log will represent an ongoing analysis process throughout the project as further challenges are identified and addressed. The complete register of issues identified in this report is given in Appendix L – issues register.

Table 3.1
Issues register template example

Issues Register					
Category	No.	Description	Black Start DER Challenges	Potential Solutions	

3.2 DER technical capability and resilience

3.2.1 Case study DER assessment

The anchor (synchronous) and additional (non-synchronous) DER in the ten case studies (64 DER in total), were contacted to introduce the Distributed ReStart project, and to answer a questionnaire assessing the technical capability and Black Start resilience of their developments. To date approximately 40 per cent of the DER developers have responded and provided information. The questionnaire used is contained in Appendix D – stakeholder engagement questionnaire.

3.2.1.1 Case study anchor generation

The results from surveying the anchor generators are given in Appendix E – case study anchor generation survey. The relevant issues are summarised in the issues register shown in table 3.2.

Table 3.2
Case study anchor generation issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DER Technical	T6	Most anchor generator types need a minimum demand to start with (to avoid overheatng the boiler or turbine blade cavitation). This ranges from ~20% to 50% of rating.	It is unlikely this demand can be provided from the network due to: i) the uncertainty of demand being connected, ii) the demand exceeding the gen load pick up capability.	Start the gen against a load bank, or utilise a battery if available.	
DER Technical	T5	DERs have different control methods. Some manned 24/7, others are fully remote controlled and others a combination.	Resilient control of the DER from Black Start will have to be developed taking into account all current control methods.	This issue will be investigated by the Organisational Systems and Telecommunications workstream.	
DER Resillience	DR1	Varying capacities, and sustainability, of auxiliary backup supplies. Some battery backup only. Others limited standby gen (e.g for essential services and/or to protect the turbine).	Auxiliary power required to maintain availability of gen (e.g protection, comms, keep boiler warm) and to be able to self start (typically 10-15% of MW rating required).	Install the required capacity of auxiliary power (e.g diesel gen) for self-starting, with suitable changeover scheme with normal site aux supplies.	
DER Resillience	DR2	Generators utilising a combustion process (e.g EfW) must control their operation (e.g ramp rates) to keep within emissions limits.	The operation required for black start (or the project live trials) may result in the generator emissions limits being exceeded.	Procurement and Compliance workstream to seek resolution of this issue with the relevant authorities.	
DER Resillience	DR3	Fuel stores are typically in the order of several days. For some ash disposal may be an issue after several days.	A suitable resilience timeline for DER types will need to be defined.	DERs may be able to change their operating regimes to meet increased operating times for Black Start.	
DER Resillience	DR4	A licence condition of certain generators is that they do not discuss Black Start in public documents (e.g planning applications).	A DER may have to make modifications for Black Start which would normally require public disclosure of the reason.	Clarification required of this licence condition applicability to DER and how it may be removed or mitigated.	
DER Resillience	DR5	A DER receiving Renewable Obligation Certificate (ROC) payments requires Ofgem approval to any changes tp their electrical Single lIne Diagram (SLD).	Changes to a DER SLD may be required to make them resilient and self-starting	Issue to be resolved with Ofgem.	

3.2.1.2 Case study additional DER

The results from surveying the additional DER surveys are given in Appendix F – case study additional DER survey.

The relevant issues are summarised in the issues register shown in table 3.3.

Table 3.3

Case study additional DER issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DER Technical	T7	Wind farm, battery and solar sites are typically not permanently manned and are controlled remotely.	Direct control of the DER may be required as part of an islanding control scheme (i.e not via a remote control room).	This issue will be investigated by the Organisational Systems and Telecommunications workstream.	
DER Technical	T8	Some wind farms require to start at ~10% of its rated output.	The network to which it connects must be capable of absorbing the minimum wind farm export power.	The MW control scheme for the island, or anchor DER, should be able to accommodate the minimum MW output of a wind farm when connected.	
DER Resillience	DR7	Wind turbines receive their auxiliary supplies (e.g for heating) from the incoming 33kV supply. After ~6 hours outage the gear box oil may have cooled too much to allow restarting (depends on ambient temperature).	If the DNO connection is not restored to a wind farm within ~6 hours it may take days to restart due to the turbines having to be individually pre-heated.	Plan the DNO restoration strategies such that supplies are restored to wind farms as a priority. Contract that a WF has to install back up generation capable of supplying each turbines auxiliary load.	
DER Resillience	DR6	Varying capacities, and sustainability, of auxiliary backup supplies. Some battery backup only (e.g for telecoms and protection). Others limited standby gen to maintain essential services for several	It may not be possible to communicate with the site, or reastart after a Black Start if the essential services back up supplies are not adequate.	Install the required capacity of auxiliary power (e.g diesel gen) for self-starting, with suitable changeover scheme with normal site aux supplies.	
DER Resillience	DR8	A hard trip (not ramping the output down) stresses the wind turbines and they are then more prone to faulting and not reconnecting.	The relative voltage and frequency instability of a power island may result in a wind farm disconnecting more often.	The island control scheme should be designed to avoid hard trips of a wind farm where possible.	

3.2.2 Supplementary DER technical issues

The following is an overview of additional technical issues which have been identified related to the provision of Black Start from DER.

3.2.2.1 Converter connected generator stability

Converter connected generation utilises voltage source converters which 'follow' the existing system voltage using a phase locked loop (PLL) process to synchronise with the system voltage. On a distribution power island with low fault levels and inertia, the network voltage will be more dynamic which can lead to the PLL losing track of the voltage, risking damage to the equipment and loss of the generation. The main issues are:

- potential PLL instability on weak power networks (voltage waveform can be highly variable during disturbances)
- a minimum fault level is required for normal operation of converter connected generation (this needs to be determined and demonstrated by the manufacturer).

3.2.2.2 DER frequency control capability
Fast acting frequency control is required to operate a stable power network. Under Grid Code, all large power stations must maintain provision for this through either Limited Frequency Sensitive Mode (LFSM) or Frequency Sensitive Mode (FSM). However, most smaller DERs are not subject to these Grid Code requirements, instead their technical requirements are contained in their DNO Connection Agreement. For Scotland, England and Wales there has been no DNO requirement to provide frequency control. A DER still requires governor control, but this typically operates in base load (MW) control.

Moreover, a DER which is subject to these regulations is unlikely to be operating with their continuously acting frequency control mode enabled and would use LFSM which only responds to a frequency deviation in excess of 50.4 Hz.

As a power island would require independent means of frequency control it follows that frequency control systems may have to be installed or altered retrospectively on selected DER, or an alternative means of controlling the power island frequency developed. An alternative to FSM may be isochronous control whilst there is only a single generator controlling the frequency. Isochronous control seeks to maintain a set speed of rotation with loads accepted or rejected as the generators MW capability allows. This is only suitable for a single generator because it does not facilitate load sharing and would cause instability during parallel operation but may be beneficial during power island initiation.

For DER connecting after 27 April 2019, the technical requirements are now as specified in Engineering Recommendation G99. This divides the technical requirements of DER into four capacity categories:

Type A – 11 kW to 1 MW

Type B – 1 MW to 10 MW

Type C – 10 MW to 50 MW

Type D – 50 MW and greater

Types C&D require to contribute to frequency control. This will ensure that going forward all DER connecting, 10 MW and above, have a fast-acting frequency control device. Type B should also have the capability to respond to low and high frequencies, known as LFSM. This means structuring the enduring solution to meet these new regulations will prevent significant changes being needed on new plant but may require retrofit to existing DERs.

3.2.2.3 DER voltage control capability
A generator can operate in one of the following voltage control modes:

i) Constant voltage control

ii) Slope (droop) voltage control

iii) MVAr control

iv) Power Factor control

In Scotland, the DNO Connection Agreements require that a synchronous generator operates in constant voltage control at its generator terminals (this equates to droop control considering the impedance of the generator transformer). A non-synchronous generator operates in droop voltage control. Either of these modes would be required where DER is controlling the voltage in island operation.

In England and Wales, power factor control is usually stipulated in the Connection Agreements (typically a generator is requested to operate near unity power factor). The DNO's connecting circuit may have been designed on this basis such that to change to droop or constant voltage control (where the power factor will vary), the voltage limits or thermal rating of the network may be exceeded. Thus, the feasible operating range of any DER may depend on network limitations as well as the DER itself.

In the future, Engineering Recommendation G99 (for DER connecting after 27 April 2019) means that all Type C and D will provide continuous steady state control of the voltage at the connection point with a set point and slope characteristic, the final proposal should take account of these variations in voltage control methods.

3.2.2.4 DER technical issues register
Table 5 shows the addition to the issues register related to the supplementary DER technical issues. The key items of challenge include the sensitivity of converter connected generation to low fault levels present on a distribution island, and the lack of DER dynamic models available.

Table 3.4
DER technical issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DER Technical	T1	Converter connected generation is sensitive to low system fault level and resulting voltage instability.	The fault level might not be sufficient to allow converter connected gen to stably connect. Control settings may need changed for Black Start scenario. The gen may trip for system disturbances.	Power system analysis/manufacturer modelling required to determine minimum fault level for operation and stability. Provide suitable mechanism to change converter control settings for Black Start.	
DER Technical	T2	Dynamic models not available for DER (unless large as defined in the Grid Code). The dynamic models for DER (if available) or the generic dynamic models may be suitable for normal operation only and not for Black Start related simulations	Dynamic response required to know key parameters such as the block load capability (for synchronous generators).	Request the developer provide a dynamic model suitable for Black Start simulations. Carry out an initial 'live trial' with relevant gen to ascertain the dynamic f control load response of sync gen, or MW output response time of converter connected.	
DER Technical	T3	Most existing DER normally operates in base load (MW control), and may not have frequency control installed (unless a Grid Code large power station).	Frequency control is required on at least one anchor gen when operating in an island.	Install/enable frequency control as required on anchor gens to operate in a Black Start scenario. Assess using local freqency control for converter connected gen compared to a microgrid controller to control the MW output.	
DER Technical	T4	DER in England & Wales typically operates in power factor control	Voltage control is required on at least one anchor gen in an island. Gen control modes may need to be changed for Black Start. The DNO connection may not be suitable for V control.	Install voltage control as required on anchor gens. Provide suitable mechanism for changing excitation control options. Study the DNO connection to ascertain if suitable for V control. Consider limiting MW o/p of gen if thermal/voltage issues.	

3.2.3 Conclusion for DER technical capability and resilience

This section has provided an overview of the technical capability and resilience of DER, related to Black Start from DER, through stakeholder engagement, and a consideration of supplementary technical issues. From the issues identified in table 3.1 to table 3.4 it can be seen that, whilst there are challenges associated with the concept of providing Black Start from DER services, none of these issues are considered prohibitive.

The primary issues can be summarised as:

- anchor generators typically require a minimum load in order for them to safely start – a load bank is likely to be required to provide this (in incremental steps) due to the limited block load capability of the DER
- an anchor generator will be required to provide frequency and voltage control – most will need this capability installed or enabled
- a minimum fault level is required for converter connected generation (e.g. wind farms) to connect – this may not be available on a power island, manufacturers would need to confirm if alternative control settings can be applied for lower fault level operation
- on most sites additional resilient generation may need to be installed for the supply of auxiliary supplies to the generator
- generators utilising a combustion process must control their operation to keep within emissions limits – relaxation of these limits may be required under specified Black Start scenarios.

3.3 Distribution island – technical considerations

The following is an overview of some of the main technical issues associated with establishing a distribution power island.

3.3.1 Low fault level

The primary source of current that will flow during a system fault is a synchronous generator (typically between four and ten times nominal current for a generator terminal fault). Converter connected DER typically contributes only 1.0–1.5 times the nominal current as a constant current source for any fault in the vicinity of the connection point. Thus, a distribution power island will have a much lower fault level than normal, given it will be supplied by a relatively small synchronous generator, and the negligible fault infeed from converter connected DER. This has an impact on:

- **Protection –** The fault current may not be sufficient for the existing protection to detect, or operate, in the speed required.
- **Voltage –** Voltage variations are greater for disturbances in weak grids. This may result in unwanted protection operations or impact on the quality of supply to customers.
- **Converter stability –** The fault level may not be sufficient to allow converter connected DER to connect or result in them disconnecting for voltage disturbances (see section 3.2.2.1).

3.3.2 Low system inertia

Inertia can be seen as the "resistance to change". When a frequency event occurs (e.g a change in the generation/load balance), it prevents the grid frequency suddenly changing and results from synchronous generators having large, heavy, rotating masses on the generator turbine shaft (converter connected DER does not currently contribute to system inertia, although wind turbines have the potential to provide "synthetic inertia").

Low system inertia can therefore result in rapid frequency decline (for load increases/generator losses), with the rate of change of frequency (RoCoF) higher which may result in the frequency going out with acceptable limits and protection operation.

3.3.3 Power island – 33kV voltage control

The voltage on a 33kV network is normally controlled by the automatic tap changing of the grid transformers supplying the 33kV network. For a 33kV power island, these transformers may be out of service and, even if they are in service (i.e. back energised), operation of their tap changers will have little effect on the 33kV voltage (it will only change the 132kV voltage on an isolated 132kV network). It follows that there will be no monitoring or automatic control of the 33kV voltage at the grid substation in a power island.

For a power island, the 33kV voltage will initially be controlled by the excitation of the anchor DER. That is, the generator will seek to maintain a constant voltage (set point) at its terminals. The corresponding 33kV voltage will then be dependent upon the tap position of the generator transformer.

The operational challenge will be to monitor and maintain the 33kV voltage within acceptable limits at all locations on the 33kV network, given the varying generation/demand scenarios, and that voltage transformers for measuring the 33kV voltage will typically only be located at the generation sites. Potential solutions include:

i) selecting the anchor DER voltage set point, and transformer tap position, such that the 33kV voltage remains within limits on all of the network locations for all generation/demand scenarios without any corrective action required (if feasible)

ii) switch in/out reactive compensation if available

iii) change the voltage set point of the anchor DER, or its generator transformer tap position, to change the 33kV voltage

iv) instruct additional DER to generate/absorb MVAr, or have them on automatic voltage control (where more than one DER is controlling the voltage droop [slope], control should be utilised to avoid 'hunting').

3.3.4 High variability of load and generation

A stable power system requires the generation and demand (including losses) to be balanced. For a small power island, there will not be the same diversity of demand as a large power system, and the loss of a single feeder can result in a large load change and a significant generation and demand imbalance. In addition, there will not be the same amount of dispatchable generation which may be called upon if required.

As the share of intermittent generation on the power island is increased, this introduces another variable in keeping the generation and load balanced. In particular, solar generation may be difficult to integrate given that its output is very unpredictable and variable, being dependent on cloud cover.

3.3.5 Oscillations

Oscillations of power, voltage and frequency can occur on a small distribution network where power flows, voltage magnitudes and frequency are more closely coupled (due to the relatively small impedances of the circuits in the network). In addition, poor co-ordination between different frequency controllers and power sharing between multiple DERs could result in small frequency perturbations, which could lead to large frequency oscillations. Fast voltage and frequency responses may be required to damp such oscillations and maintain stable operation of the power island system.

3.3.6 Issues register

Table 3.5 shows the technical issues that have been identified in relation to distribution power island operation.

Table 3.5

Issues register – distribution island technical considerations

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DIO	DIO 1	A distribution power island will have a low fault level relative to normal operation.	Existing protection may not be able to detect faults/operate quickly enough. Voltage disturbances will be greater causing unwanted protection operations. Converter connected generation may not be able to connect or remain stable.	Carry out a protection study and provide alternative settings/protections for a Black Start scenario. Converter manufacturers to determine if the coverter can be 're-tuned' for the available fault level, and if settings can be changed automatically for a Black Start. Prioritise the energisation of available	
DIO	DIO 2	System oscillations.	Oscillations between power, voltage and frequency can occur on a closely coupled distribution power island.	Carry out the required transient/dynamic studies to identify any issues. Install suitable monitoring equipment during trials. Design mitigation measures e.g fast f response if available from DER.	
DIO	DIO 5	Low system inertia.	A generation/load imbalance will cause larger frequency changes due to low inertia.This will result in a more severe test of the generator's governors than with intact system conditions.	Where practical a control scheme should be employed to minimise the generation/load imbalance of the power island which the generator 'sees'. If available, additional anchor DER could be brought on line initially to increase inertia.	
DIO	DIO 6	High variability of load and generation (particularly solar).	It may be hard to maintain a stable frequency in a power island where the demand and intermittent generation resources are much more variable on a power island.	The capacity of intermittent generation connected (particularly solar) will have to be limited to take into account the unpredicatability of the resource. Adequate capacity margin will be required on the synchronous generation.	
DIO	DIO 7	Power island 33kV voltage control	When operating a 33kV power island there will be no direct way of monitoring or controlling the 33kV voltage.	A microgrid controller could be utilised to monitor the 33kV voltage and take corrective actions e.g. switch in/out reactive compensation. Alternatively DER could be used to monitor and control the 33kV voltage.	

3.4 Distribution island – operational considerations and automation

The technical and operational challenges associated with establishing, growing, maintaining and restoring a distribution (33kV) power island are discussed. Given these challenges, and the limited human resources which may be available at the time of a Black Start (a DNO control room may have as few as two engineers on shift during the night), it is likely that some level of automation will be required for the process to be viable.

The application of automation is considered in the form of a microgrid control system. Such systems are currently used for co-ordinating and controlling the power balance, demand side response and economic dispatch of resources in typically a single customer site and at lower voltages than 33kV. The control architecture of a microgrid system can either be decentralised (each DER self-regulates based on local measurements), centralised (a central controller makes all the decisions), or hierarchical (a combination of centralised and decentralised). There can also be 'tertiary control' where the operation of multiple microgrids interacting with each other is co-ordinated.

In this report, the application of a microgrid control system to a wider DNO network is discussed. The control architecture to achieve this is out of the scope of this document and will be considered by the Organisational Systems and Telecoms workstream.

3.4.1 Power island initiation

In order to establish a distribution power island, a number of initial actions will be required, including:

- sending out Black Start signals to DER.

The DER will need to know the difference between a normal grid outage and a Black Start situation. Based on this, they may need to make changes to their plant, e.g. change generator control modes.

- Open/close DNO circuit breakers/confirm the status of circuit breakers or circuits.

Demarcation of the power island will be required in terms of the substation and feeders to be included and the initial state of the circuit breakers. This may include bringing on some network initially with the anchor generator depending on the energisation strategy employed.

- Change network protection settings/switch protections out of service.

Due to the low fault level, it is likely that alternative protection settings will be required at strategic locations, and some protections switched out of service to avoid operating in a more dynamic system (e.g. under frequency load shed panels).

3.4.1.1 Microgrid controller application

On receipt of a single Black Start signal, a microgrid controller could initiate all the control signals required to set up the power island and confirm to the relevant control person(s) when all actions were complete, or highlight any issues that would inhibit restoration.

3.4.2 Anchor generation start-up

The next stage is to start up the anchor generator. This may be started by power station personnel (on 24/7 manned sites or by personnel sent to site), or via signalling from remote control rooms. Synchronous generators typically prefer, or require, a minimum load to be available within the first few minutes of starting (this can be up to approximately 50 per cent of their rating). This is dependent upon the design and limitations of their prime mover. Further detailed technical discussions with DER will confirm the minimum technically acceptable load.

For distribution power islands, providing the initial minimum generator demand would be an issue given that the load on any particular feeder will not be known accurately and that the minimum load required is likely to exceed the block load capability of the generator (see section 3.4.3).

One potential solution is to install a load bank (or utilise a battery if it is available) which would provide the necessary load for the generator to start, and also in incremental steps within the block load capability of the generator.

3.4.2.1 Microgrid controller application

The microgrid controller could send the required 'generator ready to start' signals to the anchor DER, whether to start an automatic or manual process. As the generator is starting, the microgrid controller could provide the interface between the generator and load bank to ensure that the required load is provided at the right time.

3.4.3 Block load capability

The next stage in the process is for the anchor generator to pick up some customer demand. It is likely that the minimum demand that can be connected at any one time will be that of a primary (33/11kV) substation to ensure that the number of switching operations, and associated time, is not excessive. This would result in demand blocks of several MWs up to ~20 MW.

A generator's ability to connect to demand is known as its block load capability. In the Grid Code, this is defined as 'active power step (MW) a generator can instantaneously supply without causing it to trip or go outside 47.5 Hz–52 Hz (or otherwise agreed)'. The block loading capability is dependent upon four main factors:

i) the size of load applied (MW)
ii) the inertia of the generator (for lower inertia the frequency will fall faster when the load is applied)
iii) the type of generator (the differing governor responses can be approximately split into four types of prime mover: diesel, steam, gas turbine and hydro)
iv) boiler feeder characteristics (steam).

Given the low inertia of a DER, it is likely that the demand associated with a primary substation will be out with its block load capability. This may be as low as 5 per cent –10 per cent of its rating and will be studied within the forthcoming design phase of this project.

3.4.3.1 Microgrid controller application

A microgrid controller could enhance the block load capability of a DER by sending a signal to switch out the anticipated load at the DER load bank, at the same time as energising a primary substation. As a result, the anchor generator would only 'see' the difference in MW which may be within its block load capability. If it is not, the microgrid could monitor the change in the output of the anchor DER, and operate the load bank further to make the output MW change of the anchor generator within its block load capability.

3.4.4 Maintaining a stable power island – frequency

With the anchor generator connected to demand, the challenge is now to keep the frequency within acceptable limits, given the changing nature of demand and of generation (if intermittent DER is included), and also following system disturbances (e.g a fault outage of a load feeder). At least one synchronous generator will be required to provide frequency control, but its MW capability and inertia may be insufficient to maintain the system frequency resulting in the generator tripping and collapse of the power island.

3.4.4.1 Microgrid controller application

A microgrid controller could be used to 'preserve' the power island and 'protect' the anchor generator. For example, if the load increases, frequency starts to drop, and the anchor generator exceeds a set level of output (e.g 90 per cent of its rating), then to avoid collapse of the power island, the microgrid could take action to 'protect' the anchor generator. For example, it could ensure any load banks are fully switched out, signal additional DER to provide more MWs if available, and as a last resort shed the required amount of load.

If the frequency goes high, and/or the anchor generator is in danger of going below its minimum stable demand, the microgrid controller can take action such as switching in the load bank, connecting additional demand or reducing the output from any additional DER.

3.4.5 Maintaining a stable power island – voltage

For a 33kV power island, there will be no automatic way of monitoring or directly controlling the 33kV voltage (see section 3.3.3).

The operational challenge will be to monitor and maintain the 33kV voltage within acceptable limits, given the varying generation and demand scenarios.

3.4.5.1 Microgrid controller application

The microgrid controller could be used to monitor the 33kV voltage at strategic locations (ideally where there are existing voltage transformers) and take corrective action if the voltage goes beyond pre-set limits. For example, the microgrid controller could send a signal to the anchor DER to change their voltage set point, signal the anchor DER to change their generator transformer tap position, switch in/out reactive compensation, switch in/out demand/load banks or send a signal to additional DER to change their operating power factor.

3.4.6 Synchronising the distribution power island to the wider network

The distribution power island would be designed to be synchronised to the wider network once the main interconnected transmission network (MITS) has been restored. The synchronising point could be either at a distribution or transmission voltage level using check synchronising relays.

The conditions will have to be defined that determine when to terminate the Black Start. That is, the power island may have been resynchronised, but the wider network may still be a weak one, such that some Black Start functionality is still required on the power island. At a suitable time, it will be required to restore all controls and protection settings etc. back to normal operation.

3.4.6.1 Microgrid controller application

The microgrid controller could be used to signal the DER when the power system has returned to normal and the Black Start is officially over. At an appropriate time, the microgrid controller could simultaneously reset all DER, network settings, and controls.

3.4.7 Conclusions for the distribution island operational considerations and automation

Throughout the various stages of establishing, growing, maintaining and reconnecting a power island, there will be a balance between automation and human intervention required to make the process viable in terms of timescales and available resources, but also in operating a safe and secure network.

Table 3.6 shows the technical issues that have been identified in relation to distribution power island operational challenges and automation.

Table 3.6

Issues register – distribution island – operational considerations and automation

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DIO	DIO 3	Lack of human resources (DNO control engineers and DER personnel) to establish and maintain distribution power islands and associated restoration times with only manual intervention.	Design a level of automation into the Black Start from DER process that makes it viable with existing human resources but also results in a safe and manageable system.	Identify the required functionality and architecture for microgrid controllers to provide the required level of automation.	
DIO	DIO 4	Block load capability of DER in a power island.	The block load capability of DER (due to low system inertia) may not be sufficient to pick up the demand of a primary substation. Additional 11kV switching may be required to reduce the demand block size which may not be viable operationally and completed within exceptable timescales.	Options for reducing the net block loading a DER 'sees' by using load banks or batteries (controlled by a microgrid) should be investigated.	

3.5 Distribution island – restoration strategies

The initial distribution power island restoration strategies are considered, along with the wider restoration strategies that may be employed.

3.5.1 Initial distribution power island restoration

There are a number of considerations when deciding on the initial energisation strategies including:

i) If back energisation of a 132/33kV transformer is required, it would be best to do this initially in a way that minimises the inrush current as this is likely to exceed the capability of the 33kV anchor generator. This can be done by energising the transformer with a voltage less than 33kV (achieved by tapping the generator transformer or adjusting the generator terminal voltage). A reduction to 0.95 p.u. volts, at the appropriate location, may result in a significant enough reduction to the inrush current (transient studies will be carried out in the design stage to confirm). Alternatively, the excitation of the anchor DER can be switched on and increased with the transformer and associated network in service, resulting in the voltage being ramped up and negligible inrush current. Both these scenarios require that the 132/33kV transformer is energised before any customers are connected to avoid the impact of the non-standard voltage.

ii) A primary (33/11kV) transformer may be required to be energised with its 11kV load connected, as opposed to the transformer energised with its 11kV circuit breaker open, and then subsequently closed to connect the load. This is because, prior to a blackout, the primary transformer may have been heavily loaded and the tap changer will have tapped to a position to keep the 11kV voltage within acceptable limits. If the transformer is then energised without the load, studies have shown that the open circuit 11kV voltage may be up to 10 per cent above nominal. There will also be no local LV supplies available to power the tap change motor and reduce the voltage. The statutory upper limit is 6 per cent, with the switchgear typically having a 10 per cent insulation limit.

iii) If there is a wind farm on the power island required for restoration services, and no auxiliary power has been installed to maintain heating to the turbines, then the 33kV supply should be energised as a priority so that the turbines have their auxiliary power for gear-box oil heating (whether MWs are required from the wind farm initially or not). This will ensure that the wind farm will be available when required (ideally the supply should be restored within ~six hours of a Black Start to minimise the risk of unavailability).

iv) Typically a primary substation is supplied by two 33/11kV transformers with an 11kV bus section circuit breaker. To reduce the load pick-up when a primary transformer is energised, if the 11kV bus section circuit breaker is opened, the load will approximately halve with most primaries having 11kV circuits connected either side of the bus section with open points. (Each primary would need to be assessed to ensure that it did not have 11kV closed circuits connecting across the bus section.)

Based on the above and other factors to be determined in the design stage of the project, a restoration plan should be developed for each 33kV power island network in order that the desired network and/or customers can be restored in a timely manner.

3.5.2 Wider restoration strategies

Once a 33kV DER power island has been established, there are a number of alternative strategies. A number of these are described below based on the Chapelcross case study. The schematic is shown in figure 3.1.

i) Do nothing else – maintain a 33kV power island (with the maximum stable load reconnected), and wait until the associated grid transformers (132/33kV or 275/33kV) have been energised from the MITS and synchronise the power island (shown as option 1 in figure 3.1).

ii) Expand the 33kV power island into an adjacent 33kV grid network, via 33kV interconnecting circuits, to utilise the power island to connect additional demand and/or non-synchronous generation (shown as option 2 in figure 3.1).

iii) Synchronise the 33kV power island with an adjacent 33kV power island, through 33kV interconnecting circuits, to establish a larger 33kV power island and combine all DER resources (shown as option 3 in figure 3.1).

iv) Expand from the 33kV power island to the associated 132kV grid substation. From there it may then be possible to:

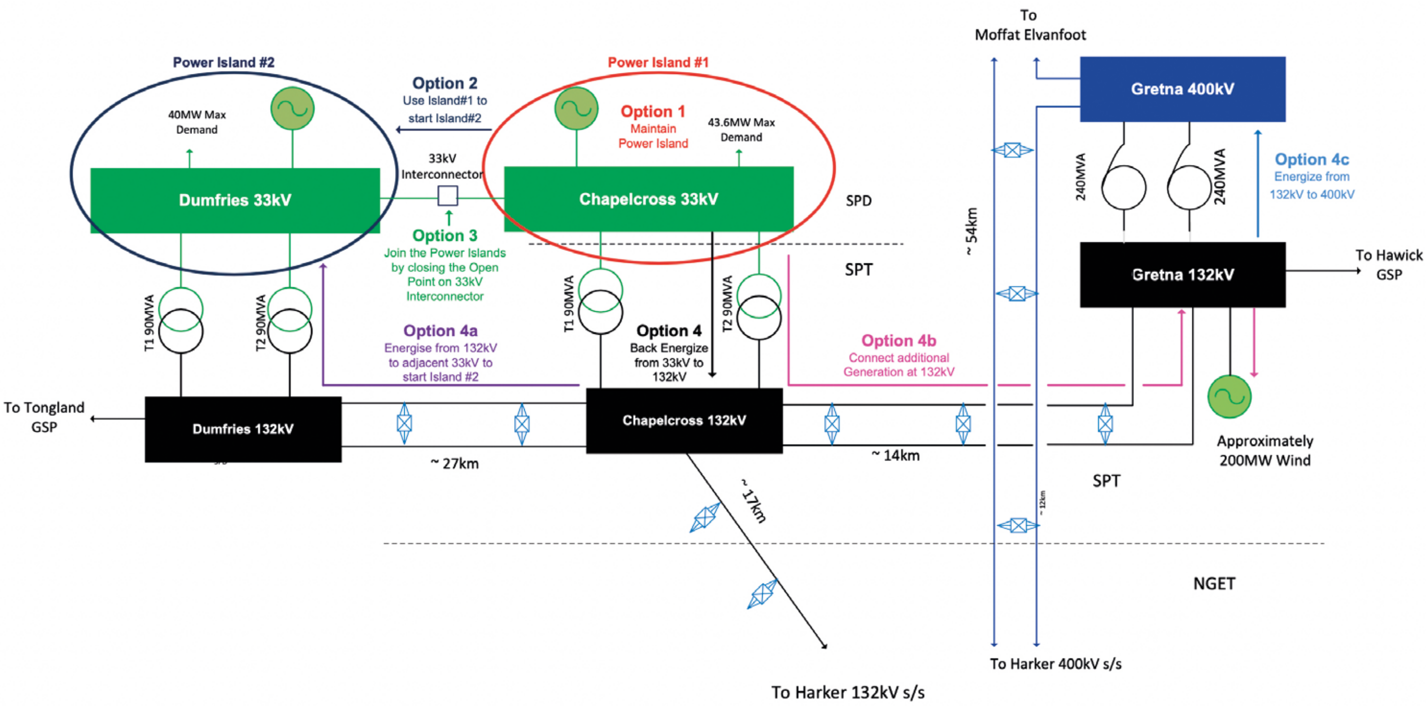
   1) energise a 132kV circuit and an adjacent 132/33kV grid substation from the ‘top down’ to establish a second 33kV power island and connect more demand and/or DER (shown as option 4a in figure 3.1).

   2) energise a 132kV circuit to connect additional generation directly connected to the 132kV network. This would expand the power island to effectively become a virtual power station (shown as option 4b in figure 3.2).

   3) expand from the 132kV network to energise the 275kV and/or 400kV transmission network (shown as option 5 in figure 3.1).

In the design stage of the project, the technical requirements associated with each restoration strategy will be examined, and a cost-benefit analysis undertaken. It is envisaged that there will be a tipping point in the restoration strategies, above which expansion from DER power islands will not be viable.

Figure 3.1
Wider restoration strategies schematic



3.6 Distribution network – earthing and protection

A study[1] has been undertaken to identify potential earthing and protection issues on the SPD and SPT networks when the source generator is a 33kV DER. The study has been based on the Chapelcross 132/33kV GSP case study, and the surrounding transmission and distribution networks.

3.6.1 Earthing

This section identifies the standards and legislation which may be applicable under Black Start conditions with regard to earthing. It also provides a summary of the typical DNO 33kV earthing schemes and discusses the issues, along with the mitigation options, associated with earthing the 33kV network when operating as a power island.

3.6.1.1 Applicable standards and legislation

With respect to earthing, there are a number of relevant standards and legislation which may be applicable under Black Start conditions. The relevant documents, and sections, are listed below, along with a sample of the guidance given.

- Electricity Safety, Quality Continuity Regulations (ESQCR) Regulation 8 (general requirements for connection with earth) states:

  "(1) A generator or distributor shall ensure that, so far as is reasonably practicable, his network does not become disconnected from earth in the event of any foreseeable current due to a fault.

  (2) A generator or distributor shall, in respect of any high voltage network which he owns or operates, ensure that –

  (a) the network is connected with earth at, or as near as is reasonably practicable to, the source of voltage but where there is more than one source of voltage in that network, the connection with earth need only be made at one such point;

  (b) the earth electrodes are designed, installed and used in such a manner so as to prevent danger occurring in any low voltage network as a result of any fault in the high voltage network; and

  (c) where the network is connected with earth through a continuously rated arc suppression coil, an automatic warning is given to the generator or distributor (as the case may be) of any fault which causes the arc suppression coil to operate."

[1] ARCADIS Black Start from distributed energy resources. Protection and Earthing Study. June 2019.

- Distribution Code. The Distribution Planning and Connection Code section of the Distribution Code (DPC4.42 earthing) states:
  "(a) The arrangements for connecting the DNO's Distribution System with earth shall be designed to comply with the requirements of the ESQCR and relevant European and British Standards."
- Requirements for Generators (RfG) Article 15 (General requirements for type C power-generating modules) states:
  "(f) earthing arrangement of the neutral-point at the network side of step-up transformers shall comply with the specifications of the relevant system operator."
- EREC G99 section 5 (legal aspects) states:
  "All Generators have to comply with the appropriate parts of the ESQCR."
- EREC G99 section 8 (earthing) states:
  "The earthing arrangements of the Power Generating Module shall satisfy the requirements of DPC4 of the Distribution Code."

3.6.1.2 Typical DNO 33kV earthing schemes

Table 3.7 summarises the typical 33kV earthing schemes employed by each DNO using information gathered from their respective LTDSs. An overview of the different system earthing types identified is given in Appendix G – overview of typical DNO earthing arrangements.

Table 3.7

Typical DNO 33kV earthing schemes

DNO	33kV earthing scheme
Scottish Power Distribution – SPEN	Auxiliary 33/0.4kV transformer and liquid earthing resistor connected closely to the GSP transformer's secondary bushings. This limits the earth fault current to the full load rating of the transformer.
Scottish Power Manweb – SPEN	
Scottish Hydro Electric Power Distribution – SSEN	Direct earthing – the only impedance between the transformer lower voltage winding star point (neutral) and earth consists of the earthing conductor and the resistance between the earth mat and earth.
Southern Electricity Power Distribution – SSEN	Resistance earthing – use is made of an earthing resistor between the transformer lower voltage winding star point (neutral) and earth to limit the fault current.
	Earthing transformers – where lower voltage winding is delta connected, a neutral point is derived artificially by inclusion of an earthing transformer. This neutral point is then appropriately earthed.
Northern Powergrid (Northeast)	Star point of 33kV system is earthed at its source only on the lower voltage side of the grid transformers. Where the lower voltage side is delta wound, an earthing transformer is used to earth the lower voltage winding. The characteristics of the earthing transformer ensure that the earth fault current does not exceed the full load current of the associated transformer.
Northern Powergrid (Yorkshire)	
Electricity North West	Impedance earthed – typical neutral earth resistor will limit the earth fault current to 1000 A per transformer, i.e. giving a maximum earth fault level of 3kA.
WPD (East Midlands)	All 132/33kV transformers have their lower voltage winding earthed via an earthing transformer. The 33kV windings are either earthed through a resistor or reactor or have high impedance earthing transformers.
WPD (West Midlands)	All 132/33kV transformers have their lower voltage winding earthed via an earthing transformer.
	Resistor or reactor earthing to limit earth fault currents to below 3000 A.
	All 132/33kV transformers have their lower voltage winding earthed via an earthing transformer.
WPD (South West)	The 33kV windings are either earthed through a resistor or reactor or have high impedance earthing transformers.
	WPD policy on 33kV protection requires that earth fault levels are restricted to 3000 A.
	Arc suppression (Petersen coils) are in use on parts of the network in Cornwall.
WPD (South Wales)	Most 132/33kV transformers have their lower voltage winding earthed via an earthing transformer and earth resistor.
UK Power Networks (Eastern)	The 33kV system uses impedance earthing where the source neutral is connected to earth via a neutral earthing resistor or reactor.
UK Power Networks (South Eastern)	
UK Power Networks (London)	The 33kV system uses direct earthing or impedance earthing where the source neutral is connected to earth via a neutral earthing resistor or reactor.

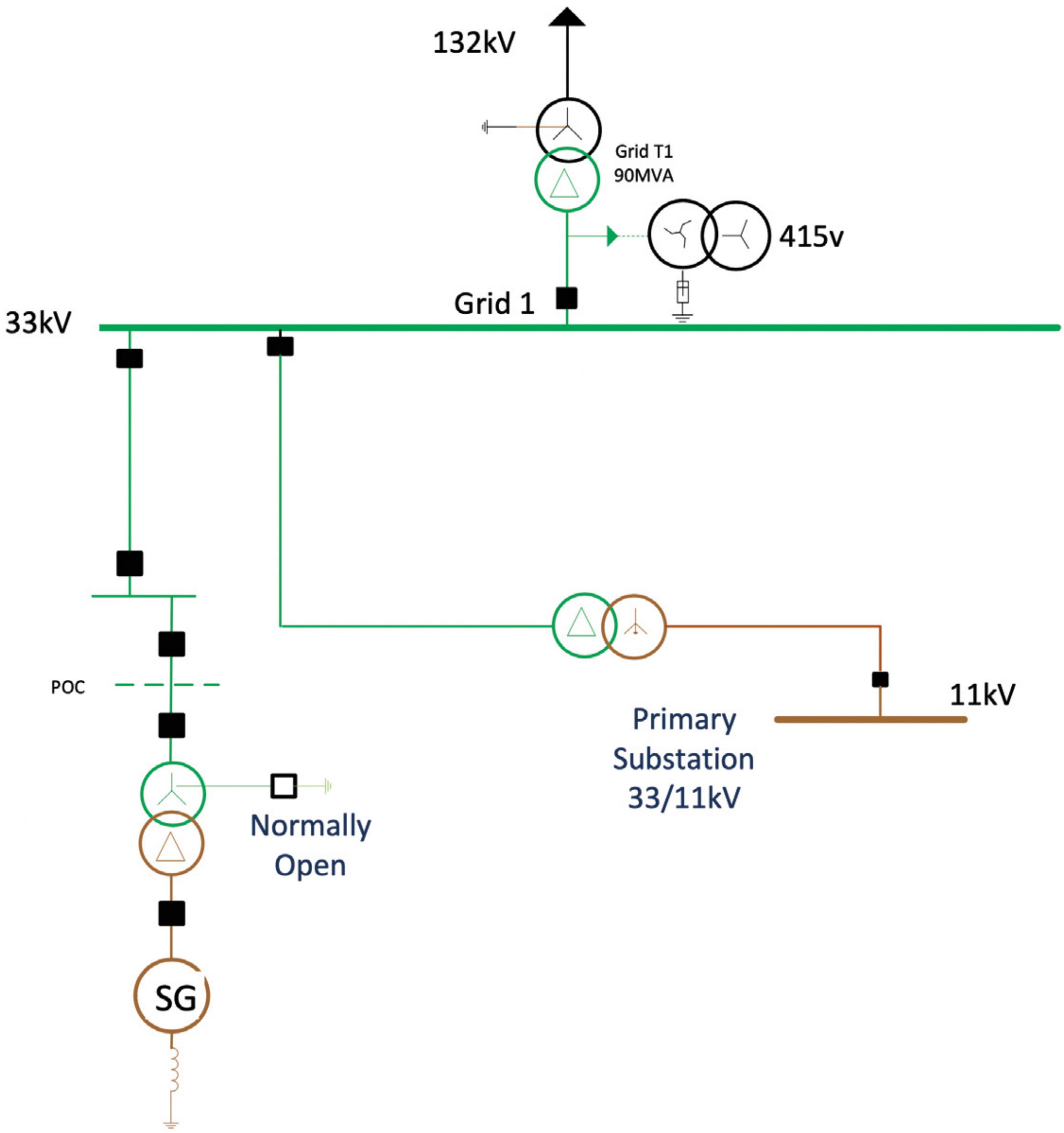
3.6.1.3 Power island 33kV earthing requirements, issues and mitigation

SPD and SPM 33kV Earthing Configuration

SPD and SPM utilise the same resistance earthed scheme for all of their 33kV networks. As shown in figure 3.2 (taken from the Chapelcross case study schematic), an earthing transformer (zigzag-star) is connected between the grid transformer and the transformer 33kV circuit breaker (Grid 1). The neutral point of the 33kV zigzag transformer is earthed through a resistor which limits the maximum earth fault current through the transformer to its rating (in this case 90MVA). The same earthing arrangement would be used for a 275/33kV substation.

Figure 3.2

SPD/SPM 33kV earthing configuration



There are no other 33kV earth connections on the 33kV network. All primary substation (33/11kV) transformers have a delta HV winding, and all generators connecting at 33kV are required to ensure that their HV transformer winding is unearthed. To achieve this, the majority of generator transformers have a delta 33kV winding, however a star winding may be used with a circuit breaker in the neutral earth connection which is normally open (as shown in the Chapelcross case study example in figure 3.2).

When operating as a 33kV power island, the grid transformer circuit breakers will be open (Grid 1 in figure 3.2). The resultant 33kV network will be unearthed. This does not comply with the ESQCR Regulation 8 which states that, “the network is connected with earth at, or as near as is reasonably practicable to, the source of voltage”.

N.B. In this example, the synchronous generator is located approximately 25km from the grid substation, connected by a 33kV underground cable circuit.

Power island 33kV network earthing options

Table 3.8 summarises the main alternatives for earthing the 33kV network when operating as a power island, supplied from an anchor DER. The issues associated with each option are given and mitigation measures are noted (where applicable). A rating has been given to the feasibility of each issue being overcome and is used to determine the most appropriate earthing solution.

Table 3.8

Power island 33kV network earthing options

Option	Description	Issues	Mitigation	Rating
1	Use the existing earthing transformers on the grid transformers at the GSP.	The system earth would be remote from the source of voltage. The ESQCR states that it should be ensured that the network is connected with earth at, or as near as reasonably practicable to, the source of voltage.		
		The grid transformer will need to be isolated on the H.V side (to avoid energising a transmission circuit also). Not all grid Txs will have a circuit breaker at the H.V. If only an isolator it may not be able to be opened remotely. Even if opened, it is not rated to be closed later to energise a transmission circuit.	A circuit breaker could be installed on the H.V side of the transformer (expensive and may not be practical).	
		Requires grid transformer to be connected when the 33kV network is first energised. The anchor generator will likely not have the capability to magnitise the transformer.	Transformer could be energised as generator voltage increased to give a 'soft start'. However, this would require any load connections to be isolated initially from the 33kV circuit between the anchor DER and grid transformer.	
		If the generator feeder 33kV CB opens at the GSP end (for a fault on the generator circuit) the generator will be left feeding an unearthed 33kV circuit.	NVD protection could be installed at the generator (5 lmv V.T required which may require a new 33kV circuit breaker) or intertripping could be installed from the GSP end to the generator.	
		A fault on the grid transformer would require the generator to be disconnected and the 33 kV island system de-energised.		

Table 3.8 continued
Power island 33kV network earthing options

2	Move the earthing transformers connection to the GSP 33kV busbars.	The system earth would be remote from the source of voltage. The ESQCR states that it should be ensured that the network is connected with earth at, or as near as reasonably practicable to, the source of voltage.		
		The grid transformers would not be earthed on their 33kV connections meaning they could not be safely energised if their 33kV circuit breakers were open.		
		Requires the addition of two 33 kV breakers to connect the earthing transformers.		
		If the generator feeder 33kV CB opens at the GSP end (for a fault on the generator circuit) the generator will be left feeding an unearthed 33kV circuit.	NVD protection could be installed at the generator (5 lmv V.T required which may require a new 33kV circuit breaker) or intertripping could be installed from the GSP end to the generator.	
3	Install a new earthing transformer at the anchor generator 33kV substation,	Requirement for new earthing transformer and possibly switchgear (only switched in service in a Black Start scenario). This may not be easy to install retrospectively at an existing substation.		
		Earthing at GSP would have to be assessed, i.e. ROEP, step and touch potentials and earth mat design.		
		If the generator earthing transformer was connected in parallel with the two GSP earthing transformers the total earth fault current may exceed the earth mat design at the GSP.	Ensure that the power island restoration plan does not result in all three earthing transformers being in service simultaneously.	
4	The generator transformer 33 kV winding is connected in star with a switchable connection to earth via a resistor	Retrospectively this would be expensive to install but for new connections the additional cost may be negligible.	For new connections of synchronous generators at 33kV, the DNO requirement to have a switched H.V earth connection on their transformer could be included (instead of the current unearthed H.V winding requirement).	
		Earthing at GSP would have to be assessed, i.e. ROEP, step and touch potentials and earth mat design.		
		If the generator earthing transformer was connected in parallel with the two GSP earthing transformers the total earth fault current may exceed the earth mat design at the GSP.	Ensure that the power island restoration plan does not result in all three earthing transformers being in service simultaneously.	
		This configuration is rarer than a delta 33 kV winding so would require replacement equipment and a change to DNO earthing policies. Where this is an existing configuration it may be utilised without the need for changing equipment.		

Anchor generator earthing transformer design

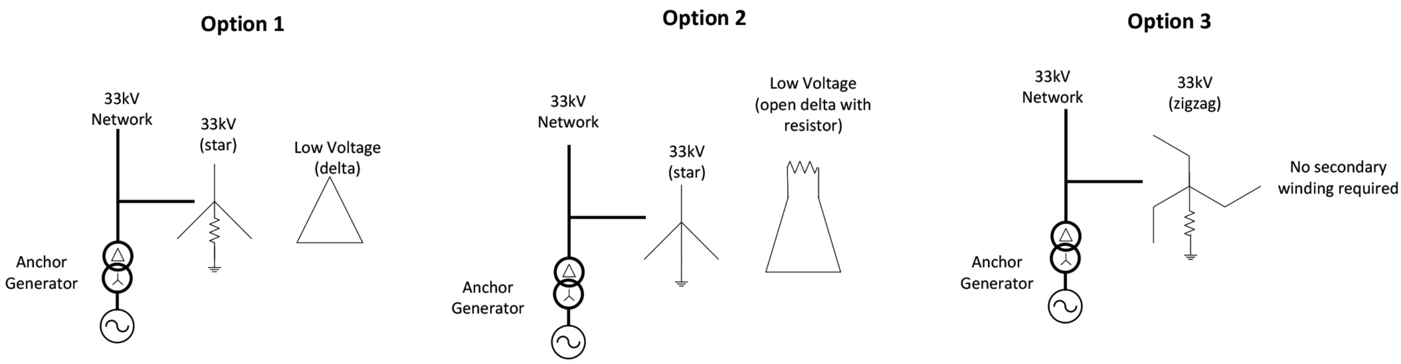
It can be seen in table 3.8 that the most viable option, for existing anchor generator connections, is to install an earthing transformer at the generation site. Figure 3.3 shows the three options for the design of the earthing transformer that have been identified. These will provide an earth return path where the generator transformer HV winding is a delta configuration, allowing fault current to flow and the protection to detect this and operate. The earthing transformer designs will also be suitable if the transformer HV winding is an unearthed star configuration, although if so, it would be simpler to have a switched neutral earth with a resistor.

For each option, the value of the resistor would be calculated to give the required earth fault current. Ideally, this should be matched to the existing earth fault infeed from a single grid transformer such that there will be no issues with the existing 33kV earth fault protection. The voltage of the secondary winding transformer would be optimised based on the power that was required to circulate.

The anchor generator earthing transformer could operate in parallel with a grid earthing transformer if one of the grid transformers was back energised from the 33kV power island. The earthing at the grid substation would have to be assessed to ensure that the rise of earth potential (ROEP), step and touch potentials, and earth mat design are still adequate given a local and a remote earthing transformer. More than one grid substation earthing transformer, and the generator earthing transformer, should not be operated in parallel as this will result in the earth fault level being at least ~150 per cent of the maximum value in normal operation.

Figure 3.3

Earthing transformer options



3.6.1.4 Earthing issues register and conclusions

The network earthing issues associated with Black Start from DER are summarised in the issue register shown in table 3.9.

Table 3.9
Network earthing issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
Earthing	E1	The 33kV network will be unearthed if the grid transformer L.V circuit breakers are open. In addition, the location of the earthing transformers does not comply with the ESQCR when the network is energised from a DER remote to the grid substation.	An alternative means of earthing the 33kV network will be required if a 33kV power island is to be established.	An earthing transformer could be installed at the anchor generator 33kV substation. The DNO policy could be changed such that new anchor generators provide a switchable earthed 33kV transformer winding.	
Earthing	E2	The Rise of Earth Potential (RoEP) may increase at the grid substation with an earthing transformer fault infeed from a remote generator site.	Safety is required to be maintained at the grid substation.	An earthing study may be required at the grid substation to confirm if the existing earth mat is adequate.	
Earthing	E3	The33kV generator earthing transformer should not be operated in parallel with more than one grid earthing transformer.	It is unlikely that expansion of a 33kV power island would involve more than one grid transformer connected to that network.	Restoration plans will have to ensure only one grid transformer is switched in service with an anchor generator with an earthing transformer.	

The following conclusions can be drawn from analysing the earthing options in a 33kV power island.

- In a Black Start scenario, a 33kV power island will require a new method of earthing (the existing earthing transformers are connected to the grid transformers and will be disconnected from the system).
- The Electricity Safety, Quality and Continuity Regulations (ESQCR) require a network to be connected to earth, “at or as near as is reasonably practicable to the source of voltage”.
- A new 33kV earthing transformer will be required at most anchor generation installations.
- An alternative would be for all future potential anchor generators to have a switchable earth connection on their generator transformer 33kV winding.

3.6.2 Fault levels

Within an electrical system, fault level is defined as the maximum current that would flow during a short circuit fault. It is a measure of the electrical strength of a system and, whilst fault levels must be limited for safety reasons, a minimum threshold is required to ensure protection systems operate correctly.

Before the operation of the existing protections can be assessed, the relevant network fault levels must be calculated when the only fault infeed source is the 33kV connected anchor DER. The following summarises the results obtained for the Chapelcross GSP case study network which has a 45MW synchronous generator as the anchor DER.

3.6.2.1 Chapelcross 33kV fault levels

Table 3.10 shows that the 33kV three phase fault levels, when supplied from a single DER, reduce to as low as 14 per cent of the value when supplied from a single 132/33kV grid transformer. This is recorded at the Chapelcross grid 33kV busbar.

There are no issues with the reduction of the 33kV earth fault levels, as these can be designed to be equivalent to the existing earth fault level from a single grid transformer by the design of the earthing transformer at the anchor DER site.

Table 3.10
LLL fault levels for power island network compared with single grid transformer supply

ID	Location	DIgSILENT node name	LLL Ib (kA) LTDS	LLL Ib (kA) power island	LLL Ib (%) power island
F1	Generator Transformer 33kV	STCR3-	9.18	2.56	28%
F2	Chapelcross GSP 33kV	CHAP3A1	15.75	2.16	14%
F3	Annan T1 33kV	ANANT1	8.40	1.95	23%
F7	Moffat T1 33kV	MOFTT1	0.81	0.67	83%
F11	Langholm T1 33kV	LAHOT1	1.80	0.93	52%
F13	Ewe Hill WF POC 33kV	EWHC3-	4.16	1.45	35%
F14	Minsca WF POC 33kV	MINS3-	8.93	1.78	20%

3.6.2.2 Chapelcross 11kV and LV (415V) fault levels
Figure 3.4 and figure 3.5 show respectively how the Chapelcross 11kV and 415V fault levels vary relative to the 33kV three phase fault level at the grid substation.

Figure 3.4
11kV LLL fault levels with varying 33kV GSP LLL fault levels

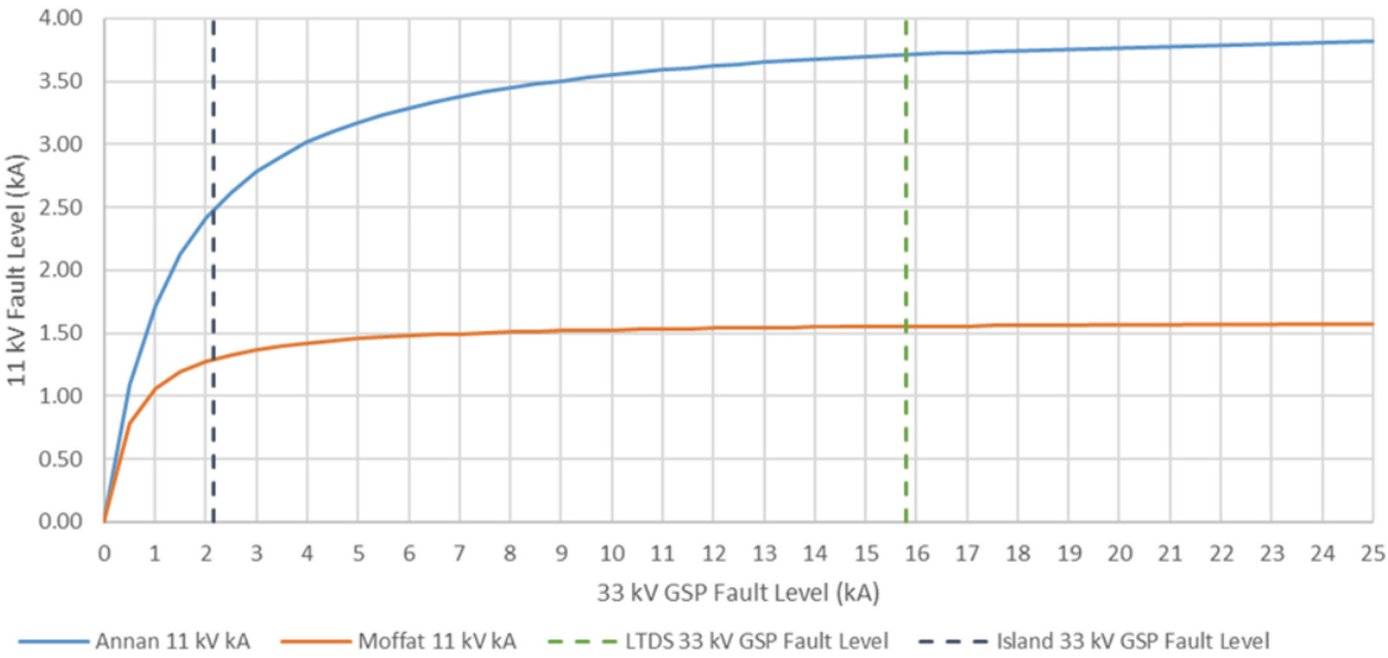


Figure 3.4 shows that for a 33kV fault level of ~2kA (provided by the anchor generator), the fault levels at 11kV locations will be around 60 per cent–85 per cent of the normal values.

Figure 3.5
415V LLL fault levels with varying 33kV GSP LLL fault levels

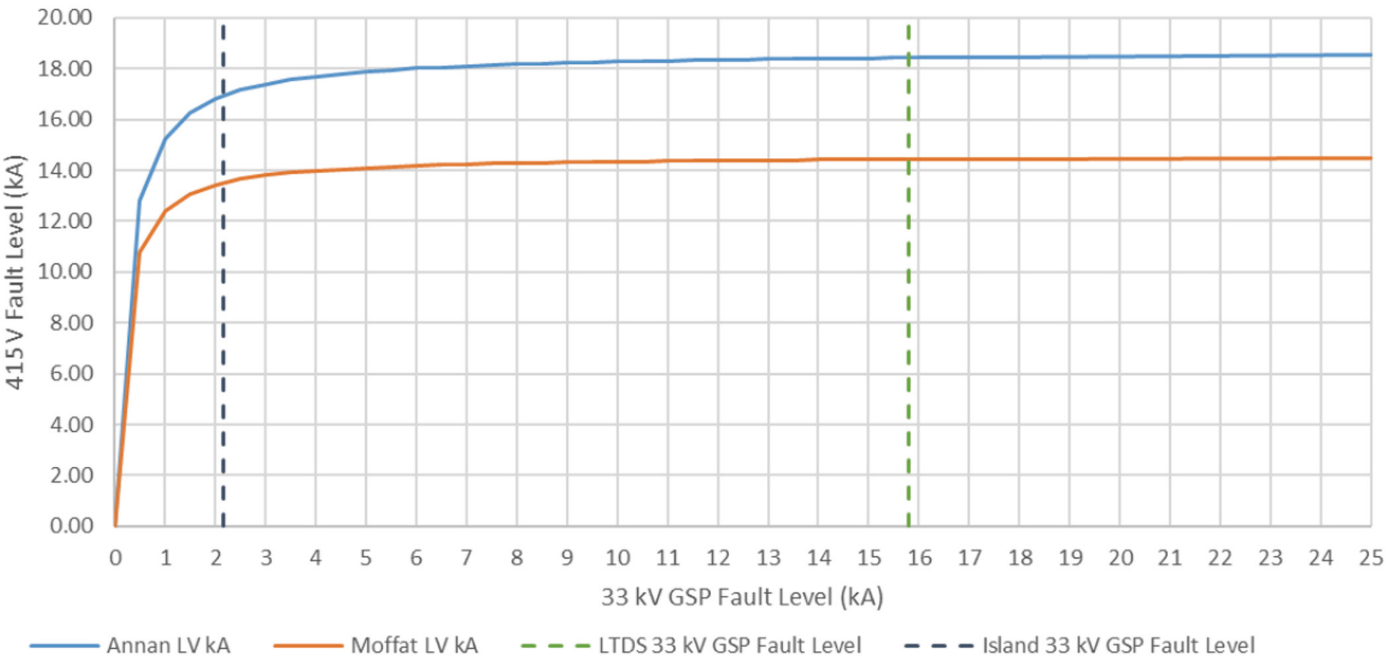


Figure 3.5 shows that for a 33kV fault level of ~2kA (provided by the anchor generator), the fault levels at 415V locations will be close to their normal values. Moreover, it can be seen that for 33kV fault levels greater than ~540A (30MVA), the corresponding LV fault level will be ~65 per cent of its normal value or more. This means that a minimum fault level of ~30MVA (at a GSP 33kV busbar) is required to ensure correct downstream LV protection operation.

3.6.2.3 Generator terminal fault voltage

The calculated initial system voltages, at the anchor generator 11kV terminals and 33kV substation, following a bolted three phase fault at various locations, are shown in table 3.11. This table shows that the initial voltage dip at the generator terminals will be significant for 33kV and 132kV faults. The generator voltage and frequency settings will need to take account of this.

Table 3.11
Calculated LLL fault voltages for power island network with anchor DER only

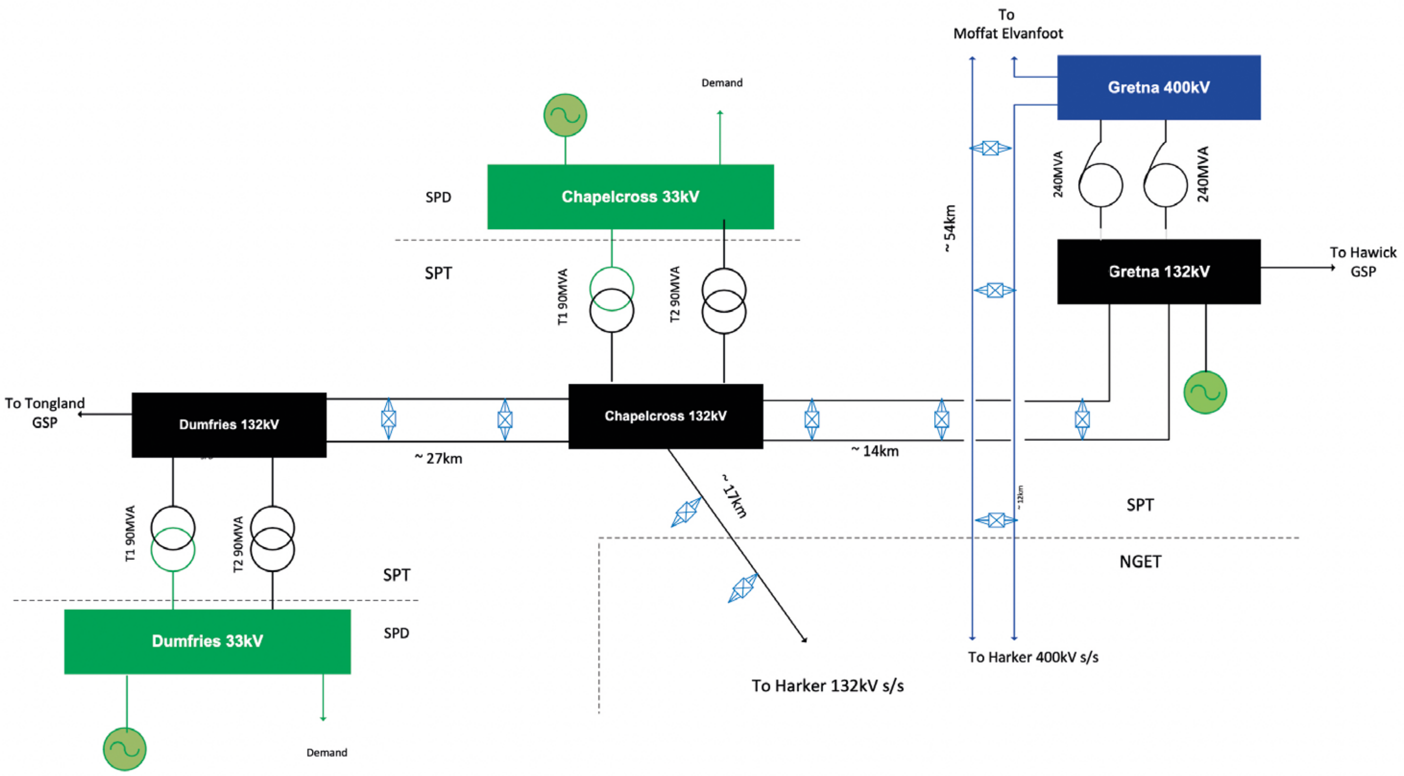
ID	Location	DIgSILENT node name	Fault at CHAP1-132kV V (pu)	Fault at CHAP3A1 33kV V (pu)	Fault at ANANT1 33kV V (pu)	Fault at ANAN5-11kV V (pu)	Fault at ANNAN_LV 415V V (pu)
F1	Generator Transformer 33kV	STCR3-	0.42	0.20	0.31	0.74	0.97
-	Generator 11kV Terminals	STCR5-	0.72	0.65	0.69	0.88	0.97

3.6.2.4 Wider fault level calculations

The wider network associated with Chapelcross GSP is shown in figure 3.6. The fault levels on the wider transmission and distribution networks, energised from Chapelcross GSP with a single anchor DER, have been calculated. These were compared in percentage terms to National Grid's *Electricity Ten Year Statement (ETYS)* winter 2018/19 3-phase fault levels. The results at the Chapelcross 132kV busbar, the Dumfries GSP 132kV and 33kV busbars, and the Gretna 132kV busbar are given.

Figure 3.6

Chapelcross GSP, wider transmission and distribution networks



Three phase fault levels

- **Chapelcross 132kV:** 12.13kA (rms break)/30.45kA (peak make). The calculated fault level when fed from the Chapelcross 33kV anchor DER 3.2 per cent (rms break)/3.84 per cent (peak make) of the normal fault level.
- **Gretna 132kV:** 14.00kA (rms break)/37.56kA (peak make). The calculated fault level when fed from the Chapelcross 33kV anchor DER is 2.71 per cent (rms break)/2.98 per cent (peak make) of the normal fault level.
- **Dumfries 132kV:** 8.14kA (rms break)/20.17kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 4.55 per cent (rms break)/5.40 per cent (peak make) of the normal fault level.
- **Dumfries 33kV:** 11.76kA (rms break)/32.23kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 11.6 per cent (rms break)/12.35 per cent (peak make) of the normal.

Single phase fault levels

- **Chapelcross 132kV:** 13.07kA (rms break)/31.01kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 4.5 per cent (rms break)/5.22 per cent (peak make) of the normal fault level.
- **Gretna 132kV:** 17.34kA (rms break)/44.92kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 3.3 per cent (rms break)/3.4 per cent (peak make) of the normal fault level.
- **Dumfries 132kV:** 9.79kA (rms break)/23.44kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 5.72 per cent (rms break)/6.57 per cent (peak make) of the normal fault level.
- **Dumfries 33kV:** 3.10kA (rms break)/4.48kA (peak make). Therefore, the calculated fault level when fed from the Chapelcross 33kV anchor DER is 56.7 per cent (rms break)/64.96 per cent (peak make) of the normal fault level.

3.6.2.5 Summary of fault level calculations

Table 3.12 contains a summary of the fault level results for the Chapelcross case study network supplied from the 33kV anchor DER (the generator terminal voltage is also included).

Table 3.12

Chapelcross case study fault level summary

Voltage Level	Discussion	Rating
LV	At LV both the three phase and single phase to earth fault levels are largely unchanged from those that would be calculated for normal operating scenarios. The fault levels are dominated by the impedances of the transformers and longer LV feeder cables.	
	The performance of the LV protection for the black start scenario would therefore be similar to that experienced in normal operation.	
11 kV	The three phase fault levels at 11 kV range from 36% to 100% of those under normal operating conditions with an average around 60%.	
	The single phase to earth fault levels at 11 kV range from 68% to 98% of those under normal operating conditions with an average around 80%.	
	Lower fault levels will result in longer protection clearance times.	
	For a three phase fault at 132 kV the generator terminal initial volts are 0.72 pu. For a single phase to earth fault this value is 0.87 pu.	
	For a three phase fault at 33 kV the generator terminal initial volts are 0.65 pu. For a single phase to earth fault this value is 0.94 pu.	
	For a three phase fault at 11 kV the generator terminal initial volts are 0.88 pu. For a single phase to earth fault this value is 0.96 pu.	
	For a three phase fault at LV the generator terminal initial volts are 0.97 pu. For a single phase to earth fault this value is 0.99 pu.	
33 kV	The three phase fault level at the Chapelcross 33 kV GSP is about 14% of that under normal operating conditions leading to longer fault clearance times.	
	The single phase to earth fault level at the Chapelcross 33 kV GSP is about 59% of that under normal operating conditions. This is around the same level for a single grid transformer in service normally.	
132 kV	The three phase fault levels at 132 kV range from 2.7% to 5.4% of those under normal operating conditions.	
	The single phase to earth fault levels at 132 kV range from 3.3% to 6.6% of those under normal operating conditions.	

It can be seen that the LV (415V) fault levels, and the 33kV single phase to earth fault levels, are largely unchanged, implying that existing protections will be adequate. For all the other conditions, the operation of the protection will need to be assessed. The following section details a full protection assessment that has been undertaken given the fault levels calculated in this section.

3.6.3 Protection

Protection within electrical systems is defined as the ability to detect and isolate faults on the network which pose risk to personnel or other network components. It is important that this is considered under the specific scenario of islanded operation due to the lower fault levels identified in section 3.6.2.

Based on the Chapelcross GSP case study, and the SP Energy Networks protection policy documents, a summary of the expected typical protection functionality, characteristics and settings are given in table 3.13.

Table 3.13

Typical protection settings and operating times

Voltage Level	Protection Function	Scheme Type	Typical Sensitivity	Minimum fault current required to ensure operating time	Relay operating time at minimum current
132 kV	Busbar Protection	High Impedance	<1000 A	2000 A (2x)	<200 ms
	132 kV Feeder Main Protection	Solkor 'M'	125 A	250 A	135 ms
		132 kV Distance (overhead circuits)	Circuit-specific settings based on line parameters	Z1=80% Line Impedance, 0ms Z2=120% Line Impedance, 400 ms Intertripping or POTT scheme	Depends on S.I.R
	132 kV Feeder Backup Protection	OC	1045 A SI 0.40TM	2090 A (2x)	4.0 s
		EF	300 A SI 0.40TM	600 A (2x)	4.0 s
	132 kV Transformer Feeder MP	HV REF	59 A (15 %)	118 A	<50 ms
		Biased Differential	118 A (30%)	236 A	<50 ms
	132 kV Transformer Feeder BUP	HSOC	3000 A DT 10 ms	6000 A (2x)	10 ms
		OC	550 A SI 0.30TM	1100 A (2x)	3 s
		EF	300 A SI 0.20TM	600 A (2x)	2.0 s
33 kV	Busbar Protection	High Impedance	<250 A	500 A (2x)	<200 ms
	33kV Feeder MAIN Protection	Translay HHTA	220 A	440 A (2x)	~2 s
		MBCI Translay 'S'	400 A (L2-L3 fault)	800 A (2x)	<200 ms
		Toshiba GRL150	80 A (20%)	160 A (2x)	<200 ms
		Siemens 7SD52	60 A (15%)	120 A (2x)	<200 ms
		MPR(OLP)	With comms (LOW_SET) ΔOC=150 A, ΔEF=60 A Without comms (HIGH_SET) ΔOC = 450 A, ΔEF = 150 A	600 A (above I1 HIGHSET)	< 200 ms
		33kV Distance (overhead circuits)	Circuit-specific settings based on line parameters	Z1=80% Line Impedance, 0ms Z2=120% Line Impedance, 400 ms Intertripping or POTT scheme	Depends on S.I.R
	33kV Feeder BACKUP Protection	OC	600 A SI 0.475TM	1200 A (2x)	4.76 s
		EF	90A SI 0.55TM	180A (2x)	5.5 s
	33kV Transformer OCEF Protection	HSOC	1400A, Inst	2800A (2x)	<200 ms
		OC	200A SI 0.45TM	400A (2x)	4.5 s
		REF	236 A	472 A	< 50 ms
		BEF	200 A, Inst	400 A (2x)	<200 ms
11 kV	11kV Transformer - OCEF Protection	Dir. OC Backfeed into 33kV from 11kV	400 A SI 0.1TM	800 A (2x)	1 s
		REF	160 A, inst	320 A (2x)	<200 ms
		Standby EF	300 A SI 1.0TM	600 A (2x)	10 s
	11kV Feeder - Backup Protection	OC	375 A SI 0.4TM	750 A (2x)	4 s
		EF	90 A SI 0.575 TM	180 A (2x)	5.75 s
		SEF	21 A Def Time 15s	30 A (1.5x)	15 s
	11kV Feeder - MAIN Protection	Solkor 'A'	720 A (L2-L3 fault)	1440 A (2x)	<200ms
		Solkor 'R'	375 A (L2-L3 fault)	750 A (2x)	<200ms
	11kV Distribution Transformer - OCEF	OCEF	60A OC EI 0.2TM	120 A (2x)	5.33 s
		TLFs	7.5 A TLF (50/5A CT)	170 A for Tx LV fault	<1s nominal
		Switchfuse	50 A HV Fuse	315 A for Tx LV fault	<1s nominal
LV	LV Network Fuses	LV Feeder Fuses	400 A	1200 A (3 x) for operation	10-20 seconds
				3000 A for 1s operation	1 s
		LV Service Fuse	100 A	300 A (3 x) for operation	4 s
				700 A for 1s operation	1 s

3.6.4 Protection performance assessment

The typical and actual protections at each relevant node on the Chapelcross GSP case study, and wider transmission and distribution network, were identified. Based on the fault levels calculated when the network is energised from a single 33kV connected DER at Chapelcross, the performance of the protection at each node was then assessed, using the existing network settings where applicable, to determine if the protection would still operate correctly.

An example is given below of the assessment of the overcurrent protection relay on a 33kV feeder circuit breaker at Chapelcross GSP. The associated grading curves are given in figure 3.7.

3.6.4.1 33kV overcurrent (Chapelcross) protection assessment

Based on the fault levels calculated from the Chapelcross anchor generator only, the performance of typical 33kV protection is assessed.

The actual settings on the 33kV feeder to the anchor generator at Chapelcross are as follows:-

- 960 A
- Curve Type SI
- TM 0.25.

There is also overcurrent protection on the 33kV side of the generator transformer:-

- I>1,000 A
- Curve Type VI
- TM 0.45.

The generator also has under-impedance protection which is set to cover 100 per cent of its transformer impedance.

The 11kV generator protection has the following settings:-

- I>4,375 A
- Curve Type DT
- TD 3 s.

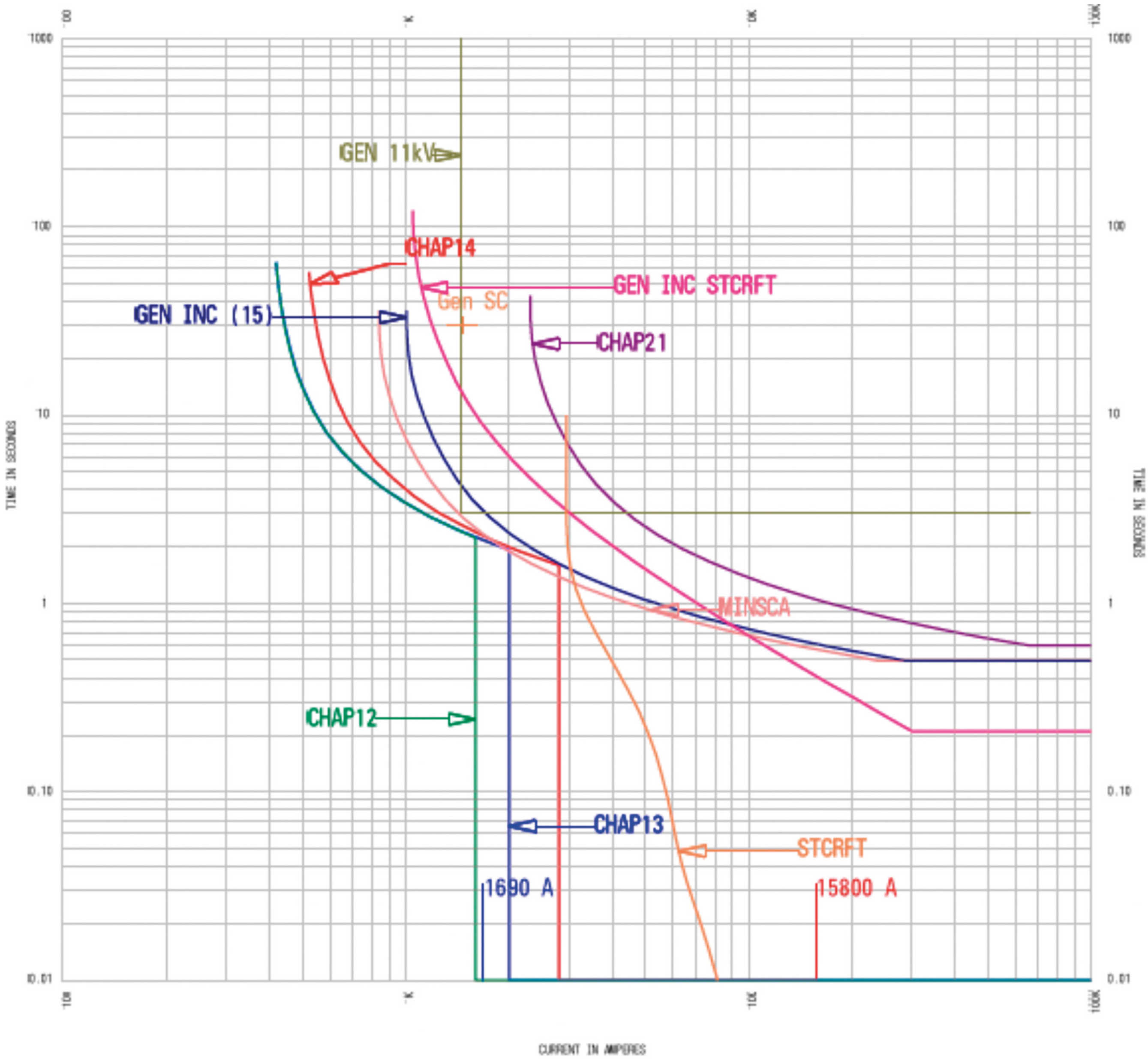
The three phase fault level of the Chapelcross 33kV switchboard is 1.69kA. The fault level at the Chapelcross 33kV switchboard is equivalent to 11 per cent of the 15.8kA fault level given in the LTDS.

The overcurrent grading curves are shown in figure 3.7. The magnitude of fault current is insufficient to guarantee that all outgoing transformer feeders will operate instantaneously for faults on the 33kV system. The generator protection would trip in three seconds for fault currents in excess of 140 per cent of its rating. There is a lack of grading between the generator protection and some of the outgoing feeders. Fault clearance times on outgoing feeders could be around two seconds for bolted faults.

The highest set outgoer is the feeder to Minsca which has a pick-up of 800 A. The fault level of 1.69kA is 2.1 times this value and therefore meets the requirement of being at least twice the relay setting.

The 33kV fault current is equivalent to 96.6 MVA. The grid transformers at Chapelcross are rated at 90 MVA and therefore this fault level is only 107 per cent of the transformer rating.

Figure 3.7
Typical 33kV overcurrent protection (Chapelcross) grading curves



33 kV OC Chapelcross.tcc Ref Voltage: 33000 Current Scale: x 1

3.6.4.2 Protection assessment summary

The results of a protection assessment on all the relevant Chapelcross case study distribution and transmission network protections, based on the network being energised from the Chapelcross anchor generator only, are summarised in the following tables:

Table 3.14 contains a summary of the LV and 11kV protection issues identified, along with potential mitigations.

Table 3.15 contains a summary of the 33kV protection issues identified, along with potential mitigations.

Table 3.16 contains a summary of the 132kV protection issues identified, along with potential mitigations.

Table 3.17 contains a summary of the protection issues identified, along with potential mitigations, with energising a remote 33kV network. That is the anchor generator at Chapelcross back-energising the 132kV network, which in turn energises a 132/33kV transformer to supply a remote 33kV network.

Table 3.14

LV and 11kV protection assessment summary

Voltage	Protection Function	Description	Mitigation	Rating
LV	Overcurrent	Overcurrent protection on the LV network is primarily provided by fuses. Fault levels on the LV network are dominated by the impedance of the transformers and longer cable feeders. Provided the fault level at 33 kV is at least 500 A (28.5 MVA) the operation of the LV protection will be similar to that during normal supply.		
	Earth Fault	Earth fault protection on the LV network is primarily provided by fuses. Earth fault levels on the LV network are dominated by the impedance of the transformers and longer cable feeders. Provided the fault level at 33 kV is at least 500 A (28.5 MVA) the operation of the LV protection will be similar to that during normal supply.		
11 kV	Transformer Incomer Overcurrent	The 11 kV fault levels will be affected by the fault level at 33 kV. The percentage change in fault level will be greater for substations with less impedance to 33 kV. Assuming a 33kV fault level of 60 MVA typical fault levels at 11 kV could be 30-70% of normal values. Incomer protection may not be sensitive enough and/or too slow to operate.	A second setting group could be applied for Blackstart operation or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	
	Transformer Incomer Directional Overcurrent	There should be sufficient fault current to operate the directional overcurrent protection.		
	Transformer Incomer Earth Fault	The 11 kV fault levels will be affected by the fault level at 33 kV. The percentage change in fault level will be greater for substations with less impedance to 33 kV. Assuming a 33kV fault level of 60 MVA typical fault levels at 11 kV could be 50-80% of normal values. There is little change in the performance of the 11 kV earth fault protection.		
	Transformer REF	The 11 kV earth fault levels are sufficient to allow satisfactory operation of the restricted earth fault protection.		
	11 kV Feeder Main Protection	The sensitivity of the line differential protection will need to be checked.	Depends on relay types, alternative relays may be required.	
	11 kV Feeder Overcurrent	Protection may not be sensitive enough or too slow to operate.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	
	11 kV Feeder Earth Fault	It is unlikely that changes will be required to the feeder earth fault setting.		
	Transformer Feeder Overcurrent	It is unlikely that changes will be required to the transformer feeder overcurrent settings.		
	Transformer Feeder Earth Fault	It is unlikely that changes will be required to the transformer feeder earth fault settings.		
	Generator Protection	Voltage and frequency transients could be sufficient to trip G59/G99 protection.	A second setting group may be required during Blackstart. This may require relay replacement.	

Table 3.15
33kV protection assessment summary

Voltage	Protection Function	Description	Mitigation	Rating
33 kV	Grid Transformer Incomer Transformer Differential	Typically transformer differential would operate for a fault equal to 30% of transformer rating. There is sufficient fault current to operate in Blackstart.		🟢
	Grid Transformer Incomer LV REF	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to REF if the grid transformer ET is in circuit. If the grid transformer earthing transformer is not in circuit the CT in the neutral will not see any current and the scheme will provide unrestricted EF protection for faults on the 33 kV side of the GT.		🟢
	Grid Transformer Incomer LV SBEF	If the grid transformer earthing transformer is used no changes are required to the SBEF.		🟢
	Grid Transformer Incomer LV SBEF	If the grid transformer was used to energise the transmission system with its ET out of circuit the REF on the incomer would act as EF protection for faults on the 33 kV side of the GT.		🟢
	Busbar Protection	Policy requirements for the 33 kV busbar protection can be met in the Blackstart scenario provided the 33 kV fault level is around 1000 A.		🟢
	33 kV Feeder Main Protection	The sensitivity of the line differential protection will need to be checked.	Depends on relay types, alternative relays may be required.	🟡
	33 kV Feeder Distance Protection	In the Blackstart scenario the system impedance will be higher and the relay voltage lower for a fault. The operation of each distance protected circuit will have to be checked. Operating times could be slower.	The operation of each distance protected circuit will have to be checked.	🟡
	33 kV Feeder Backup Overcurrent	Protection may not be sensitive enough or too slow to operate.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	🟡
	33 kV Feeder Backup Earth fault	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to EF.		🟢
	33 kV Feeder to Local Generator	If earthing is provided by the GT earthing transformer or ETs connected to the 33 kV GSP opening the feeder breaker to the local generator transformer will leave the 33 kV side of the generator circuit unearthed.	NVD protection could be fitted at the 33 kV terminals of the generator transformer. Alternatively opening of the feeder breaker would have to trip the generator.	🟡
	33 kV Transformer HSOC	There maybe insufficient fault current to operate the HSOC protection.	A second setting group could be applied for Blackstart operation. The relay may need inrush blocking to prevent this element spuriously operating during transformer energisation. If a second setting group is not possible additional protection or relay replacement may be required.	🟡
	33 kV Transformer OC	Protection may not be sensitive enough or too slow to operate.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	🟡
	33 kV Transformer BEF	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to BEF.		🟢

Table 3.16
132kV protection assessment summary

132 kV	Busbar Protection	There is insufficient fault current to operate the busbar protection.	An alternate busbar scheme could be added but this is likely to need additional relays, stabilising resistors and possibly CTs. Overcurrent protection can be set to operate for BB faults but will be slower (with lower fault levels no thermal issues). Faster operation could be achieved by sacrificing grading.
	132 kV Feeder Main Protection	The sensitivity of the line differential protection will need to be checked.	Depends on relay types, alternative relays may be required.
	132 kV Feeder Distance Protection	In the Blackstart scenario the system impedance will be higher and the relay voltage lower for a fault. The operation of each distance protected circuit will have to be checked. Operating times could be slower.	The operation of each distance protected circuit will have to be checked.
	Transformer Differential	Typically transformer differential would operate for fault equal to 30% of transformer rating. There is sufficient fault current to operate in Blackstart.	
	GT HV REF	There is sufficient fault current to operate the HV REF. This function only protects the transformer primary winding. It will not protect the 132 kV feeder to the transformer.	Standby earth fault protection should be added to the neutral of the primary winding.
	132 kV Transformer HSOC	There is insufficient fault current to operate the HSOC protection.	A second setting group could be applied for Blackstart operation. Voltage controlled overcurrent protection may be required if the load current is close to the fault current. If a second setting group is not possible additional protection or relay replacement may be required.
	132 kV Transformer OC	Protection will not operate with existing settings.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.
	132 kV Transformer EF	In Blackstart the EF relay at the switchboard end will not protect the feeder to the transformer. It will offer some protection for remote faults. Clearance times will be too slow.	A second setting group could be applied for Blackstart operation. To protect the feeder to the GT SBEF protection will be required on the neutral of the transformer's primary winding.
	132 kV Feeder Overcurrent	With existing settings protection will not operate for Blackstart.	A second setting group could be applied for Blackstart operation or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.
	132 kV Feeder Earth Fault	For Blackstart the existing settings may not be sensitive enough and clearance times too slow.	A second setting group could be applied for Blackstart operation or additional protection added. If a second setting group is not possible additional protection or relay replacement may be required.

Table 3.17
Remote 33kV protection assessment summary

Voltage	Protection Function	Description	Mitigation	Rating
Remote 33 kV	Grid Transformer Incomer Transformer Differential	Typically transformer differential would operate for fault equal to 30% of transformer rating. There is sufficient fault current to operate in Blackstart.		
	Grid Transformer Incomer LV REF	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to REF at remote GSP.		
	Grid Transformer Incomer LV SBEF	No changes are required to the SBEF.		
	Grid Transformer Incomer OC	Protection may not operate with existing settings.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	
	Busbar Protection	Policy requirements for the 33 kV busbar protection can be met in the Blackstart scenario provided the 33 kV fault level is around 1000 A.	Actual fault level will need to be confirmed.	
	33 kV Feeder Main Protection	The sensitivity of the line differential protection will need to be checked.	Depends on relay types, alternative relays may be required.	
	33 kV Feeder Distance Protection	In the Blackstart scenario the system impedance will be higher and the relay voltage lower for a fault. The operation of each distance protected circuit will have to be checked. Operating times could be slower.	The operation of each distance protected circuit will have to be checked.	
	33 kV Feeder Backup Overcurrent	Protection may not be sensitive enough or too slow to operate.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	
	33 kV Feeder Backup Earth fault	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to EF.		
	33 kV Transformer HSOC	There is unlikely to be sufficient fault current to operate the HSOC protection.	A second setting group could be applied for Blackstart operation. The relay may need inrush blocking to prevent this element spuriously operating during transformer energisation. If a second setting group is not possible additional protection or relay replacement may be required.	
	33 kV Transformer OC	Protection may not be sensitive enough or too slow to operate.	A second setting group could be applied for Blackstart operation and/or voltage controlled overcurrent applied that would reduce settings when a fault is present. If a second setting group is not possible additional protection or relay replacement may be required.	
	33 kV Transformer BEF	In Blackstart the 33 kV earth fault level should be similar to when the GSP is supplied by a single grid transformer. No changes required to BEF.		

3.6.4.3 Protection performance conclusions

From the results in table 3.14 to table 3.17, the following conclusions can be made for power island operation:

1) LV protection – The existing overcurrent and earth fault protection will operate correctly.
2) 11kV protection – Some 11kV protection, overcurrent and earth fault will need revised settings.
3) 33kV protection – The overcurrent protection will need revised settings (earth fault will operate correctly).
4) 132kV protection – Revised setting will be required on most 132kV protections. This may not be practical for the 132kV busbar protection, however other protections may be acceptable to cover a busbar fault with the low fault levels.
5) Remote 33kV GSP protection – Some overcurrent protections will need revised settings.

Additional considerations:

i) Not all relays will be capable of having second settings groups applied. This may require additional relays or the relays to be changed with modern equivalents.

ii) For Black Start, it may be acceptable to rationalise the protections available and not have the same level of discrimination. For example, at a primary substation only the transformer 11kV circuit breaker could have revised settings resulting in the loss of the primary for an 11kV feeder fault.

iii) Existing relays may not be capable of voltage-controlled overcurrent; therefore a replacement relay may be required. Those that are capable will require a voltage signal.

iv) Voltage and frequency transients at 33kV and 11kV may be severe and therefore faster clearance times may be required.

v) G59/G99 voltage and frequency settings at the DER may need to be relaxed; this would require a second group setting or additional protection.

vi) Under-frequency load shed panels at the grid 33kV substations may need to be switched out of service.

3.6.4.4 Network protection issues register

The network protection issues are summed up as a single issue in the issues register in table 3.18.

Table 3.18

Network protection issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
Protection	P1	There may be insufficient fault level for existing protections to operate adequately for a distribution power island.	The protection will need to be able to detect and clear faults before the network can be energised from DER.	A protection assessement should be carried out on all potential power islands to identify protection issues. A policy should be developed for the minimum protections required for a Black Start scenario. Most protection issues can be overcome by having separate Black Start settings.	

3.7 Distribution network – power system studies

3.7.1 Steady-state studies

Steady-state load flow and fault level studies were performed for the following case studies: Chapelcross (SPD), Sankey Bridges (SPM) and Maentwrog (SPM). These case studies were selected based on the opportunities they provide to study various network topologies, various DER types and restoration strategies.

A short description of the case studies together with reasons for selecting them for steady-state studies is shown below. See the appendix (Appendix C – case study data sheets) for the case study data sheets.

Chapelcross network area has a total generation capacity of 93.8 MW connected at 33kV. The group contains a single anchor generator (biomass) with a net export capacity of 45 MW, two connected wind farms with a combined export capacity of 48.8 MW and a contracted wind farm with an export capacity of 30 MW (to be energised in 2019). This group has a lot of excess generation compared to the maximum load (52.1 MW) and thus, realistically could be used to energise up to the 132kV network. Moreover, the network area has long circuits (including the connection circuit of the anchor generator), which gives the opportunity to study potential voltage exceedances.

Sankey Bridges network area has about 54 MW of anchor generation at three sites (gas). There are no wind farms or solar parks connected at 33kV. This group is supplied from the Carrington/Fiddlers Ferry 132kV group which has a 138 MW CHP plant at Carrington. The Sankey Bridges case study is representative for most of the SPM network as it has a highly meshed network. Multiple primary (33/11kV) substations share the same interconnected network at lower voltage levels (11kV and LV) in normal operation. (These are called primary groups.). Please see the appendix (Appendix K – existing requirements and test procedures) for a description of the SPM network. In Sankey Bridges, the demand of these primary groups varies between 9.1 MW and 20.7 MW, but could be higher in other SPM areas. This case study offers the possibility to study the case in which a 33kV anchor generator energises the 132kV network, including the 132kV plant in Carrington.

Maentwrog network area has 39.8 MW of anchor generation at two hydro sites, with an additional 46 MW of wind and solar generation (of which 8 MW solar was considered in the studies). This case study provides the opportunity to study a mixture of hydro anchor generators, wind and solar, as well as issues potentially arising from the presence of long rural lines.

A wide variety of restoration scenarios and combinations of them have been analysed in the case studies and these are summarised below:

- island initiation from a 33kV anchor and establishing a 33kV island
- anchor generators create 33kV individual islands separately (for Sankey Bridges case only)
- the anchor generator initiates the Black Start to energise the other generators and create a 33kV shared island
- bottom to top restoration from the 33kV anchor generator for Chapelcross and Sankey Bridges case studies (the anchor generator energises the 132/33kV transformer and 132kV network); in Sankey Bridges case study only, the restoration scenario also includes the energisation of the 132kV synchronous generator in Carrington.
- the load is taken on simultaneously with the primary transformer (the 11kV circuit breaker closed to take on the load)
- the load is taken on in a subsequent step, following the energisation of the primary transformer
- the anchor generator energises the backbone network of the island first (including primary transformers), and then takes on the load
- consumers are fed as the island grows, i.e. the load is taken on as the primary substation is energised and before energising the next circuit
- for the Sankey Bridges case study: the 11kV and LV highly meshed network of primary groups is not practical to split (large block loads in line with the total demand on a primary group, see description of SPM network in Appendix K – existing requirements and test procedures)
- for the Sankey Bridges case study: the 11kV and LV highly meshed network of primary groups could be split (smaller block loads in line with the demand of primary transformers, see description of SPM network in Appendix K – existing requirements and test procedures).

The load flow results including generator MW and MVAr output, power flows, voltage profile and voltage step change across the network were recorded for each restoration step. Fault level results at all buses in the island were also extracted at each step.

The following sections provide an overview of the technical issues based on the results of the network system studies and research. Detailed information about studies is shown in the Appendix I – power system studies, SPM case studies assessment and Appendix J – transformer energisation studies.

3.7.1.1 Exceedances of voltage limits
Throughout all scenarios, voltages were generally well within the typical statutory +/-6 per cent limits with a few exceptions discussed below.

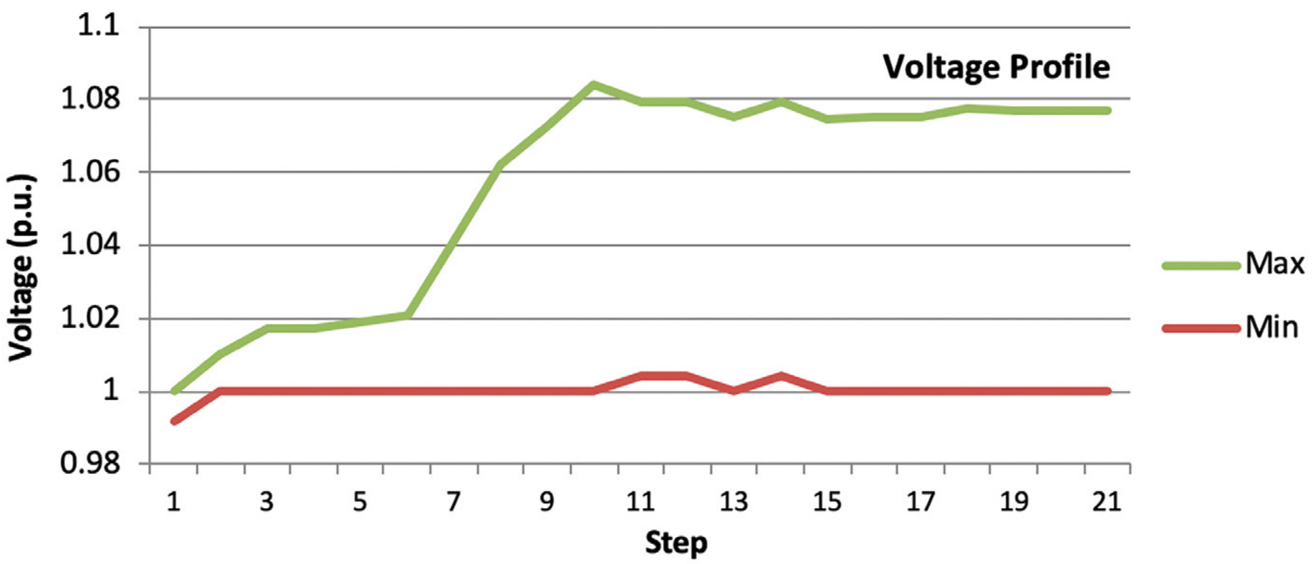
Voltages exceeding the +6 per cent statutory limit
High voltages, exceeding the +6 per cent statutory limit, were seen on the 11kV side of the 33/11kV primary transformers following switching on transformers without taking on the load (open circuit) for Chapelcross and Sankey Bridges (minor exceedances) case studies. Such exceedances can be seen graphically in figure 3.8 and figure 3.9 which depict the voltage profile (maximum and minimum voltage) for each restoration step and for each bus in the power island in Chapelcross and Sankey Bridges case study respectively.

This can be explained by the fact that, in certain situations, prior to a blackout, the primary transformer may have been heavily loaded and the tap changer will have tapped to a position to keep the 11kV voltage within acceptable limits. If the transformer is then energised without taking on the load, the open circuit 11kV voltage may exceed the +6 per cent statutory limit. There will also be no local LV supplies available to power the tap change motor and reduce the 11kV voltage.

In Maentwrog case study, voltages slightly exceeding the +6 per cent statutory limit were seen at the 33kV substation where an existing capacitor bank was switched-on for the purpose of improving the voltage profile in the area. Such exceedance can be seen graphically in figure 3.10 which depicts the voltage profile (maximum and minimum voltage) for each restoration step and for each bus in the power island.

In Sankey Bridges case study, in the scenario in which a 33kV anchor generator is energising the 132kV network and the 132kV connected synchronous generator in Carrington, the 132kV restoration route with the minimum reactive power gain, the circuits were carefully selected in order to avoid exceedances of the voltage upper limits at 132kV during low load conditions (figure 3.9). The selection of other 132kV routes would have generated voltage exceedances of the +6 per cent statutory limit due to the reactive gain of the circuits.

Figure 3.8
Voltage results in Chapelcross case study (scenario III)



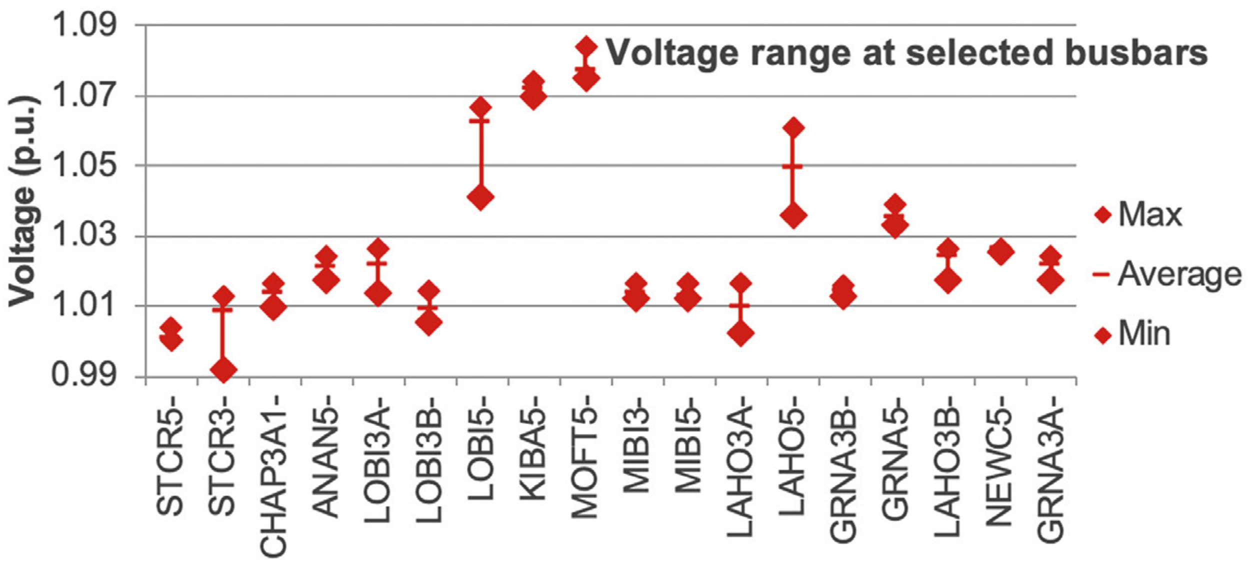
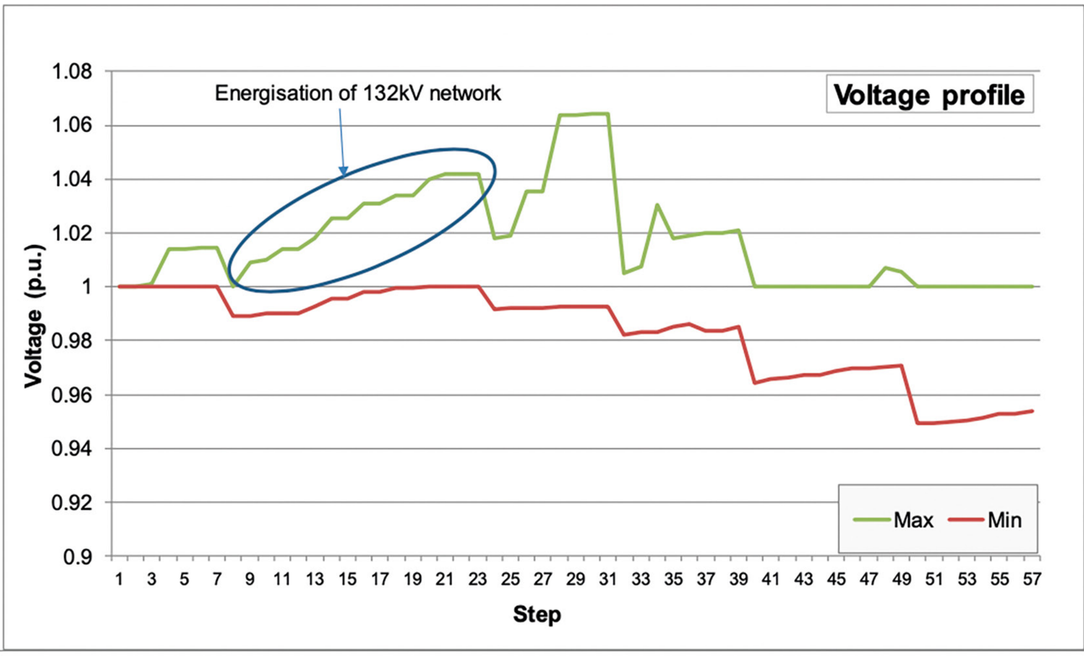


Figure 3.9

Voltage results in Sankey Bridges case study (scenario IV)



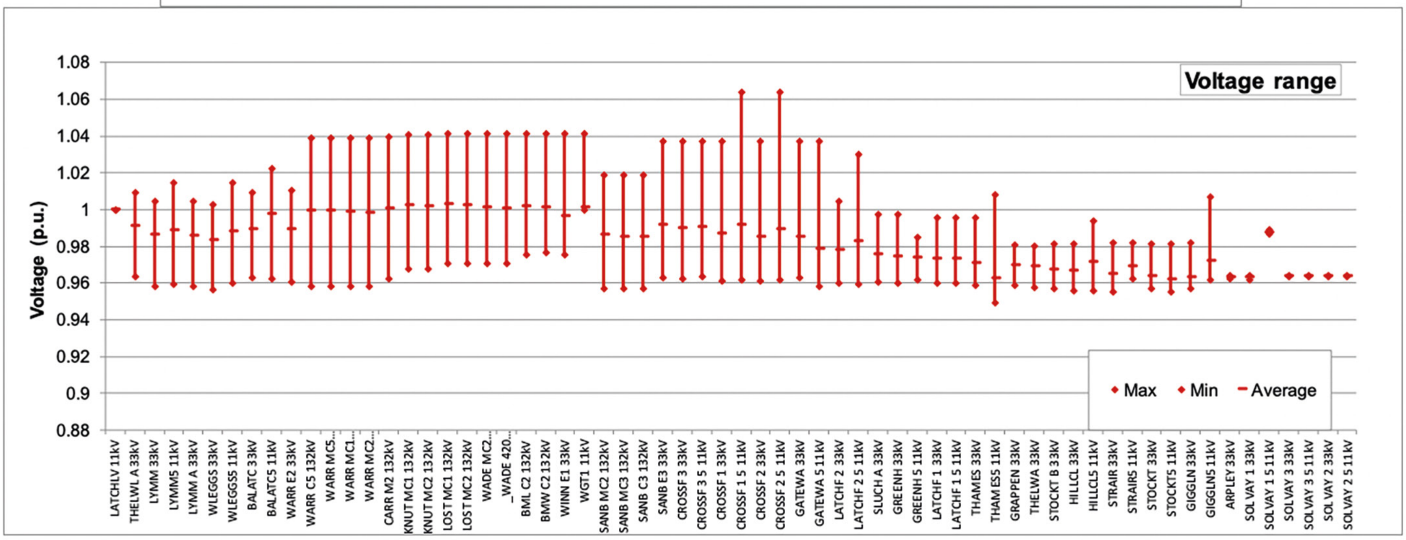
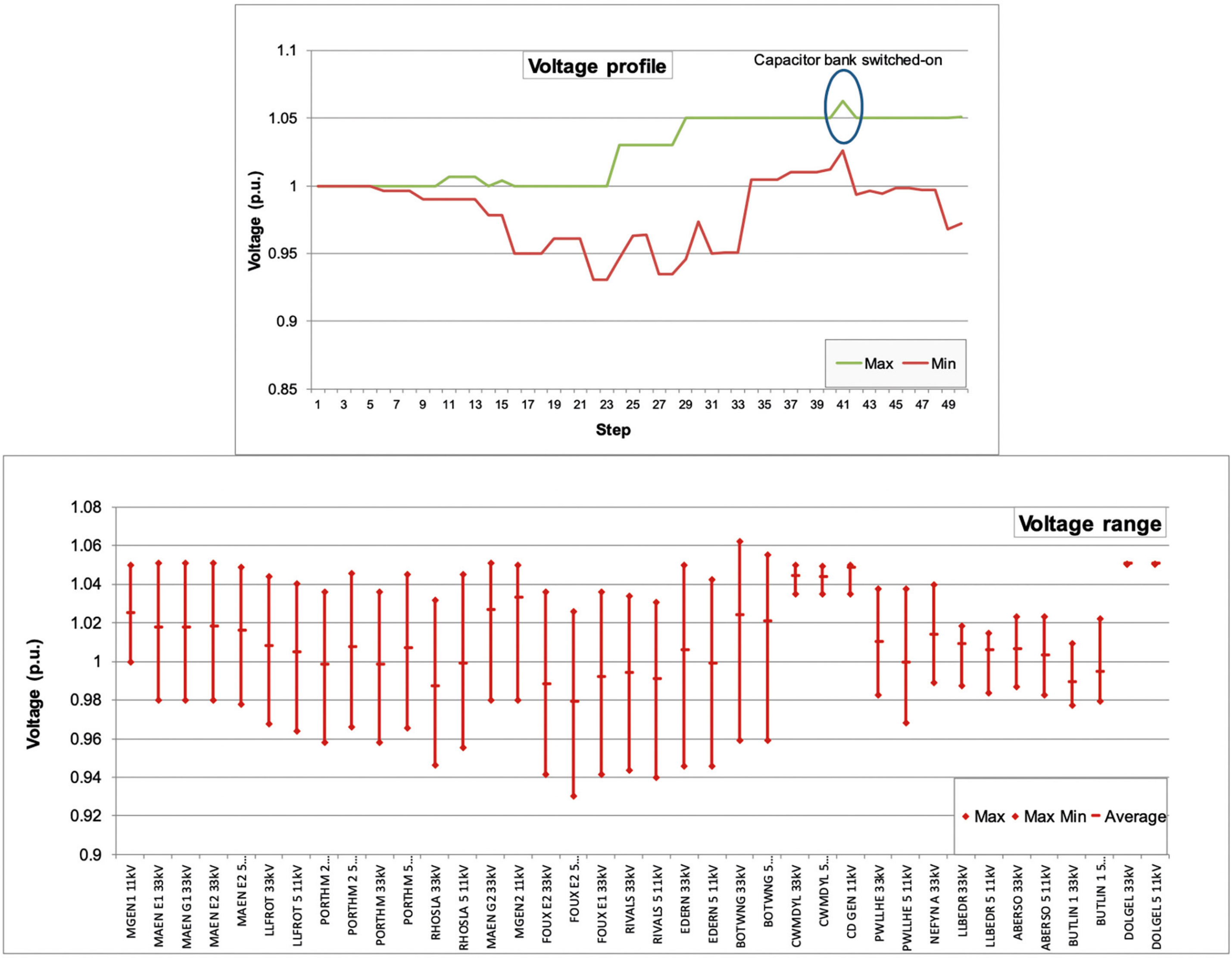


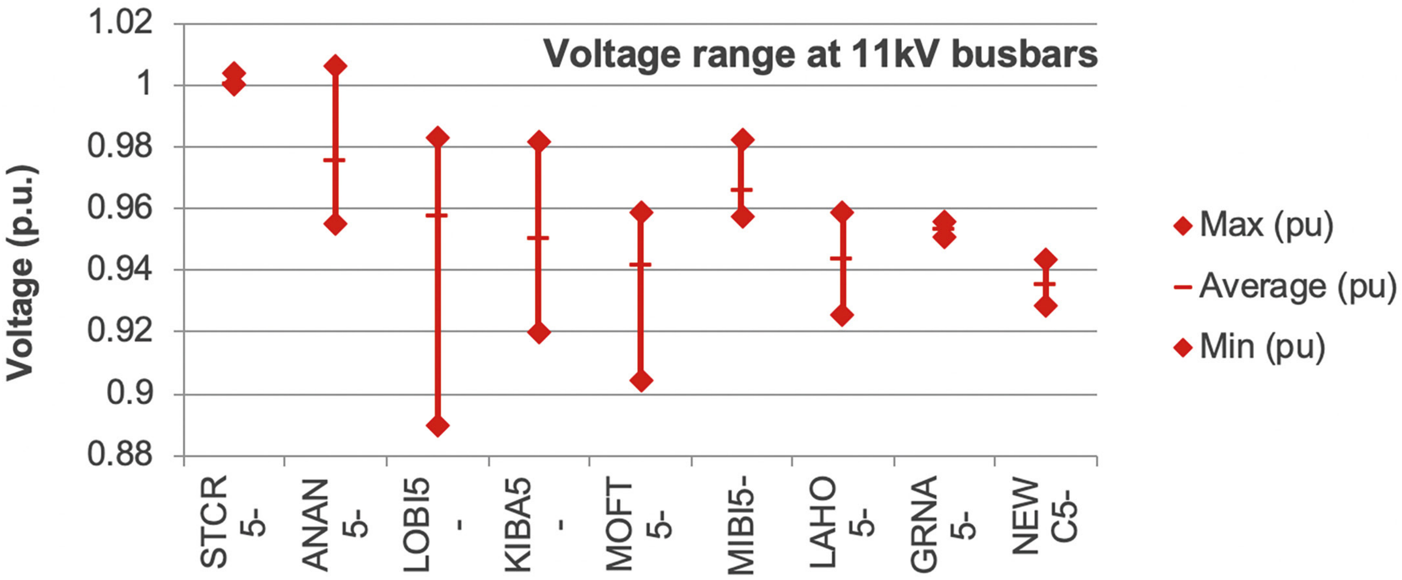
Figure 3.10
Voltage results in Maentwrog case study (scenario V)



Voltages exceeding the -6 per cent statutory limit
In Chapelcross case study, voltages of 0.89 p.u., exceeding the -6 per cent statutory limit, were seen at the 11kV busbars of primary substations (figure 3.11). The network topology where these voltages were recorded consisted of three primary substations banked onto a single, long rural 33kV circuit. Scenario II shows that if the automatic taping of the primary transformer is available, these violations are removed. Further details are given in the Appendix. Appendix H – power system studies, SPD case studies assessment.

In Maentwrog case study, voltages of 0.93 p.u., slightly exceeding the -6 per cent statutory limit, were seen at the furthest end from the anchor generator in the power island, due to the long 33kV lines (figure 3.10). In order to bring the voltages back to the statutory limits and avoid further exceedances, two measures have been taken at specific steps during the restoration process: the anchor generators voltage setpoint was increased and an existing capacitor bank was switched on. It should be noted that in all scenarios for Sankey Bridges and Maentwrog case studies, all transformer taps have been locked to the position prior to Black Start as a conservative assumption. In this respect, it can be concluded that there is room available in the power island for more voltage control via tap changing.

Figure 3.11
Voltage results in Chapelcross case study (scenario I)



The restoration plans need to be carefully selected to avoid exceedances of voltage limits at each restoration step. Possible solutions for improving the voltage profile and avoiding voltage limits exceedances during restoration could be:

- Energising the 33/11kV primary transformer together with its load connected (the 11kV circuit breaker closed to connect the load). However, consumers may experience large voltage dips due to transformer inrush. Another option could be to reduce the voltage levels at 33kV (but still within acceptable limits) prior to transformer energisation which would in turn reduce the resulting voltage magnitude at its 11kV terminals.
- to prioritise the energising of multiple DERs in the power island to increase voltage control capability
- if possible, renewable DERs (eg. Wind farms and solar) to provide reactive power support as much as they can
- taking on load before back-energising the 132kV or transmission network to compensate for the reactive gain of the circuits and avoid exceedances of the upper statutory limit
- utilising existing reactive power compensation devices and transformer taps to control voltage where possible.

3.7.1.2 Exceedances of voltage step change limits

The voltage step changes seen in the steady state studies are well within Distribution Code guidelines of +/-10 per cent for infrequent events.

In all case studies, the largest negative voltage step changes generally occurred at the primary substations due to load pick-up.

In Chapelcross case study, the largest positive changes occurred when the second transformer at primary substations was energised, reducing the impedance between load and source.

In Sankey Bridges and Maentwrog case studies, the largest positive voltage changes generally occurred when a capacitor bank was switched on, or following an increase in the generator's voltage setpoint.

While these steady state studies have not shown limit exceedances, these may occur due to the low fault level in the power island. Future studies in the design stage will also take into account the strength of the system.

3.7.1.3 Generator reactive power limits

For the specific restoration scenarios studied, the generators have not reached their reactive power limits; however, this could represent an issue. DERs in the power island may not have sufficient reactive power capability to sustain the growth of the island and to maintain the voltages within the acceptable limits.

Possible solutions for this could be:

- reactive load banks installed at the DER anchor generator
- specifying higher MVAr requirements for anchor generators. ER-G99 requires a power factor range of 0.92 (lead), more onerous than ER-G59 requirement of 0.95 (lead).

3.7.1.4 Thermal overloads

Thermal overloads occurred in a specific scenario in Maentwrog case study due to the insufficient capacity of a 33kV circuit to transport the power from the anchor DER to the demand area. The energisation of a solar park, assuming full solar energy availability, aided the anchor generators to expand the island.

3.7.2 Transformer energisation studies

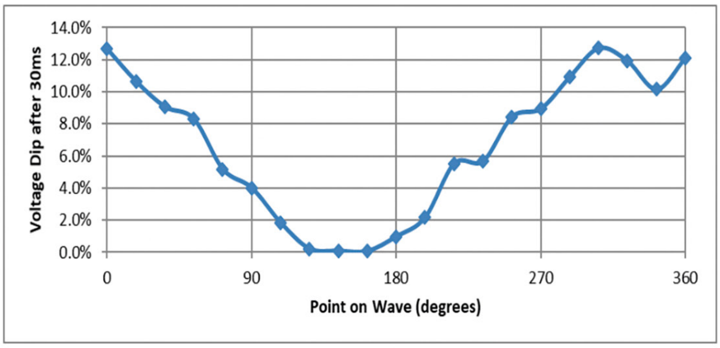
Transformer energisation (inrush) studies were undertaken to examine voltage dips at concerned substation busbars when a 33/11kV primary transformer is energised in the power island initiated by a 33kV anchor generator. When a transformer is energised, it may draw a large transient current from the sources, resulting in a temporary voltage dip on the network. The voltage dip is dependent upon the magnitude of the transformer inrush current, the strength of the network, remnant flux on the transformer, and the point-on-wave (POW) circuit breaker switching time. As the network in the power island is much weaker, in terms of the strength of the network represented by fault levels, than the network supplied by a bulk power system, voltage dips resulting from transformer energisation is considered a concern.

The Chapelcross case study was used as a base case for this analysis. Various network parameters were then changed in order to simulate a variety of network conditions, resulting in a total of ten cases. The changes applied refer to: different voltage magnitudes prior to transformer energisation, various impedance values for the 33kV feeder connecting the anchor generator, higher demand in the area, size of anchor generator, various primary transformer sizes and inrush characteristics. Results for the worst-case POW and 50 per cent probability for a random POW switching, 30ms after energisation, were recorded for all scenarios. Detailed study results are presented in Appendix I – power system studies, SPM case studies assessment.

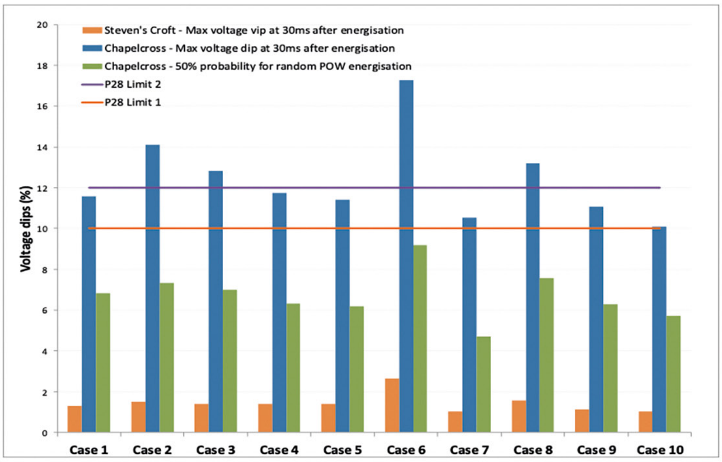
Figure 3.12 (a) and (c) show an extract of the results for the case 3 (base case), together with a summary of the voltage dip results at Chapelcross GSP 33kV for all ten cases against the Engineering Recommendation (ER P28) and Distribution Code limits for infrequent events (b).

Figure 3.12

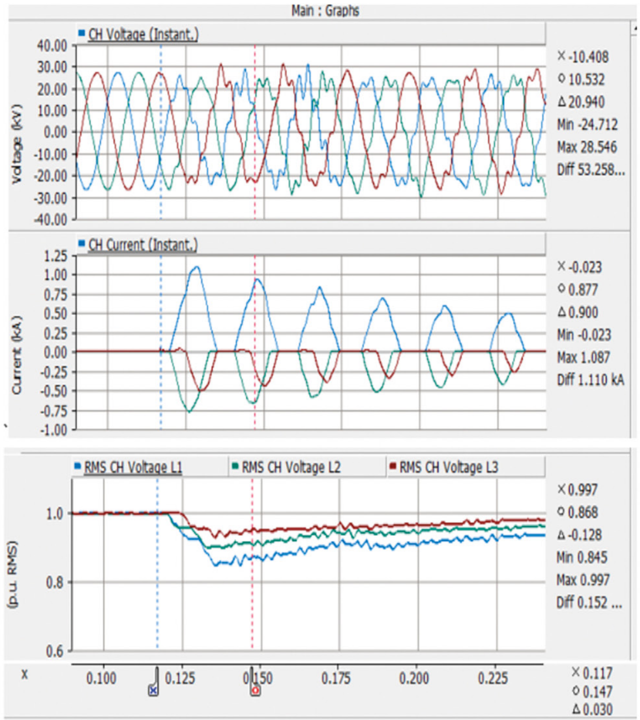
Primary (33/11kV) transformer inrush results at Chapelcross GSP



(a) Voltage dip results for various POW switching cases, case 3



(b) Maximum and 50% probability POW for all cases against limits



(c) Transformer energisation detailed results, maximum POW, case 3

The study results (figure 3.12 b) show that voltage dips with 50 per cent probability of occurrence at Chapelcross GSP 33kV busbar are less than the 10 per cent limit for all cases.

The most onerous voltage dips corresponding to the worst-case POW exceed the ER P28 10 per cent limit in all cases and the 12 per cent limit in four cases, however they are within the 20 per cent limit for equipment immunity recommended in "Voltage Dip Immunity of Equipment and Installations", published by CIGRE/CIRED/UIE Joint Working Group C4.110, 2010.

It is considered that the voltage dip and voltage magnitude would thus be unlikely to trigger tripping of motors and malfunction of equipment in the power island in accordance with the CIGRE document.

The results at the Steven's Croft DER are well within the 10 per cent limit in all cases.

It is concluded that transformer energisation may be an issue depending on the strength of the island (largely dependent on the fault contribution of the synchronous DERs) and the features of the transformer.

The following solutions may solve the transformer energisation challenges:

- point-on-wave switching devices to control the moment of circuit breaker closing
- reduce the voltage levels (but still within acceptable limits) prior to transformer energisation
- consider relaxation of voltage limits during Black Start
- for generator transformer energisation, consider ramping up the generator voltage with the transformer in service.

3.7.3 Power system studies issues register and conclusions

Please see table 3.19 for overall issues register related to the power system studies.

Table 3.19
Power system studies issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
Network System Studies	S1	Opening circuit breakers to create restoration paths and reduce block loading in SPM	Most of the SPM network is highly meshed, with interconnection at all voltage levels. This can pose challenges when opening circuit breakers to create restoration paths. Moreover, primary substations (33/11kV) share the same interconnected network at lower voltages (11kV and LV) in normal operation.	Splitting the 11kV and LV meshed network by establishing multiple open points in the primary group prior to the Black Start would ensure that the size of the block loads is reduced to the capacity of primary transformers, reducing the impact on the DER. Confirmation of its practicality requires further detailed analysis for each specific primary group. If the primary groups cannot be practically split, then solutions to take on larger block loads consistent with the full primary group load need to be identified, e.g. expanding the island system to energise multiple DERs and increase online generation capacity prior to taking on large block loads, load banks installed at the DER anchor generator site to compensate for the connection of large block loads.	
Network System Studies	S3	High voltages on the 11kV side of the primary 33/11kV transformer if energised open circuit	Prior to a black out, the primary transformer may have been heavily loaded and the tap changer will have tapped to a position to keep the 11kV voltage within acceptable limits. If the transformer is then energised without the load, studies have shown that the open circuit 11kV voltage may be up to 10% high. There will also be no local LV supplies available to power the tap change motor and reduce the voltage.	Energise the primary 33/11kV transformer together with its load connected (the 11kV circuit breaker closed to connect the load). However, the consumers may experience large voltage dips due to transformer inrush. Reduce the voltage levels at 33kV (but still within acceptable limits) prior to transformer energisation	
Network System Studies	S2	Insufficient reactive power in the power island which can generate voltage exceedances	DERs may not have sufficient reactive power capability to sustain the growth of the island and to mainain voltages within the acceptable limits	Prioritise the energisation of multiple DERs in the power island If possible, renewable DERs (WF, SF) to provide reactive power support as much as they can Taking on part of load to reduce voltage magnitude Utilising existing reactive power compensation devices and transformer taps to control voltage Reactive load banks installed at the DER anchor generators Specifying higher MVAr requirements for anchor generators. ER-G99 requires a power factor range of 0.92 (lead). Generators in Scotland are presently required to have this capability but this is not the case elsewhere in the UK The restoration plans need to be carefully selected to avoid exceedances of voltage limits	
Network System Studies	S4	High voltage step changes	High voltage step changes may occur in weak systems such as power islands	Dynamic analysis in the Design Stage will further study this issue	
Network System Studies	S5	Voltage dips due to transformer energisation	Due to low fault levels in the power island, voltage dips may occur during transormer energisation	Point-on-wave switching devices to control the moment of circuit breaker closing Reduce the voltage levels (but still within acceptable limits) prior to transformer energisation Consider relaxation of voltage limits For generator transformers, consider ramping up the generator voltage with the transformer in service	

Preliminary power system studies were undertaken on several of the case studies, in SPD and SPM.

- Voltage profile, voltage step change, power flows, generator reactive capability and transformer energisation (inrush) were assessed. Some scenarios are highlighted where high and low voltages, excessive voltage dips or generator reactive capability issues may arise. These are not deemed to be critical issues with potential solutions being proposed.
- About 80 per cent of the SPM network is designed and operated as a meshed network with interconnection at all voltage levels. This can pose challenges when opening circuit breakers to create restoration paths for Black Start. Moreover, primary substations (33/11kV) share the same interconnected network at lower voltages (11kV and LV) in normal operation. Splitting the 11kV and LV meshed network in a primary group prior to the Black Start may be required to ensure that the size of the block loads is reduced to the capacity of primary transformers, thus reducing the impact on the DER. However, confirmation of its practicality requires further detailed analysis for each specific primary group, hence the amber risk level considered.

3.8 Distribution network – resilience

3.8.1 Introduction

Following a Black Start, before the DER can be restarted to energise the network, it is necessary to ensure that all relevant substations are safe to energise. This means that essential elements such as the protection, control and SCADA systems are available, along with the required operability of the plant e.g. supplies available for transformer tap change motors. The ability of these services to be maintained is what is referred to as the resilience of the substations. A key measurement of this is the time duration after a Black Start is initiated after which it would not be safe to energise the network, or the required operability would not be available.

A baseline requirement has typically been for strategic distribution and transmission substations to be designed with approximately 72 hours' resilience. However, with Black Start now becoming a major consideration, resilience of up to 168 hours (seven days) may be more commonly required as per the current guidance for strategically important sites in ENA ER G91. This section of the report highlights the factors affecting resilience at the major nodes of the network, and how the resilience may be enhanced.

Consideration of the resilience of the telecommunications and control network is out of the scope of this document. This will be covered by the Organisational Systems and Telecoms workstream of the Distributed Restart project.

3.8.2 Grid supply point/grid substation

This section refers to the following transformer substations:

- 132/11kV (SPD)
- 275/33kV (SPD)
- 132/33kV (SPD & SPM).

These substations typically contain two identical transformers and a 33kV switchboard controlling multiple 33kV circuits to the distribution network.

3.8.2.1 Resilience issues

The key systems at a grid substation required for safe operation are:

- protection relays (supplied from 110V or 48V battery)
- SCADA (supplied from 48V battery)
- circuit breaker closing (close coil supplied from 110V battery, LV motor for spring charging or 110V DC solenoid closing)
- circuit breaker opening (trip coil supplied from 110V battery)
- transformer tap change motor (supplied from 415V LV supply).

3.8.2.2 Batteries

Utilisation

A grid substation would typically have a 110V battery (see figure 3.13), used for tripping circuit breakers, and a 48V battery, used to power the SCADA system. (Strategically important substations would have two 110V batteries). The protection relays would also be powered from the 110V or 48V battery (except the older electro-mechanical types which do not require a supply). Some switchgear would also use the 110V battery for closing circuit breakers (solenoid closing), but this is more commonly done by charging springs (either manually or by a 415V motor).

Figure 3.13

Example 110V grid battery

Resilience

The battery capacity is determined taking into account the likely deterioration in battery capacity over its life and the standing load. They should allow for a limited number of circuit breaker open and closing operations. The current guidance in ENA G91[2] is that batteries have resilience of 72 hours, and up to 168 hours for strategic sites. Some existing batteries may only be resilient for 18 hours–24 hours.

3.8.2.3 LV supply (415V)

The LV supply at a grid substation is normally derived from the earthing transformers on the grid transformers. Thus, when the transformers are not energised, the LV supply will not be available.

A grid substation may have a standby diesel generator to supply the LV AC essential services board (this is dependent on the DNO policy and may depend on the criticality of the substation). Typically the generator will have fuel for 72 hours. This will keep the batteries charged, and may also be used for motive power for circuit breakers, spring charging motors on circuit breakers, or transformer tap change motors.

[2] Engineering Recommendation G91 Substation Black Start Resilience.

3.8.2.4 Enhancing resilience

The resilience of a grid substation could be increased by:

i) additional battery capacity

ii) installing standby generation

iii) split battery scheme (two separate batteries are provided)

iv) total DC demand disconnection scheme (SCADA control to disconnect DC protection demand until required)

v) partial DC demand disconnection scheme.

3.8.3 33kV and 11kV networks

Resilience is an issue for 33kV and 11kV networks where they are of the meshed type. That is, the circuits operate as closed rings, between the main infeed substations, and may have multiple intermediate substations. This is prevalent in SPM where the 33kV and 11kV networks are mostly meshed, but not typical for other DNOs. Figure 3.14 contains a schematic of a section of the SPM meshed 33kV network showing the intermediate 33kV substations. (These typically also include a primary transformer, see section 3.8.4.)

The key systems at the intermediate network substations (33kV or 11kV) for safe operation are:

- protection (supplied from 48V battery)
- SCADA (supplied from 48V battery)
- circuit breaker closing (close coil supplied from 110V battery, LV motor for spring charging or 110V DC solenoid closing)
- circuit breaker opening (trip coil supplied from 110V battery).

3.8.3.2 Batteries

Utilisation

Figure 3.15 shows a typical SPM 33kV Ring Main Unit (RMU) which would be used as an intermediate substation. The RMU contains a circuit breaker and two isolators, one of which is used to connect to a primary (33/11kV) transformer. At each RMU, a unit protection relay is installed which is supplied by a 48V battery which is charged from the local 415V network supply. Thus, for a Black Start scenario, the resilience of the substation would be dependent upon the batteries (up to 72 hours at best). Remote control of the circuit breaker in a RMU is dependent upon the 48V battery supply for the SCADA (not all RMUs have SCADA installed).

3.8.3.3 LV supply 415V

Motive power

A local 415V supply is required to operate the motor to rack the 33kV circuit breaker up and down. This is unlikely to be required due to Black Start, but if so, this functionality would not be available.

Circuit breaker closing

A circuit breaker requires the closing springs to be in the charged state in order to close the circuit breaker. In older type switchgear (e.g a 33kV RMU), this would have to be done manually (depressing a lever). The springs on such circuit breakers are normally left charged which allows one closing action before a site visit is required. Other units require a 415V supply to operate a spring charging motor (for network substations this is derived from the distribution network). On some switchgear, a solenoid is used for closing, supplied from the substation batteries, thus eliminating the need for a 415V supply.

Figure 3.14

SPM 33kV meshed network schematic

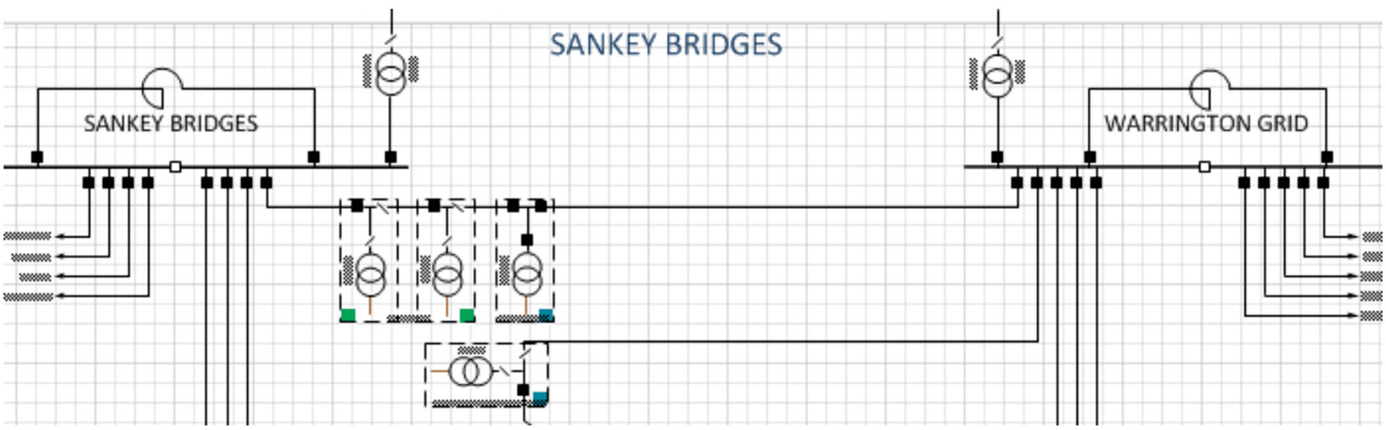


Figure 3.15
RMU

3.8.3.4 Enhancing resilience

The above resilience issues are common to 33kV and 11kV intermediate substations. The resilience of the SCADA and protection could be enhanced by additional battery capacity or SCADA controlled demand disconnection schemes when not in use.

For spring charging and motive power to the circuit breakers (where required), it would not be viable to install standby generation at all intermediate substations, but perhaps at critical nodes only.

3.8.4 Primary (33/11kV) substations

A primary substation typically contains one or two 33/11kV transformers with an 11kV switchboard supplying multiple 11kV feeder circuits. In SPM, a primary transformer typically forms part of a 33kV network substation.

3.8.4.1 Resilience issues

The key systems required for safe operation are as per a grid substation (section 3.8.2), that is:

- protection (supplied from 110V or 48V battery)
- SCADA (supplied from 48V battery)
- circuit breaker closing (close coil supplied from 110V battery, LV motor for spring charging or 110V DC solenoid closing)
- circuit breaker opening (trip coil supplied from 110V battery)
- transformer tap change motor (supplied from 415V LV supply).

The resilience issues, and mitigation measures, are as per a grid substation (see 3.8.2). The main difference is that it is likely to be viable to install standby generation only at critical primary substations due to the volume of sites. This would mean that if a primary transformer was energised without the 11kV network connected, the tap changer motor would not operate due to the 415V supply being from the local distribution network. This may result in voltages on the transformer 11kV terminals out with acceptable limits.

3.8.5 Secondary (11,000/415V) substations

3.8.5.1 Resilience issues

Resilience is typically only an issue for meshed 11kV networks where a secondary intermediate substation would have 30V batteries to supply the 11kV unit protection relays. The existing resilience of these batteries is likely to be variable up to 72 hours.

3.8.6 Network resilience issues register and conclusions

Table 3.20 shows the addition to the issues register related to the network resilience issues.

Table 3.20

Network resilience issues register

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
RES	RES 1	The protection and SCADA at substations is dependent upon batteries which have variable resiliences from ~18 hours to 72 hours without a charging supply.	A substation may not be safe to energise at the required time after a Black Start if the protection and SCADA was not available.	Ensure that the batteries have adequate resilience at the key substations, or standby generation is installed to maintain the battery charging.	
RES	RES 2	It may only be possible to close a circuit breaker at a substation once after which there will be no LV supply to recharge the closing springs.	A circuit breaker is closed as part of a power island restoration plan. If the power island collapses, or the circuit breaker has to be opened to shed load, it may not be able to be reclosed.	Install standby generation to provide a LV supply to recharge the springs. Plan the restoration strategy so that the substation providing the LV supply to the main substation is energised first.	
RES	RES 3	If there is no LV supply at a transformer substation the transformer tap change motor will not operate.	When a transformer is energised, its LV voltage may be out with satisfactory limits and if high voltage may cause damage to equipment.	Energise the transformer with its load connected to avoid high open circuit 11kV voltages. Install stanby generation at strategic substations for the tap chage motors. Ensure when a transformer is energised it is energised with the load connected that provides the LV supply to the transformer substation.	

- Resilience is required at substations such that they are safe, and operable, to energise following a period of no supply during a Black Start.
- While 72 hours is a typical historical resilience design standard, existing substations may fall significantly short of this, primarily due to deteriorated batteries on the network, and up to 168 hours may be required in the future for Black Start requirements.
- Resilience at substations is dependent on the batteries and/or LV supplies for essential services such as protection, SCADA, opening and closing circuit breakers, charging batteries, charging circuit breaker closing springs and operating transformer tap change motors.
- Resilience may be increased by installing additional battery capacity, limiting the load on batteries when the substation is de-energised or installing standby generators for a 415V supply.
- The resilience to be installed at a substation will depend on factors such as its criticality, required Black Start resilience requirements, and the cost and practicality issues.

Chapter 4

Initial proposals for functional and testing requirements

Initial proposals for functional and testing requirements

4.1 Introduction

This section will give an understanding of the existing local joint restoration plans (LJRP), review the existing functional requirements for Black Start stations and their relevant testing protocol such that a comparison and proposal can be made for how these should be altered to facilitate the entry of DER providers into this service.

4.2 The role of a local joint restoration plan

In order to be a Black Start station, plant must be capable of enacting a LJRP if a Black Start event is declared by National Grid ESO. LJRP and procedures are agreed between National Grid ESO and Black Start stations on the formation of power islands. In each plan will be information regarding the scheduled activities and communications protocols that will be exercised in the event of a total or partial shutdown.

Each Black Start Station should have an LJRP agreed with National Grid ESO, and each is responsible for the creation and development of a power island. Agreement with the local Transmission Owner (TO) is also required, and these LJRPs may also cover more than one Black Start station. The different power islands will eventually be able to connect to adjacent power islands, ultimately achieving complete system restoration through this.

Typically, an LJRP will include, as a minimum, the following information:

- the part of the NETS and/or local Distribution System to be energised by the Black Start station and the methods by which this will be achieved;
- how the block loading of the Black Start station is to be achieved;
- manner of operation during islanded conditions;
- telephone numbers of all parties concerned and all other pertinent information; and
- the time periods required for the restoration of such necessary consumables.

The Grid Code stipulates the operation of an LJRP in seven main steps in OC9.4.7.6 (a) – (g), which can be summarised as follows:

(a) once in the process of executing an LJRP, National Grid ESO can issue instructions to override those in a LJRP

(b) a Black Start station will be given the instruction to start up (from shutdown) by National Grid ESO as per the provisions of their LJRP

(c) National Grid ESO will advise the relevant network operator of the requirement to make itself ready to carry out actions in the LJRP and operate in accordance with the provisions of the LJRP

(d) National Grid ESO will ensure that switching carried out on the transmission system and other actions are performed as set out in the LJRP

(e) the Black Start station will notify National Grid ESO of its readiness to accept load, and National Grid ESO will then coordinate the block loading of demand and the creation of a power island, instructing on output levels

(f) execution of the LJRP will be terminated by National Grid ESO prior to connecting the power island to other power islands. It will also be terminated in the case of connection of the power island to another user system or network operator, or when synchronising gensets at other power stations

(g) in Scotland, some gensets which are not Black Start stations but are included in a LJRP will operate in accordance with the LJRP for the duration.

It should be noted that no offshore TO is presently included in any LJRP to avoid the situation of an onshore TO controlling the assets of an offshore TO.

4.3 Existing functional requirements

The existing Black Start functional requirements for providers in GB are outlined by National Grid ESO, who are responsible for ensuring there are contingency provisions in place in the event of a total or partial shutdown of the NETS.

The existing technical requirements for a Black Start Station fall into three categories:

- the ability to start up independent of external supplies;
- the ability to energise part of the transmission network; and
- the ability to block load local demand.

The key technical capabilities required for current providers of Black Start services are summarised in table 4.1. (Source: NGET Black Start Strategy[1]).

[1] NGET Black Start Strategy https://www.nationalgrideso.com/sites/eso/files/documents/Black%20Start%20Strategy%20Version%202%20April%202018.pdf

Table 4.1
Key technical generator capabilities required for Black Start

Technical capability required	Why is this required?
High availability of Black Start capability on both the main and auxiliary generating plant (typically 90 per cent).	Whilst a system shutdown is low likelihood, it could happen at any time.
Ability to start up the main generating plant (at least one unit/module) of the station from shutdown without the use of external power supplies.	In the event of a Black Start, the transmission system will not be energised so a provider will need to be able to start up independently and start to energise the system.
Ready to energise part of the NETS or, if appropriate, the Electricity Distribution System within two hours of instruction from NGESO.	The sooner stations can start energising the network, the sooner total restoration can be achieved. Establishing the initial status, preparation and switching will need to also take place between NGESO, TO and DNO, so two hours is considered a realistic timescale for all parties to be coordinated.
The reactive capability to energise the immediate Transmission Network/Distribution System(s). This capability will depend on the local system configuration, but generating plant connected at 400kV or 275kV with a capability of at least 100 MVAr leading (as measured at the commercial interface) should almost invariably meet this requirement. The generator must also be capable of withstanding the magnetic inrush and transient voltages associated with this energisation.	Energising the local system is one of the first steps in restoring the network. The reactive capability must be sufficient to energise a nearby substation.
The capability to accept instantaneous loading of demand blocks, preferably in the range 35 MW to 50 MW, and controlling frequency and voltage levels within acceptable limits during the block loading process (under these conditions, frequency can be within the range 47.5 Hz–52 Hz).	The MW size of demand blocks being restored will be determined by the ability to separate the DNO system into separate areas. The size of these demand blocks will have some uncertainty.
The ability to provide at least three sequential Black Starts, to allow for possible tripping of the Transmission Network/ Distribution System(s) during the re-instatement period or trips during the station's starting sequence itself.	During system restoration, the system will be less stable than under normal operation so the likelihood of faults/trips is increased.
Facilities to ensure that all generating units can be safely shut down without the need for external supplies, and can be maintained in a state of readiness for subsequent start-ups.	It may be that multiple attempts are required to deliver restoration.
Back-up fuel supplies (e.g. distillate fuel), if appropriate, to enable the provider to run for a minimum duration, ideally in the range three to seven days, following a Black Start instruction.	Alternative fuel sources will provide increased resilience in the restoration.
Resilience of supply, Black Start service – deliver contracted service for minimum time of 10 hours.	It may take up to 10 hours for restoration to proceed to a point where other generators are online and operating in a stable manner such that the Black Start station is then not required.
Resilience of supply, Black Start auxiliary units – run continuously at rated output for a minimum of three days.	It may be up to 3 days before the Black Start station is called upon to provide the service so its auxiliary units must be capable of maintaining it in a state of readiness for that time.
Ability to control voltage level within acceptable limits during energisation/block loading (±10 per cent).	Black Start service providers will need to maintain voltage (within limits) when creating, maintaining and expanding a power island.
Ability to manage frequency level when block loading (47.5 Hz–52 Hz).	Black Start service providers will need to maintain frequency within limits when creating, maintaining and expanding a power island.

Previously, and indeed presently, one large provider is typically capable of delivering all of these features, but these requirements could be met by a combination of providers in some situations. The arrangement must be considered on a case by case basis, as not all provider combinations may be capable of providing the necessary services to execute a Black Start and perform a restoration.

In future, these requirements will more often need to be met by a combination of providers, as it is very unlikely that any single non-traditional technology type or DER site will have the capability to provide all these services.

4.4 Procurement of technical capability

National Grid ESO is now trialling a more competitive procurement approach for Black Start services, delivering on what was presented in their Black Start Strategy, Procurement Methodology[2], and Restoration Roadmap[3]. The trial for services covers two zones, provisionally in the South West and Midlands, for service commencement in April 2022. The service requirements requested by National Grid ESO can be seen in table 4.2. Many service requirements are the same as the existing ones, however the block loading MW capability has reduced by 15 MW. Crucially, this procurement event allows a number of parties to form a partnership or consortium to meet the outlined technical requirements, where one single provider cannot meet all of these on its own.

Table 4.2

Requirements for Black Start ancillary services

Category	Requirement		Definition
	Existing	Trial	
Time to connect	≤ 2 h	≤ 2 h	Time taken to start up the Black Start plant from shutdown without the use of external power supplies, and to energise part of the network, within two hours of receiving an instruction from the electricity system operator (ESO).
Service availability	≥ 90%	≥ 90%	The ability to deliver the contracted Black Start service over 90 per cent of a year. Note: It is the responsibility of the provider to demonstrate its service availability. By submitting a tender, the provider commits to ensuring availability at least 90 per cent of each year of the service.
Voltage control	Existent	Existent	Ability to control voltage level within acceptable limits during energisation/block loading (±10 per cent).
Frequency control	Existent	Existent	Ability to manage frequency level when block loading (47.5 Hz–52 Hz).

[2] NGET Black Start Procurement Methodology https://www.nationalgrideso.com/sites/eso/files/documents/Black%20Start%20Procurement%20Methodology%20Issue%202%20April%202018_0.pdf

[3] NGET Restoration Product Roadmap https://www.nationalgrideso.com/sites/eso/files/documents/National%20Grid%20SO%20Product%20Roadmap%20for%20Restoration.pdf

Table 4.2 continued

Requirements for Black Start ancillary services

Category	Requirement		Definition
	Existing	Trial	
Resilience of supply, Black Start service		≥ 10 h	When instructed to Black Start, the minimum time the provider will deliver the contracted service.
Resilience of supply, Black Start auxiliary unit(s)	≥ 72 h	≥ 72 h	Run continuously at rated output for a minimum of three days.
Block Loading Size	≥ 35 MW	≥ 20 MW	Capability to accept instantaneous loading of demand blocks.
Reactive Capability	≥ 100 MVAr Leading	≥ 100 MVAr Leading	Ability to energise part of the network (MVAr>0, MW=0).
Sequential Start-ups	≥ 3	≥ 3	Ability to perform at least three sequential start-ups.

Given the trends in decentralisation of generation, in future there will be a larger number of smaller generators likely to be procured to provide Black Start services. As such, opportunities for service providers to form a collective to meet the necessary requirement will almost certainly be necessary, and there may also be a case for giving concessions if a potential provider has a limitation on one of the technical requirements (where network or DNO factors may accommodate a reduced capability) but can meet the others.

4.4.1 Requirement proposals for DERs

The existing requirements have been built up around, and are suitable for, large conventional power stations providing most, if not all, Black Start services. While the majority of the services that will be required in future remain the same (e.g. frequency control, block loading) the Grid Code and associated procurement processes will all have to be adapted to accommodate the changing generation landscape and the complexities this introduces when planning and executing a restoration.

The functional requirements for Black Start may retain the main principles that the present requirements outline but, for example, some specific quantities may be modified to reflect the capabilities of smaller and more distributed generators and other energy resources. Table 4.3 highlights how this might be carried out.

Table 4.3
Examples of proposed changes to technical specifications for Black Start

Existing Black Start requirement	Retained principle and proposed changes
Ability to start up the main generating plant (at least one unit/module) of the station from shutdown without the use of external power supplies.	Desired but not mandatory for all Black Start Stations. Onus would be on National Grid ESO to ensure enough Stations had self-start capability within a power island area.
Ready to energise part of the NETS or, if appropriate, the Electricity Distribution System within two hours of instruction from National Grid.	More suitable timeframe could be appropriate given capabilities of fast acting technologies.
The reactive capability to energise the immediate Transmission Network/Distribution System(s). This capability will depend on the local system configuration, but generating plant connected at 400kV or 275kV with a capability of at least 100 MVAr leading (as measured at the commercial interface) should almost invariably meet this requirement. The generator must also be capable of withstanding the magnetic inrush and transient voltages associated with this energisation.	To make provisions for lower voltage levels and lower levels of reactive power. Not feasible to dictate a MVAr value for a single generator as this will vary considerably. Withstand capability requirements should remain unchanged.
The capability to accept instantaneous loading of demand blocks, preferably in the range 35 MW–50 MW, and controlling frequency and voltage levels within acceptable limits during the block loading process (under these conditions, frequency can be within the range 47.5 Hz –52 Hz).	Smaller (less MW) blocks of demand in accordance with smaller distribution power island sizes. Ability to control frequency and voltage should remain unchanged or be provided by an external controller connected via secure Black Start communications link.
Resilience of supply, Black Start service – deliver contracted service for minimum time of ten hours.	May take longer to establish a DER-based capability suitable to re-energise the transmission network and restart other generation.
Resilience of supply, Black Start auxiliary units – run continuously at rated output for a minimum of three days.	The goal is to accelerate the restoration process so there may be no desire to extend this time.
Ability to control voltage level within acceptable limits during energisation/block loading (±10 per cent).	Requirement may remain unchanged.
Ability to manage frequency level when block loading (47.5 Hz – 52 Hz).	Requirement may remain unchanged.

The 2017 *System Operability Framework (SOF)* proposed some indicative values for the functional requirements regarding availability and reliability that could be set for smaller and distribution network-connected Black Start resources, as shown in table 4.4.

Table 4.4

Preliminary proposals for Black Start availability and reliability requirements

Technical capability for Black Start providers	Existing at 400/275kV	Requirement at 132kV	Requirement at 33kV	Requirement at 11kV
Availability of Black Start capability on main and auxiliary plant	>90%	>90%	>90%	>90%
Number of times able to start (at least one unit/module) without external power supplies	Three	Three	Three	Three
Facilities to ensure all plant can be shut down safely without external supplies	Yes	Yes	Yes	Yes
Time to be ready for network energisation following instruction	Two hours	Two hours	Two hours	Two hours
Reactive range to energise the immediate network	Typically 100 Mvar absorbing	Approx. 50 Mvar absorbing	Approx. 5 Mvar absorbing	Approx. 0.5 Mvar absorbing
Ability to withstand inrush currents and transient voltages associated with network energisation	Yes	Yes	Yes	Yes
Demand block loading capability while controlling frequency and voltage within limits (47.5 Hz–52 Hz for frequency and 0.95 to 1.05 pu for voltage)	35 MW–50 MW	35 MW–50 MW (Energise 33kV circuits from a GSP)	10 MW–20 MW (Energise 33/11kV Primary)	0.5 MW–1 MW (Energise 11/0.4kV Secondary)
Time expected to run following a Black Start instruction, and therefore back-up fuel supplies to be available	Ideally three–seven days	Ideally three–seven days	Ideally three–seven days	Ideally three–seven days

These functional requirements will be explored more fully in the next stage of the project, using the case studies and broader stakeholder engagement, to determine what is necessary and practical. Moreover, it may be that some of the functional requirements are placed on the distribution island as a whole, and not on individual DER. For example, a microgrid controller, controlling multiple resources such as DER and load banks, may be able to provide the required demand block load capability with a relatively small DER capability. The functional requirements will ultimately be reflected in the testing requirements as part of an overall approach to assurance on Black Start capability.

4.5 Black Start testing procedures

At this stage of the project, rather than be prescriptive around testing arrangements for distributed restoration without knowing what the final solution, or range of solutions, this report focuses on the different options available. The starting point is to assume that the overall approach will be similar to the current approach with an assurance framework that includes a range of tests, assurance visits and desktop exercises or similar. However, there are some key differences with the DER-based approach.

4.5.1 Current process

The current process for ensuring Black Start readiness looks at a wide range of NGESO requirements. Whilst it is recognised that all of these aspects will continue to be important for Black Start from DER, the focus here is on the "delivery of generator testing programmes". The NGESO Standard Operating Procedure (SOP) entitled "Black Start Readiness" details what is required for the organisation and planning of Black Start assurance activities including Black Start tests, assurance visits and desktop exercises and the relevant sections are included in Appendix K – existing test procedures. The remainder of this section details those procedures in the light of a DER driven solution although it is recognised a hybrid of the two will be required for a combined approach to restoration.

4.5.2 Differences for Distributed ReStart

At this stage of the project, rather than be prescriptive around testing arrangements for distributed restoration without knowing what the final solution, or range of solutions, looks like, this report focuses on the different options available. The starting point is to assume that the overall approach will be similar to the current approach with an assurance framework that includes a range of tests, assurance visits and desktop exercises or similar. However, there are some key differences with the DER-based approach.

4.5.2.1 Many more parties involved

With a distributed restoration strategy, multiple DER will be required to achieve a capability equivalent to a single large service provider. This means that each LJRP may involve multiple DER parties, or there may be many more LJRPs. Sticking with the current methods involving detailed assurance plans and witness tests on all providers, all coordinated and led by NGESO, would require huge resources. As with other forms of audit and quality assurance, there is still expectation of some independence from the providers themselves if a consistent level of assurance is expected.

Large scale testing of multiple distribution power islands will prove disruptive and require large numbers of outages often at a voltage level where single circuit security risk occurs. To disrupt supplies or even reduce security on a large scale may be considered but this is unlikely to be accepted by the regulator, government and other stakeholders as an acceptable solution.

4.5.2.2 Greater role for DNOs

The DNOs will have a larger role to play, going beyond existing involvement in assurance activities and desktop exercises. The current approach to testing normally involves NGESO, the Black Start provider and the relevant TO (although some tests do involve more than one generator). Demand customers, and the DNO networks they are connected to, are normally protected from any Black Start testing. With a DER-based approach, the DNO will be involved in hosting and participating in tests. This has various implications for resources and the approach to testing.

4.5.2.3 Greater diversity in the types of resource

The existing approach to Black Start mainly involves large coal or gas fired power stations, pumped storage hydro, or (more recently) large HVDC links. For a DER-based approach, there may be much greater diversity in the types of generator, or storage, involved. Where there is a fuel type that has not provided restoration services previously it is recognised there may be some novel approach required or a technical limitation requiring special consideration. The capability of different technologies has been fully reviewed in the recently completed Network Innovation Allowance (NIA) project on "Black Start from Non-Traditional Generation Technologies".

Synchronous DER are the most similar to the majority of "traditional" Black Start service providers in that they are generally of rotating shaft type machines driven by turbines. Their testing requirements will be of a similar nature though it is recognised specific technical issues may have to be resolved prior to test procedures and test programmes being embarked upon. As discussed elsewhere in this report, these include any special earthing arrangements due to their position in the network, any special loading requirements associated with running up at no/low load, any specific frequency control necessary, and any special protections required. Nevertheless, the testing procedures and regimes for these machines may well prove similar to those currently used.

Converter connected DER will be subject to similar testing as synchronous DER, just as HVDC links must provide similar capabilities to large power stations. This includes both reactive power support and stabilising and balancing of generation and load. If acting as the anchor generator then the grid forming technology must be demonstrated.

4.5.2.4 Test multiple DER and the network together

Aside from the individual DER considerations, the Distributed ReStart concept means that multiple DER and the network they are connected to, plus essential demand, must be used in combination to deliver an effective Black Start service to the NETS. Testing therefore presents significant challenges in terms of integration of multiple resources with each other and the associated control and protection on the network, plus potential disruption to demand customers. A complete test of all these component parts may be necessary to demonstrate the full functionality of any DER-based restoration service and this represents a particular challenge for this novel approach.

Consistent with the security of supply standards and best-practice engineering design for a cost effective solution, distribution networks are generally less able, when compared to the transmission system, to accommodate outages without some disruption to customers. Conducting a test of DER-based restoration is likely to have an impact beyond those customers directly involved in the test. This may impose additional costs. The potential impact on demand customers is a significant difference from the current approach to Black Start testing and the willingness of customers to accept this must be considered carefully.

4.5.2.5 More complex outages

Establishing a DER power island then progressing to energise a transmission line would require coordination of outages on the distribution network and the target transmission circuit. This will require careful outage coordination between NGESO and potentially multiple DNOs/TOs. However, securing outages is becoming increasingly difficult as the networks become more heavily utilised with greater use of constraint management and related methods.

For any enduring hybrid approach to Black Start involving traditional transmission-led and distributed restoration methods it is expected the old and new testing arrangements would run concurrently. Consideration will also be given to coordination of the two approaches where practical to demonstrate successful power system synchronising. The least disruptive method of achieving this may well be to plan the transmission circuit outage in coordination with the return to service (RTS) of the distributed restoration outage. NGESO will continue to coordinate across the various differing functions of Black Start providers to ensure there are no conflicts associated with testing programmes.

4.5.2.6 New telecommunications and more sophisticated control systems

DER are often operated remotely and require site attendance to restart following any outage or shutdown, some requiring special intervention within given timescales. These limitations would apply equally for testing. Delivery of an effective Black Start service may require new telecommunications and control to be installed; this is being explored more fully in later works by the Organisational Systems and Telecoms workstream.

The testing of telecommunication systems and SCADA will need to be considered. Currently, the restoration process relies on OPTEL, an operational telephony system used throughout NGESO utilising dedicated fibres, which is highly resilient and supported for Black Start scenarios. OPTEL extends as far as transmission substations and to each individual DNO. It does not extend into the distribution network. Clearly, with a DER-based approach, any telecommunications, control and protection equipment will need to be tested to ensure Black Start readiness.

4.5.3 Distributed ReStart testing options

There are a number of options and opportunities to mitigate the additional risks and costs associated with a DER-based approach.

4.5.3.1 Testing when commissioning and during outages

It is recognised that commissioning of new DER is an opportunistic time to demonstrate Black Start restoration preparedness and this could exempt certain providers from initial rounds of Black Start testing if appropriate.

An approach to verifying capabilities based around an outage-led approach rather than a more intrusive testing-led approach could be investigated. This would need to be carefully considered by appropriate planning and coordination across DER, DNOs, TOs and NGESO but the underlying philosophy would be that whenever a suitable outage is planned for business as usual activities, the opportunity be taken, within agreed bounds, to demonstrate Black Start functionality.

4.5.3.2 Trip to island mode

The Black Start from DER concept includes the establishment of power islands at distribution level, similar in functionality to the microgrid concept that has been demonstrated in numerous projects around the world. One feature of many microgrids is the ability to transition seamlessly from grid-connected to island mode and back again. Many industrial facilities and some power stations have the capability to “trip to house load”, which means they can continue operating if they lose their grid connection. Part of the testing strategy for a DER-based approach could be to deliberately create distribution level power islands to demonstrate stable operation before returning to full grid connection, without any adverse impact on customers. This might be referred to as “trip to island mode” and be tested on a routine basis. The frequency of any routine testing of this feature will depend on many variables. Consideration will be given to whether the generation is supplying discrete demand, whether the same technology has been tested elsewhere on the network and other features that may yet come to light such as control and protection arrangements around this feature.

4.5.3.3 Statistical approach across all DNOs
Given the potentially large numbers of DER engaged to provide Black Start services, it may be useful to consider a statistical approach to testing. This would mean testing being done only on samples of the DER fleet rather than all of them. A more probabilistic approach may well complement any future Black Start standard. If a similar approach to restoration is being applied across the whole country, it may be reasonable to only require a sample size of actual operational testing to demonstrate assurance. If a statistical approach is agreed then a reasonable and workable level of assurance in terms of sample size and frequency will be needed. This sample size and frequency of testing does not, however, need to be fixed and provision should be made to allow for variations depending on DER type, organisational processes and previous results of success/failure rates, as well as any new solution requirements that may come to light.

This data would then be recorded across all distribution networks and trends/issues identified, which would then feed back into future test requirements and dictate frequency requirements of tests based on reliability figures seen. A pragmatic approach of demonstrating this particular process on a regular basis rather than an exhaustive demonstration of every instance if possible is recommended. Rolling DNO/TO participation would show a fair and thorough approach and aim to coordinate these tests with the least disruption and generator costs.

A probabilistic approach to testing may well fit the nature of DER better. Current testing methods have evolved over time and as the large combustion based generators that traditionally deliver the majority of Black Start provision have run less and less so their reliability has reduced. It is difficult to separate this low load factor effect from the natural aging effect on plant reliability seen in the traditional bath-tub curve. The load factor of any DER could be considered in deciding an assurance frequency or even necessity. It could be decided that a generator that frequently power cycles does not need to demonstrate its readiness in terms of start-up and ramping; this may relieve a large percentage of witnessed assurance tests.

4.5.3.4 Modelling and simulation
Given the challenges of real-life testing, and the potentially unacceptable impact on customers, there is scope for more extensive use of modelling and simulation, most likely performed in combination with other testing methods. Whether performed entirely in simulation software or with elements of hardware-in-the loop testing, suitably configured models would provide the means of conducting comprehensive testing on a routine basis. There are significant challenges in this approach and there would be costs in developing and maintaining the analysis tools and associated models. There would also be risks that the models do not fully capture all effects and therefore miss a critical aspect. This could be mitigated by using whatever real-life testing is performed to validate and extend the modelling approach.

As well as providing assurance of technical aspects of service delivery, a suitably configured modelling environment could also be used in training and to support assurance of organisational aspects in desktop exercises.

4.5.3.5 Third party or self-certification
The current approach to assurance involves NGESO performing the role of independent assessor. If the number of parties requiring assessment grows significantly, then there may be a role for third party assurance organisations, similar to the role played just now in other aspects of industry performance by quality assurance organisations. Ultimately, if DER-based restoration is so widespread and the numbers involved so large, then there may be scope for some types of self-certification.

In future, certain software solutions could well have self-diagnosing features and these might be taken as evidence of readiness following a suitable confidence gathering period. Thus, some types of testing may be automated and performed regularly, without human intervention and without disturbing normal operation.

4.5.4 Future work
Over the next year, in the design stage of the Distributed ReStart project, the testing requirements will be explored more fully and the proposed options assessed, taking account of stakeholder feedback. Given the critical nature of Black Start services, it is important that testing is sufficient to achieve the correct level of due diligence.

Chapter 5

The potential for roll-out of the method across GB

The potential for roll-out of the method across GB

5.1 Introduction

The whole Power Engineering and Trials scoping stage has been structured around ensuring the results and subsequent further work will be applicable across network areas throughout Great Britain. Preliminary analysis and future trial results consider the differences in technologies and topologies of these networks. This has been done through a combination of stakeholder consultations and a focus on their respective LTDS. Preliminary analysis shows that there are already suitable sites at 23 per cent of substations across the country, representing up to 9 GW of anchor generation with expectations of growth to up to 22 GW. Given that this is spread across all the current geographic Black Start zones and multiple DNO GSPs it could facilitate restoration under all the frameworks proposed in the viability section of this report. The following section provides evidence that further work will drive value across GB from a Black Start from DER service.

5.2 Potential of networks

5.2.1 Case studies

To ensure the enduring solution is representative of the varying network configurations and DER technologies available across GB, a broad range of studies will be progressed in latter project stages.

The Galloway and Dunbar case studies consider electrically local large power stations and DERs. This opens the opportunity to unlock value in areas with a high degree of conventional large generation which is not currently Black Start capable.

The Glenrothes and Portobello case study investigates energisation across interconnected GSPs at 33kV and the potential use of battery storage. This allows us to test co-located technologies and growing the power island at lower voltage levels before outward energisation.

The Chapelcross case study assesses rural networks with long distribution circuits, whereas the Bootle study focuses on an urban network which is predominantly cable based. Again, this increases potential for roll-out to more distribution network operating areas enhancing the potential for competition.

Dunbar has a very high proportion of wind relative to the anchor generator size and the Maentwrog GSP includes large distribution connected solar plant. This will enable testing and potential roll-out to network areas with high renewable levels.

Across all case studies, a variety of anchor generators are found including hydro, energy from waste, biomass, combined heat and power, diesel peaking plant and gas turbines.

This range of case studies is representative of the diversity found at DNO level with varying levels of installed capacity and network configurations covered.

5.2.2 Topologies

Within the two network licence areas of Scottish Power Energy Networks, there is a very different network design. The Scottish Power Distribution area is largely radial with interconnection present at 33kV and 132kV, whereas the Scottish Power Manweb zone is heavily meshed at all voltage levels. These represent the extremes present across GB networks, therefore viability across both network areas would encompass licence areas not specifically included in the trial or detailed studies. If a network area is found sufficiently different as to require further study, this could be considered during the design stage.

5.3 Technologies

The capability and challenges of networks section is driven by an analysis of the Long-Term Development Strategies of DNOs across GB, identifying key differences in earthing across networks which will need to be considered to ensure protection detects and clears faults appropriately during a DER-led restoration event. This shows that there are various earthing methods across all of the DNOs, however under the proposal of installation of an earthing transformer at the anchor generator, this could be standardised for the purpose of Black Start. Hence the only remaining technology which could be limiting to specific DNO areas is the capability of relays to accept additional settings for Black Start purposes.

5.3.1 Potential of DERs

An estimation of the potential for concept roll-out of Black Start from DER across all DNOs in GB has been made. Using the same essential case study technical criteria applied to the SPD and SPM areas, the number of equivalent case study locations across GB (and the associated capacity and types of DER) has been calculated. This assessment made use of the technical information published within respective DNO LTDS.

This section shall provide an initial estimation of the potential for concept roll-out of Black Start from DER across the remaining DNOs in GB. For this project, an assessment was made to identify all the potential Black Start network areas (case studies) in SPD and SPM, based on the essential case study criteria. In order to ascertain the number of equivalent case study locations across GB (and the associated capacity and types of DER), an assessment has been made of all the other DNOs' network data.

As part of this analysis, the number of potential grid substation locations which meet the technical criteria will be derived per DNO and the percentage given against the total number of grid substations within each DNO based on the connected DER.

For each DNO, the total MW of anchor generation and additional DER was calculated based on existing connected DER, and also with the contracted generation included.

5.3.2 Input data limitations

In discussing the input data used for this analysis, issues were encountered which may have a material effect on the results.

Under the LTDS generation categories, a proportion of DER in each DNO was classified as 'Other' or 'Mixed'. This totals ~10 GW across all DNOs including connected and contracted generation. For this assessment of other DNOs, it could not be determined if this DER would meet the Black Start case study criteria, and if so if it could be classified as anchor generation or additional DER. (For SPD and SPM, all individual DER classifications were identified). It follows that the 'Other' or 'Mixed' generation has been excluded from the assessment. This is likely to have resulted in a pessimistic view of the capacities and network areas suitable for Black Start from DER, particularly for the DNOs where this classification had a higher percentage of total generation.

Additionally, in a number of areas, information regarding the network layout was not included within the respective LTDS generation tables. This has led to certain sections of the network being analysed by the 132kV transmission infeed substation only.

5.4 Results

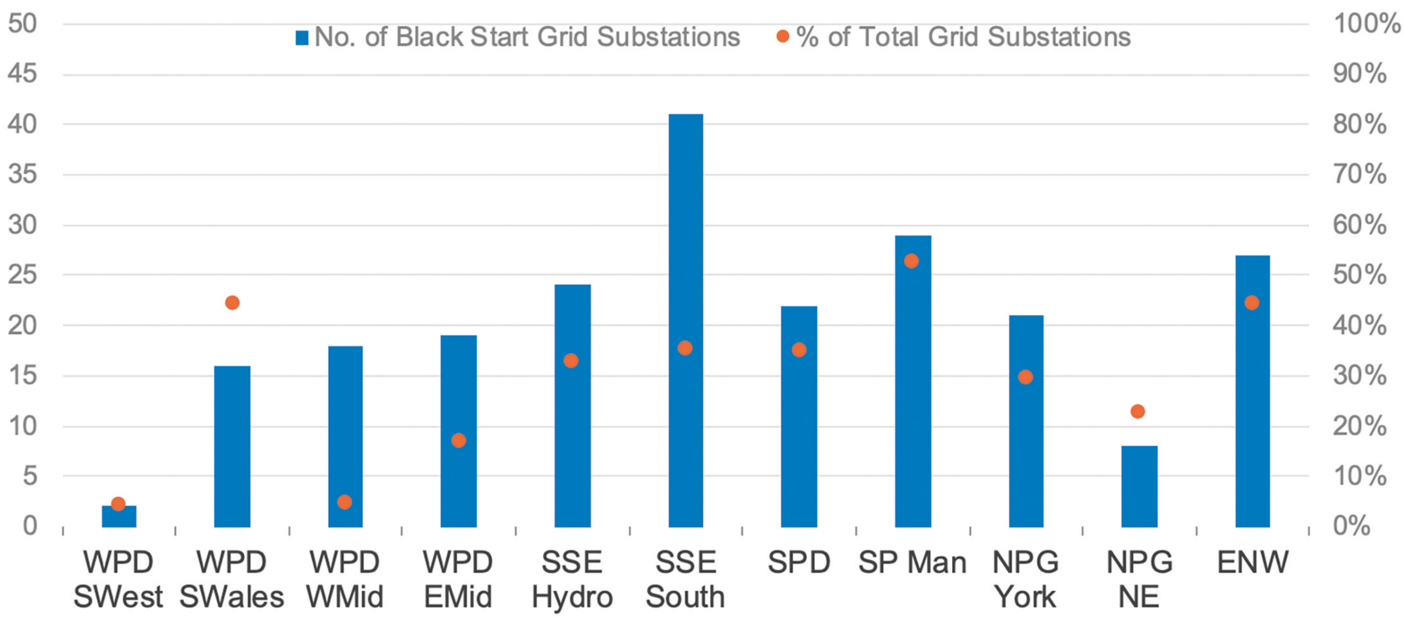
5.4.1 GB DNO potential Black Start grid substations

Across the total 1,103 GB grid substations considered as part of the analysis, 259 were found to meet the Black Start essential criteria based on connected DER. This is calculated as approximately 23 per cent of all grid substations. Figure 5.1 shows the number and percentage of grid substations, per DNO, based on the connected DER. As displayed, the highest percentages were found in SSE Southern (82 per cent) and SP Manweb (58 per cent) which would indicate a high proportion of synchronous generators within those regions with similar additional DER capacity available within those grid substations. (UKPN is not included as the data split was not available for the 33kV and 11kV substation voltage levels.)

When considering the amount of generation that could connect in the future, if 100 per cent of the current contracted generation was also taken into consideration, the total number of grid substations which meet the essential criteria would increase by 84, giving a total of 343 potential Black Start grid substation sites.

Figure 5.1

Grid substations in each DNO meeting Black Start essential criteria



5.4.2 GB DNO DER capacity

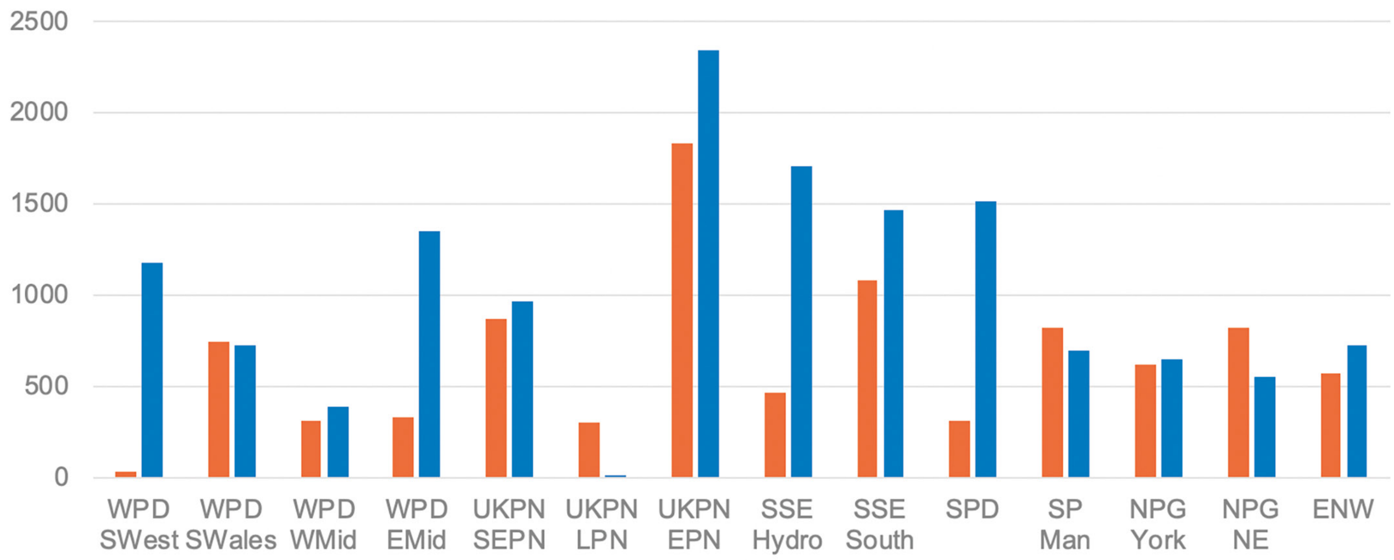
The total amount of anchor generation and additional DER in each DNO network area is shown graphically in figure 5.2.

It can be seen that there is a total of 9 GW of anchor generation and 14 GW of additional DER across all GB DNOs. It should be noted that this figure is potentially conservative given that it is based on connected DER only, and none of the DER in the 'Other/Mixed' classification has been included.

If 50 per cent of the current contracted generation is included, the total anchor generation would rise to 13 GW (6.5 GW at 33kV), and additional DER to 18 GW. If 100 per cent is used, the anchor generation increases to 17 GW (9 GW at 33kV), and additional DER 22 GW.

Figure 5.2

Capacity (MW) of anchor generation (orange), and additional DER generation (blue) per DNO area



5.4.3 Split of anchor generation and additional DER by connection voltage

Figure 5.3 shows the MW split of the anchor and additional DER based on connected voltage, and figure 5.4 based on the number of individual generation sites.

It can be seen that the capacity of anchor generation connected at 33kV and 132kV is similar at ~4 GW.

However, this consists of 249 generators connected at 33kV and only 34 generators connected at 132kV.

It can be seen from figure 5.4 that the vast majority of additional DER is connected at 33kV, with ~80 per cent of the total MW capacity, and also accounts for ~90 per cent of the total number of sites.

Figure 5.3

Anchor generation and additional DER MW split by connected voltage in MW

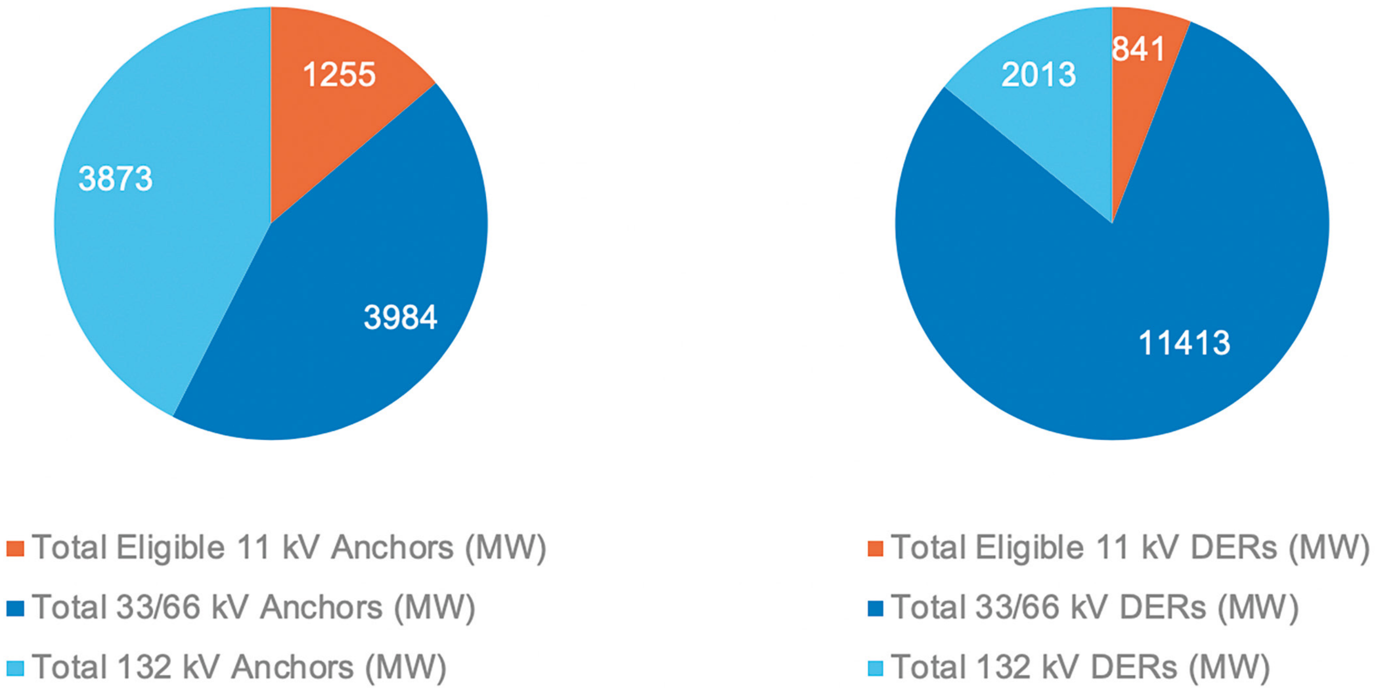
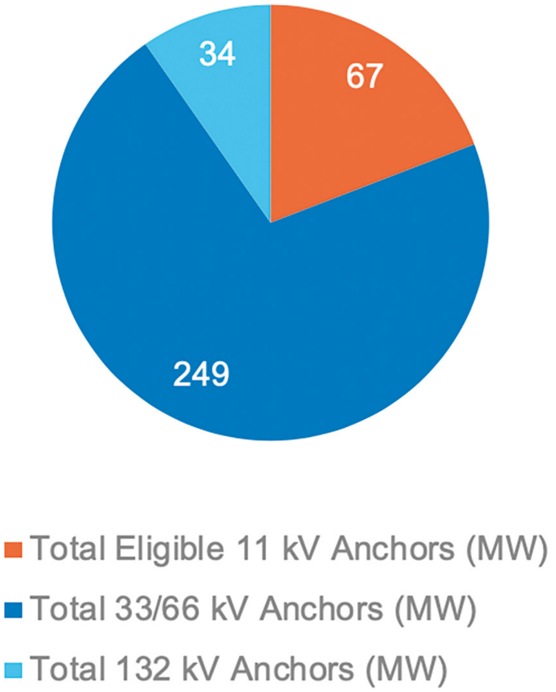
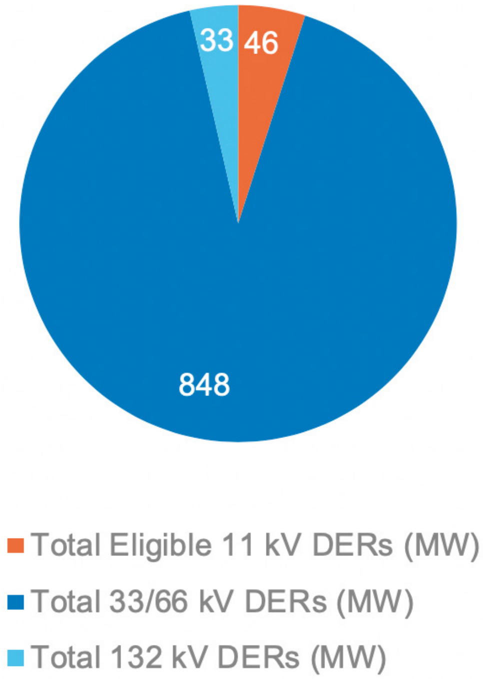


Figure 5.4
Anchor generation and additional DER MW split by connected voltage in number of generation sites





5.4.4 DER capacity conclusions

An estimation of the potential for concept roll-out of Black Start from DER across the remaining DNOs in GB has been made using the information published within respective DNO LTDS.

Analysis of the GB DNO networks indicates that there is ~9 GW of generation currently connected which meets the Black Start anchor generation criteria (as defined for the case studies). This consists of ~1 GW connected at 11kV, ~4 GW connected at 33kV and ~4 GW connected at 132kV. This would involve 350 individual generation sites, of which 249 (71 per cent) are connected at 33kV.

There is a total of ~14 GW of additional DER currently connected across the GB DNOs. The majority of this (~11 GW) is connected at 33kV which equates to 848 individual generation sites out of a total of 927 (91 per cent).

The total anchor generation and additional DER is connected across 259 distribution substations out of a total of 1,103 (24 per cent).

If 50 per cent of the current contracted generation is included, the total anchor generation would rise to 13 GW (6.5 GW at 33kV) and additional DER to 18 GW. If 100 per cent is used, the anchor generation increases to 17 GW (9 GW at 33kV) and additional DER to 22 GW.

Within the GB DNO LTDS data, there is ~10 GW of generation (connected and contracted) which is classified as 'other' or 'mixed'. As a result, it is has not been possible to determine the proportion of this generation which be applicable to Black Start, and if it is anchor generation or additional DER.

5.5 Possible investment

Given the viability assessment stage of this project, the cost-benefit analysis from the submission paper still represents the most current findings on net benefit to the consumer and likely costs to facilitate. However, this section uses the analysis conducted during this stage to identify equipment which may be required to facilitate Black Start from DER.

5.5.1 DERs

On most sites, installation of a resilient communications system will be required. In addition, auxiliary back-up generation will likely be required for essential services and to provide self-starting capability. A load bank or battery may also be required to enhance the block load capability of the DER.

If converter connected generation is included in restoration, changes to the control systems to allow for low fault operation may be required. Synchronous generators may require works to enable (or install) frequency and/or voltage control.

5.5.2 Networks

For networks, the most significant change to infrastructure is likely to be installation of an earthing transformer at the anchor generator 33kV substation to maintain safety standards and conform to current regulation. In addition, modifications to, or replacement of, existing protections may be required due to the low fault infeed from DERs. A control scheme (e.g. microgrid controllers) is also likely to be required to be installed in each distribution Black Start area to coordinate the DER and network plant operation to establish and maintain a power island.

5.6 Conclusion

This section of the report has focused on the applicability of the analysis across all other report sections to the rest of GB. It is believed that the degree of synchronous DER penetration is significant enough to support restoration under present installed capacities, meaning opportunities for improving restoration times, decarbonising and reducing costs are present across all Black Start zones.

Chapter 6

Conclusions

Conclusions

This report demonstrates that no critical technical issues have been identified which would result in Black Start from DER across GB being unviable.

All identified issues, and their possible solutions, are highlighted in the issues register (given in Appendix L – issues register). The detailed supporting analysis, based on ten case studies, focused on:

- A review of the capability of DERs, networks and associated control systems.
- The functional and testing requirements for DERs.
- An estimate of the potential roll-out of the service across GB. This has led us to draw the following conclusions and identify the major next steps in preparation for a continuation through to live trails.

6.1 Choice of studies

A range of case studies has been selected which are representative of generation mixes and networks across GB. Continuation with this list of case studies, spanning SP Distribution and SP Manweb zones, is recommended as the most appropriate means to test various technologies and ensure applicability across Great Britain. All of the case studies contain a synchronous generator to act as the anchor around which further generation can be connected.

Table 6.1
Selected case study conclusion

Case study progressed	Value to be unlocked
Galloway Region (SPD – Dumfries)	Test of a hydro generator to establish an island incorporating intermittent wind generation.
Glenrothes GSP (SPD – Central & Fife)	Test of combined heat power biomass to synchronise with an additional DER island with possible integration of battery storage.
Chapelcross GSP (SPD – Dumfries)	Test rural networks connected via long 33kV cable circuits.
Dunbar GSP (SPD – Edinburgh)	Potential to back energise to a conventional power station utilising energy from waste technology.
Meadowhead (SP Transmission – Ayrshire)	Utilise DERs connected at 11kV to energise up to 132kV.
Portobello GSP (SPD – Edinburgh)	Utilise an energy from waste generator to pick up demand and generation on the 11kV network.
Bootle Grid (SPM – Mersey)	Test urban networks capability.
Legacy (SPM – Wales)	Possibility of incorporating solar in a restoration.
Sankey Bridges (SPM – Cheshire)	Opportunity to energise to 132kV.
Maentwrog (SPM – Wales)	A fully renewable case study using a hydro station as an anchor but expanding to networks with solar and wind generation.

6.2 Viability

We have assessed the capability of DER to establish and grow a power island, the capability of networks to facilitate this and the challenges associated with operating a power island. This section highlights the major issues which have been identified across these categories.

6.2.1 DERs

Our analysis of DERs existing capabilities have led us to conclude that several changes to the existing infrastructure or processes may be required and lesser service provision than conventional plant, optioneering in the design stage will refine these to make suitable proposals.

The first substantial observation is the requirement of significantly smaller block loads in order to safely start a DER. It is believed this can be resolved by means of flexible demand. For the purpose of the trials, a load bank is the most desirable way of providing this.

Secondly, because DERs are not typically engaged in the frequency response and voltage control markets and are not subject to the code requirements of larger power stations, they do not always have a suitable control system for this essential part of network re-energisation. For existing units this may involve the installation or modification of control systems. However, innovation projects such as Power Potential which investigate unlocking this value are already underway and may prevent the need for bespoke installation.

When considering converter connected technologies, their requirement for a minimum fault level will require further work. The project concludes that alternative settings for low fault level operation may be possible, but this will be refined during the design stage.

Where a plant is not currently resilient to total loss of supplies, appropriate back-up will be required. Based upon stakeholder consultation, for many plants this will require retrospective installation.

Finally, some DERs may not be able to maintain their emissions limits during a Black Start process. Given that this is a highly unlikely event and does not represent typical operating conditions there may be scope to relax these, but further investigation will occur through the Procurement and Compliance workstream on this issue.

6.2.2 Control systems

The acceptable level of control engineer oversight during this form of event is identified as an issue for further investigation by the Organisational Systems and Telecoms workstream. However, exploration of existing microgrid controllers presented in this paper establishes that technology exists which can facilitate varying levels of automation.

Low inertia operation and the subsequent inability to provide small enough block loads in a power island is the key technical limitation. Microgrid controllers may be capable of providing the flexible demand discussed as a challenge in section 6.2.1.

6.2.3 Networks

Through the preliminary power system studies voltage profile, voltage step change, load flow, transformer energisation (inrush) and generator reactive capability were assessed. Some scenarios are highlighted where high and low voltages, excessive voltage dips or generator reactive capability issues may arise. However, these are not deemed to be critical issues with potential solutions being proposed.

Approximately 80 per cent of the SPM network is designed and operated as a meshed network with interconnection at all voltage levels. The splitting of this network, to establish a power island and provide small blocks of demand, is considered an issue requiring further analysis.

6.2.3.1 Protection and earthing

In a Black Start scenario, a 33kV power island will require a new method of earthing (the existing earthing transformers are connected to the grid transformers and will be disconnected from the system). The Electricity Safety, Quality and Continuity Regulations (ESQCR) require a network to be connected to earth, “at, or as near as is reasonably practicable to, the source of voltage”. A new 33kV earthing transformer will be required at most anchor generation installations. An alternative would be for all future potential anchor generators to have a switchable earth connection on their generator transformer 33kV winding.

The LV protection (mainly fuses) will operate as normal as long as the fault level at the grid substation 33kV busbar is at least ~30MVA. This should be achievable for most anchor DER connected to the 33kV network. However, there may be insufficient fault infeed for all existing 11kV, 33kV and 132kV protections to operate adequately. This can be overcome by having separate protection relay settings for Black Start. This may require additional relays, or relays to be changed with modern equivalents.

6.2.3.2 Network resilience

Before a Black Start, it is necessary to ensure all substations are safe to energise. This means that essential elements such as protection, control and SCADA are available. These systems are powered by batteries, with an LV supply for charging, which may also provide motive power for equipment such as tap change motors and circuit breaker spring charging where required. The current baseline requirement is that all core transmission and distribution substations are designed for 72 hours’ resilience. However, some existing substations may only be resilient for ~18 hours (the life of the batteries with no LV supply). For each power island, a survey will be required to ensure the required resilience at the key substations. This may be provided by additional battery capacity, battery demand disconnection schemes, and/or standby generation. DNO resilience and asset management policies may need to be amended to reflect the requirements of Black Start from DER in the future.

6.3 Testing and requirements

The System Operability Framework's proposed Black Start requirements at distribution voltage levels form the basis for the requirements which will be placed upon DERs for the final design. However, a refinement of these in conjunction with stakeholder input will be conducted during the subsequent design stage of the project. Consideration is also given to the possibility that some of the technical requirements (e.g. block load capability) are applied to the distribution island, with multiple resources being coordinated, as opposed to potentially onerous requirements being placed on a single DER.

Furthermore, given the labour intensity of existing Black Start testing regimes if applied to potentially numerous DER sites, it is likely that testing to ensure Black Start from DER readiness will be a hybrid solution of current practice and the test procedures developed during the desktop studies and live trials stages. Preliminary proposals on testing are made that include testing when commissioning and during outages; a statistical approach with sample-based testing; the greater use of modelling and simulation; the possible use of temporary operation in power island mode, which would demonstrate important aspects of DER and network capability without interrupting customer supplies; and the scope for third party involvement in testing.

6.4 Potential across GB

An estimation of the potential for concept roll-out of Black Start from DER across the remaining DNOs in GB has been made using the information published within the DNO long term development statements. It is believed that the degree of synchronous DER penetration is significant enough to support restoration under present installed capacities meaning opportunities for improving restoration times, decarbonising and reducing costs are present across all Black Start zones.

Analysis of the GB DNO networks indicates that there is ~9 GW of generation currently connected which meets the Black Start anchor generation criteria of which 4 GW is connected at 33kV. If 50 per cent of the current contracted generation proceeds, the 33kV anchor generation total will increase to 6.5 GW, rising to 9 GW should 100 per cent connect.

Table 6.2
Current connected and contracted anchor and additional DER across GB

Voltage level	Current connected anchor generation	Current contracted additional DER generation
11kV	1 GW	1 GW
33kV	4 GW	11 GW
132kV	4 GW	2 GW

Chapter 7

Next steps

Next steps

The next stage in the PET workstream is the design stage (from July 2019 till July 2020), when the detailed power engineering understanding of the DER and network capability will be developed, leading to firm proposals for the implementation of Black Start from DER. The foundation for this work will be the issues register (given in Appendix L – issues register) of this report. Each issue will be addressed, with a work package initiated with a view to identifying viable solutions.

At this stage of the project, the future power systems studies required have been considered, along with an update to the live trials strategy.

7.1 Future power system studies

In addition to issues listed above that need to be looked at in more detail, the following system studies would be undertaken in the design stage to simulate system restoration, where applicable:

- Voltage response and control studies, in order to investigate voltage response and voltage excursions within the power island during restoration. Reactive power capability of anchor generators in the power island will be further examined subsequent to network switching operation and block load picking up. Adjusting settings of anchor generator AVRs and tap positions of relevant transformers will be utilised to maintain voltage within acceptable limits. Impact of load characteristics (static vs motor) will be investigated.
- Frequency response and control studies, in order to investigate frequency response and excursions within the power island during restoration, especially after picking up block loads, connecting renewable DERs, and synchronizing with a neighbouring power island. Various governing modes, such as isochronous or constant frequency control (see section 3.2.2.2), will be examined for a single anchor generator to maintain system frequency within acceptable limits. Droop governing mode will be examined for multiple anchor generators to share the load picking up and participate in primary frequency control. Impact of load characteristics (static vs motor) will be investigated.
- Energisation studies for 132/33kV grid transformers and 400/132kV or 275/132kV Supergrid transformers where applicable in the case studies. The studies aim to assess the capability of an anchor generator (or a group of anchor generators) in a 33kV power island to energise a 132/33kV grid transformer or in a 132kV power island to energise a 400/132kV or a 275/132kV Supergrid transformer, identify challenges, and develop solutions that are technically feasible to allow the power island to be expanded to the 132kV and 400/275kV network. Voltage transients due to energisation of long distribution cables or long transmission circuits such as cable or OHL will be studied.
- Block loading capability studies, which are to investigate capability of anchor generators to pick up block loads. The amount of block loads that can be picked up will be assessed based on the given anchor generator type and size, its AVR and governor characteristics, and load demand characteristics. Special attention will be given to cold load picking up capability of the anchor generators due to very different dynamic characteristics of the cold load from the live supplied load characteristics (if available).
- Sychronisation impact studies, which will investigate the impact of synchronising two power islands while maintaining stable operation. Giving opportunity to explore the challenges of a synchronisation event, and identifying the technical requirements to permit this at distribution voltages.
- Load rejection studies, which will assess ability of the island power system to sustain both voltage and frequency within acceptable limits for Black Start and maintain stable operation subsequent to the loss of a block load, including the largest block load and trip-to-house load. The resultant extreme voltage and frequency may be used to verify settings of over-voltage relays and over-frequency relays for the anchor generator in system restoration.
- Transient stability studies, which will investigate the ability of the island system to maintain stability without pole slip between synchronous generators following a fault. System stability performance for various faults will be used to guide system restoration plans among several alternatives.
- Assessment of self-excitation for synchronous DERs. It is known that after energising a long overhead line circuit or a cable circuit fed by the synchronous anchor generator, there is the potential for self-excitation of the anchor generator. If the reactive charging power from the circuit to the anchor is more than reactive leading capability of the anchor generator, this self-excitation will result in uncontrolled voltage and potentially damage the anchor generator. Studies will be undertaken to assess network conditions under which the self-excitation of the anchor generator is likely to take place and to find solutions to prevent it happening.

Other areas like power quality issues such as unbalance due to long untransposed circuits, harmonic resonance, large motor starting and earthing protection considerations will be included. These above studies will be undertaken using power system dynamic simulations. Prior to the studies, dynamic models for the anchor generators and other relevant DERs (including their controllers) in the island system will be developed and validated in DIgSILENT PowerFactory. A special consideration will be given to those case studies which will be selected for the live trial phase.

In addition to the above dynamic studies, electromagnetic transient (EMT) studies will be undertaken to investigate the impact of Black Start from the DER on the island power system. The EMT studies will mainly focus on transient over-voltage assessment of switching or re-energising network components including transformers, overhead line, cables, shunt reactors, and shunt capacitors in the power island. Transient over-voltage will mainly cover temporary over-voltages and switching over-voltages. The EMT simulations will be performed in PSCAD.

7.2 Live trials update

Live trials are proposed in the final test phase of the project to verify the capability of DER and distribution networks to deliver the Black Start process.

7.2.1 Technology providers

In preparation for the live trials, meetings will continue to be held with technology providers to understand the equipment which may be hired to facilitate the trials and make them as realistic as possible. For example, as well as generators, it is possible to hire 415V/33,000v transformers, resistive and reactive programmable load banks and also batteries (in 1MW units).

7.2.2 Demand simulation

In order to make the live trials as realistic as possible, a key area will be the accurate simulation of demand. It is proposed to carry out a piece of work to model the different load profiles which may be expected to occur throughout GB at varying times of the year. This will also consider cold load pick up (CLPU). That is, the demand on a circuit may be higher than the forecast values depending on how long after a blackout situation it is re-energised. This may be due to factors such as a decrease in the diversity of household appliances over time. Based on these studies, realistic demand profiles will be programmed into the load banks for the trials.

7.2.3 Initial DER only trials

During the initial development stage of the project, it has become clear that there may be merit in staging the live trials. Instead of doing a single test at the end of the project, to test the DER and network together, it would be advantageous to test the DER on its own first to ensure correct operation. For example, for an anchor generator, it would be beneficial to ensure that all local issues have been addressed and it is capable of self-starting. Moreover, starting the generator with a load bank would allow live frequency response tests to be undertaken (by switching in additional loads) to accurately measure the governor response and determine the actual block load capability. This would allow the accuracy of system models to be assessed, and provide valuable information on the generators' capability to inform the design of the control system for the wider power island. Where practical, it is proposed that testing of specific DER may be undertaken in 2020.

Accuracy assurance statement

This progress report has been produced in agreement with the entire project hierarchy. The report has been written and reviewed by all project partners. The report has been approved by the Distributed ReStart Steering Committee and by Julian Leslie, the Project Sponsor. Every effort has been made to ensure all information in the report is true and accurate.

NGESO – Julian Leslie
Head of National Control
NGESO

Julian Leslie

SPEN – Eric Leavy
Head of Transmission Network
SPEN

Eric Leavy

TNEI – Charlotte Higgins
Networks & Innovation Team Lead
TNEI

Charlotte Higgins

Chapter 8

Appendices

Appendix A – case study descriptions

Case study 1 (SPD) Galloway Region

Glenlee, Glenluce and Newton Stewart GSPs are located in the Galloway region in south west Scotland and connected by a 132kV overhead line network. The 132kV network also extends to New Cumnock 275/132kV substation where more than 1,000 MW of renewable generation is contracted to connect by 2023. This network also leads to the load centres at Kilmarnock (~100 MW maximum demands) and the 132kV network to Hunterston nuclear power station. This case study will establish the requirements for the Glenlee hydro station (22 MW) to self-start, and back energise the 132kV network to connect the DER at Glenluce and Newton Stewart GSPs. From there, the potential to further energise the 132kV network to New Cumnock substation along with the potential to synchronise and create a stable power island with the significant transmission-connected renewable generation resources can be investigated.

Case study 2 (SPD) Glenrothes GSP Region

Glenrothes GSP is located in east-central Scotland. It has two 275/33kV 120MVA transformers and a maximum demand of ~38 MW. The 275kV supply comes from a double circuit tower line between SP Transmission (SPT) and Scottish Hydro Electric Transmission (SHET). The 33kV network interconnects to Redhouse and Westfield GSPs (maximum demands of ~41 MW and ~33 MW respectively). This case study will investigate the use of a synchronous generator (Markinch CHP Biomass plant) to energise the 33kV network, establish a stable power island, then energise the interconnecting 33kV network to Redhouse and Westfield GSPs, to connect additional DER and expand the energised area. It may also be feasible to self-start the Westfield Chicken Litter generator and examine how two power islands may be synchronised.

Case study 3 (SPD) Chapelcross GSP

Chapelcross GSP is located in Dumfries and Galloway in south west Scotland. The SPT assets include two 132/33kV 90MVA transformers that supply a SPD 13 panel 33kV switchboard supplying 8 primary substation (33/11kV) with total maximum demand ~45 MW. This case study will investigate the use of a biomass-powered synchronous generator as the anchor generator.

Stevens Croft Biomass connects via a 33kV underground cable (~25 km) directly to Chapelcross GSP. Minsca WF also connects to Chapelcross GSP via a 33kV underground cable (~17 km). Ewe Hill WF (12 MW) has a 33kV circuit to Middlebie 33kV switching station, which is supplied from Chapelcross 33kV GSP.

At adjacent Dumfries GSP, there is 87MW of DER currently connected to SPD's 33kV network, with a further 32 MW contracted (the maximum demand is ~60MW). Gretna 132kV substation has 39 MW of wind generation currently connected, with a further 130 MW contracted to connect. This case study will investigate the use of a synchronous generator, Stevens Croft Biomass, to energise its 33kV cable circuit to Chapelcross GSP along with the associated 33kV busbar. From this, the restoration of the 33kV network, along with the staged connection of demand at the primary (33/11kV) substations will be studied. In addition, we will investigate the feasibility of connecting the additional DER (~80 MW wind) and establishing a stable power island.

It may also be possible to back energise a 132/33kV grid transformer at Chapelcross, along with the potential to energise the associated 132kV network; including connecting additional demand/generation at Dumfries, additional generation at Gretna 132kV substation, and connecting to NGET's network at Harker 132kV substation. From Gretna, it may be feasible to extend the 132kV energisation to Hawick and Galashiels providing access to potentially hundreds moreMW of DER.

Case study 4 (SPD) Dunbar

Dunbar GSP is located in East Lothian (~30 miles east of Edinburgh) with two 132/33kV 60MVA transformers and a maximum demand of ~36 MW. It is supplied by two 132kV circuits (~8 miles) from Torness 132kV substation.

This case study will investigate the use of a synchronous generator (Dunbar Energy Recovery Facility) to energise the 33kV network, establish a power island and allow additional nonsynchronous DER to connect. The potential exists to back energise a 132/33kV transformer and energise the 132kV network to Torness nuclear power station. In addition, the Dunbar 33kV network interconnects to Cockenzie GSP (maximum demand ~46 MW), and will allow investigation of the potential for energising this remote 33kV network. Furthermore, the 33kV network energisation might be extended to Portobello, providing access to the 15 MW Millerhill energy from waste plant, more DER and demand in Edinburgh. This would establish a more substantial 33kV power island across a wide area.

Case study 5 (SPD) Meadowhead

Meadowhead, Saltcoats and Kilwinning are located on the west coast of Ayrshire, Scotland. The substations are connected by a 132kV overhead line network. The 132kV network also extends to Hunterston Farm 132kV, Hunterston 400/132kV and Kilmarnock South 400/275/132kV substations.

This case study will investigate the use of a transmission connected 11kV synchronous generator (Caledonian Paper CHP) to energise the 132kV network. This may then be used to energise the Saltcoats 132/33kV GSP. The Saltcoats network area has two grid substations, four 60 MVA grid transformers, eight primary substations and circa 100 MW of wind generation.

Case study 6 (SPD) Portobello

Portobello GSP is located in a coastal suburb of Edinburgh. It lies in eastern central Scotland, three miles to the east of Edinburgh city centre, facing the Firth of Forth. The SPT assets include two 275/33kV 120 MVA transformers that supply a SPD 16 panel 33kV switchboard supplying six primary substations (33/11kV) with total maximum demand ~98MW. This case study will investigate the use of a 15 MW waste incineration, synchronous generator to establish a power island at 33kV and connect 11kV synchronous DER to meet local load and energise the associated 33kV network.

Miller Hill Energy from Waste (EFW) (15MW) connects via Niddrie 33kV switching station via 2.4 km of 33kV underground cable.

Case study 7 (SPM) – Bootle

The 33kV group is supplied by a 132/33kV transformer at Bootle and a 132/33kV transformer at Litherland; with the 33kV network meshed.

This group has about 35MW of anchor generation (Strand Gate) and minimum load of about 13.17MVA. The minimum load is far less than anchor generation and thus may be suitable for bottom to top restoration in practice. There is an additional 18 MW of wind generation connected at 33kV.

Case study 8 (SPM) Legacy

This group has about 37 MW of anchor generation and minimum load of about 62.1 MVA. The generating stations are Kronospan (17 MW connected) and Cefyn Mawr (20 MW connected). There is an additional 125 MW of wind and solar generation connected at 33kV and about 28.2 MW of gas and solar generation connected at 11kV. This group is selected owing to the rural area it supplies where the loads are quite far away from anchor generation, but there is a lot of additional distributed generation that exceeds the demand. Further studies will help to understand similar groups and their impact during restoration.

Case study 9 (SPM) Sankey Bridges

Sankey Bridges 33kV
This group has about 54 MW of anchor generation and an almost equal amount of minimum load of about 54.2MVA. The generating stations are Warrington Power (16 MW in 2019), Arpley Landfill (18 MW connected) and Latchford Lane (20 MW connected). These three generators are fairly distributed across the Warrington and Sankey Bridges part of the group. Further studies can be carried out to check the voltage profile during restoration. This is a self-sufficient group as far as the minimum load is concerned and can be considered for Black Start in conjunction with Carrington 132kV generation.

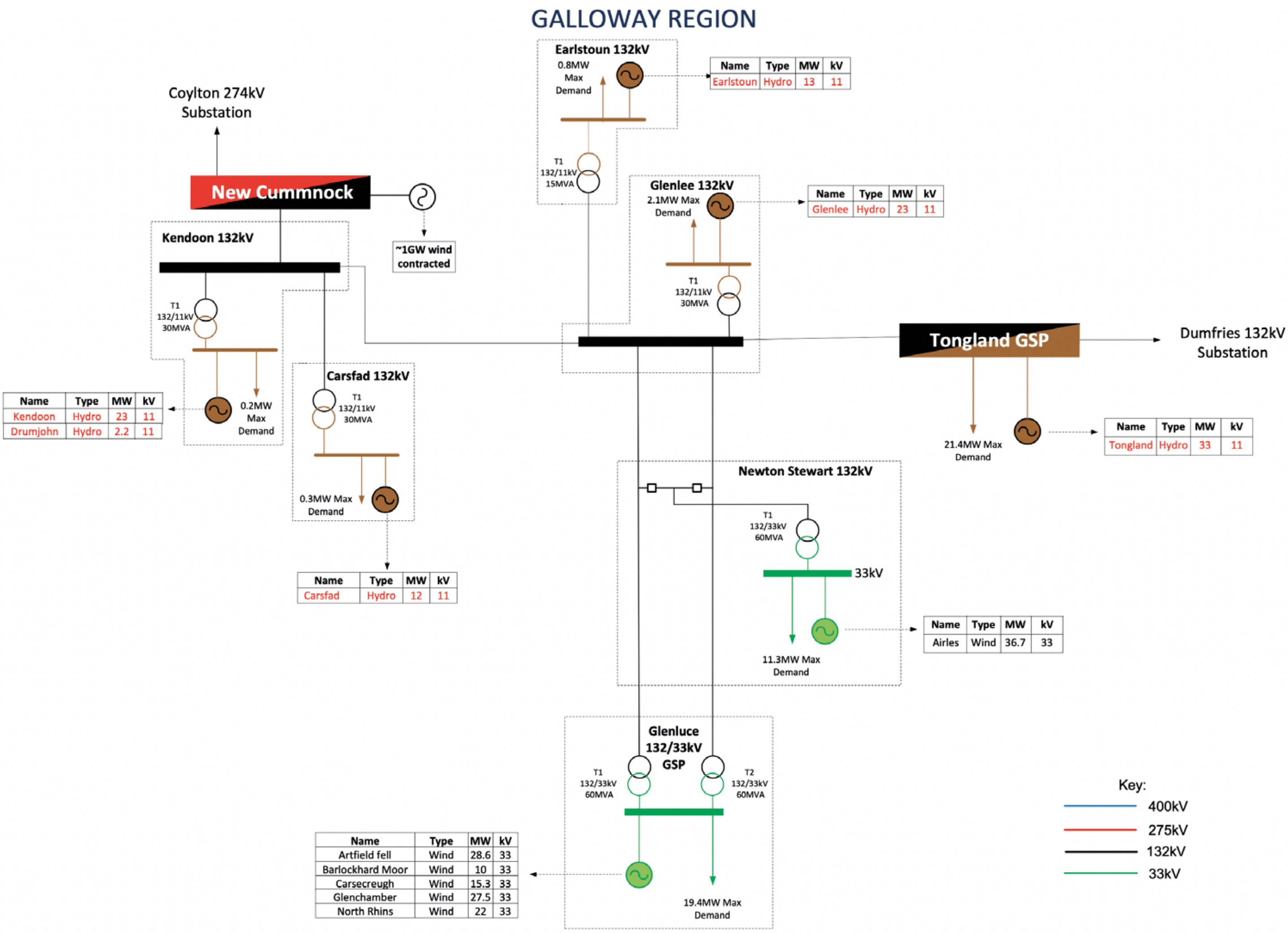
Carrington 132kV
The 132kV generation of about 138 MW is connected at Winnington. The combined Carrington-Fiddlers Ferry 33kV and 132kV minimum load seen by this generating station is about 96 MVA. While this generator alone can take care of the minimum load in the group, the other downstream generators at 33kV in the associated 33kV groups would help in meeting further load demands and improve overall voltage profile.

Case study 10 (SPM) Maentwrog

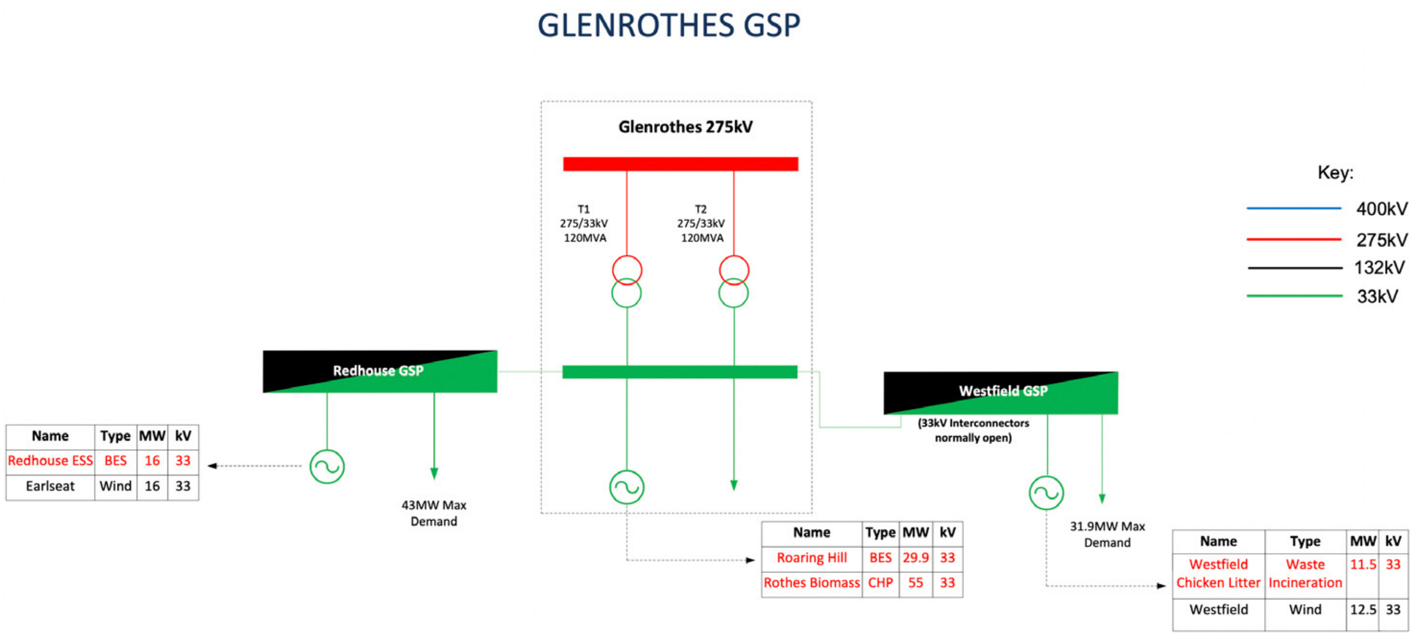
This group has about 39.8 MW of anchor generation and minimum load of about 8.2 MVA. The generating stations are Maentwrog (29.6 MW connected) and Cwm Dyli (10.2 MW connected). This group has excess generation compared to minimum load and thus realistically would have spare capacity to export to the 132kV network if technically feasible. There is an additional 46 MW of solar and wind generation connected at 33kV.

Appendix B – case study diagrams

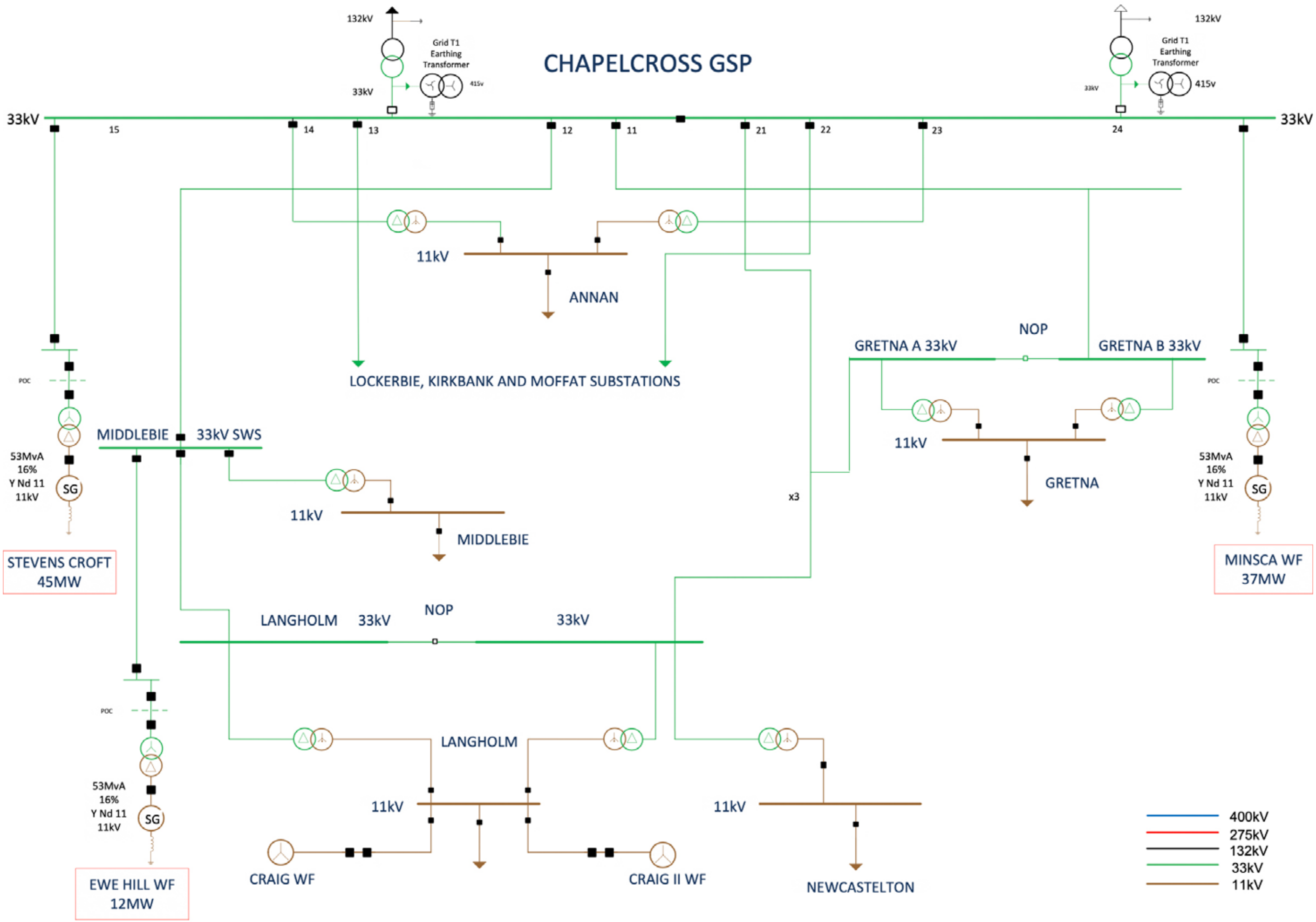
Case study 1
Galloway Region



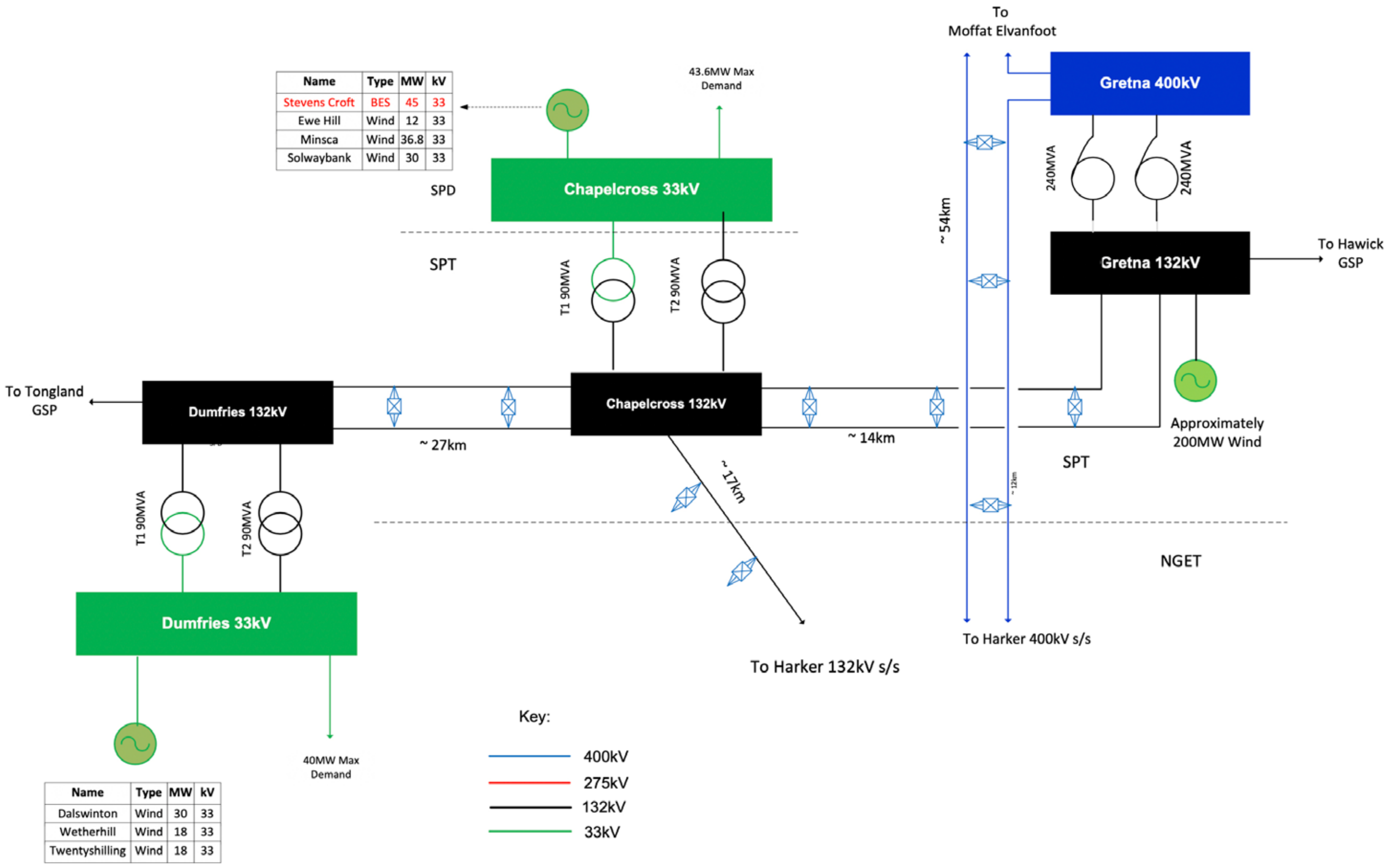
Case study 2
Glenrothes Region



Case study 3
Chapelcross GSP (33kV schematic)



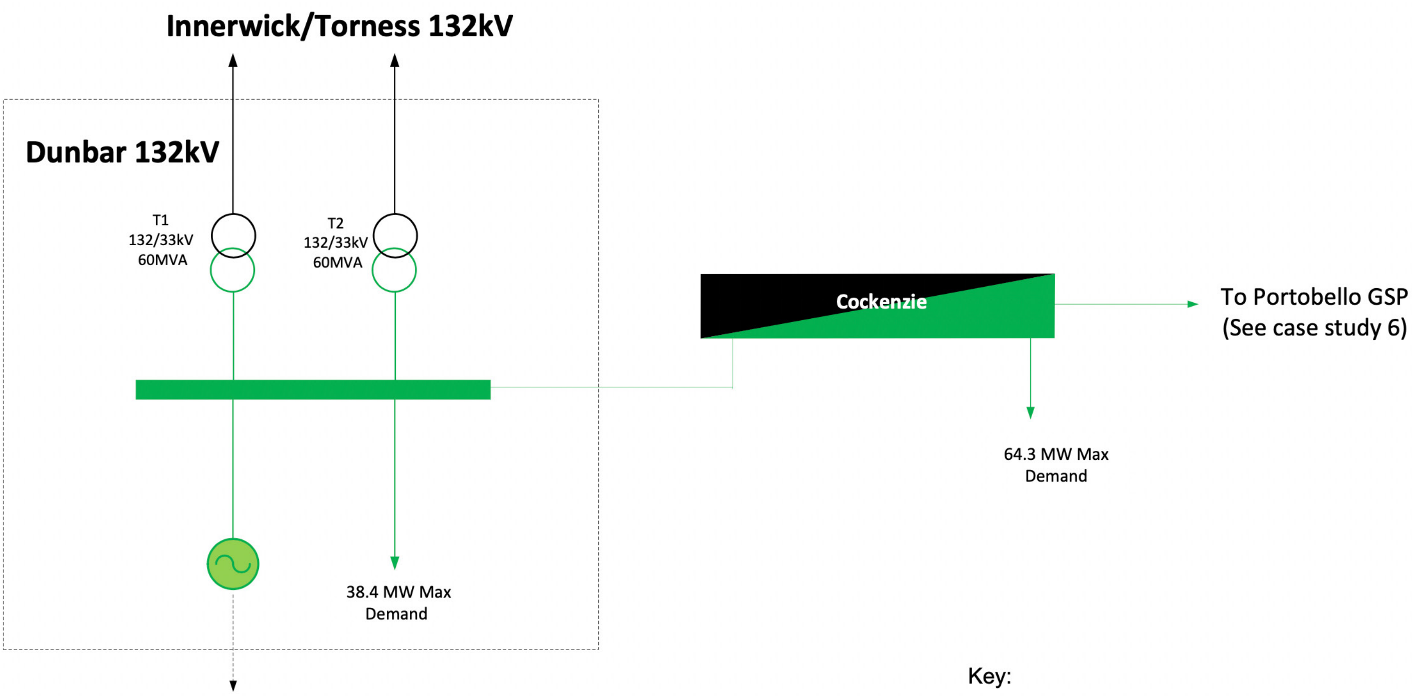
Case study 3
Chapelcross GSP (wider network)



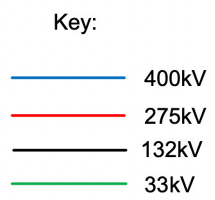
Name	Type	MW	kV
Stevens Croft	BES	45	33
Ewe Hill	Wind	12	33
Minsca	Wind	36.8	33
Solwaybank	Wind	30	33

Name	Type	MW	kV
Dalswinton	Wind	30	33
Wetherhill	Wind	18	33
Twentyshilling	Wind	18	33

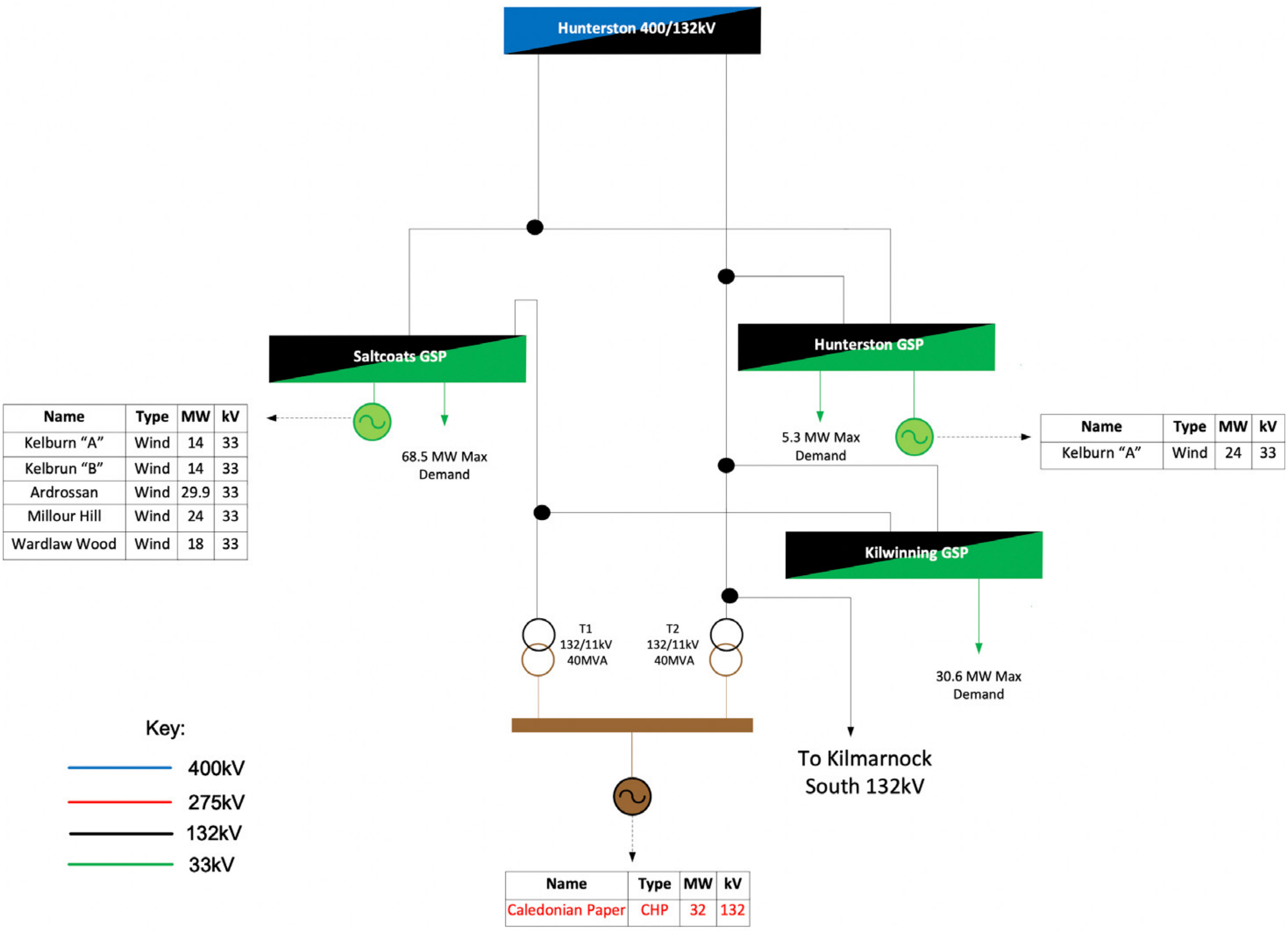
Case study 4
Dunbar GSP



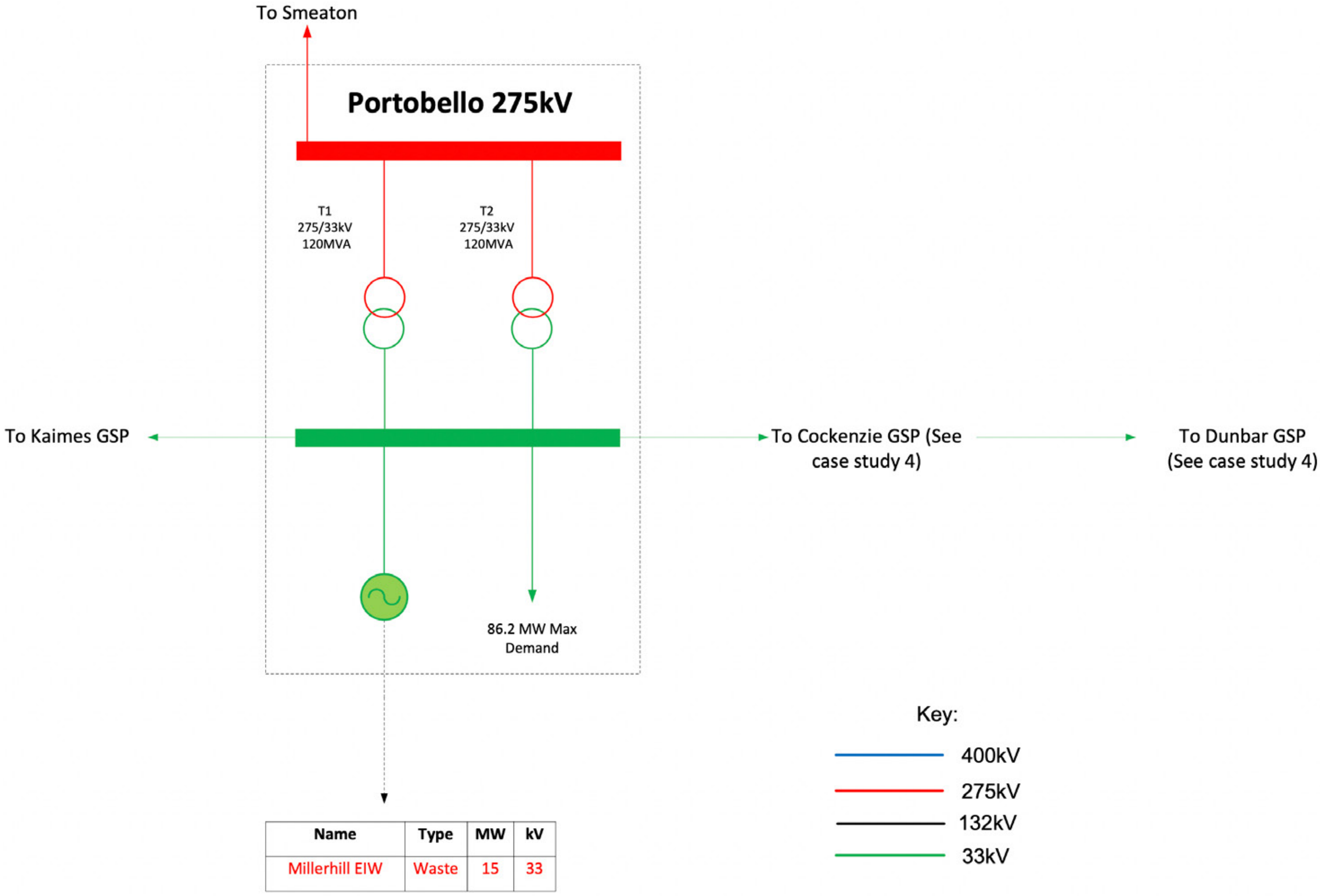
Name	Type	MW	kV
Aikengall	Wind	48	33
Crystal Rig	Wind	62.5	33
Hoprigshiels	Wind	7.5	33
Lafarge Cement	Waste	5.3	33
Dunbar ERF	Waste	36	33



Case study 5
Meadowhead

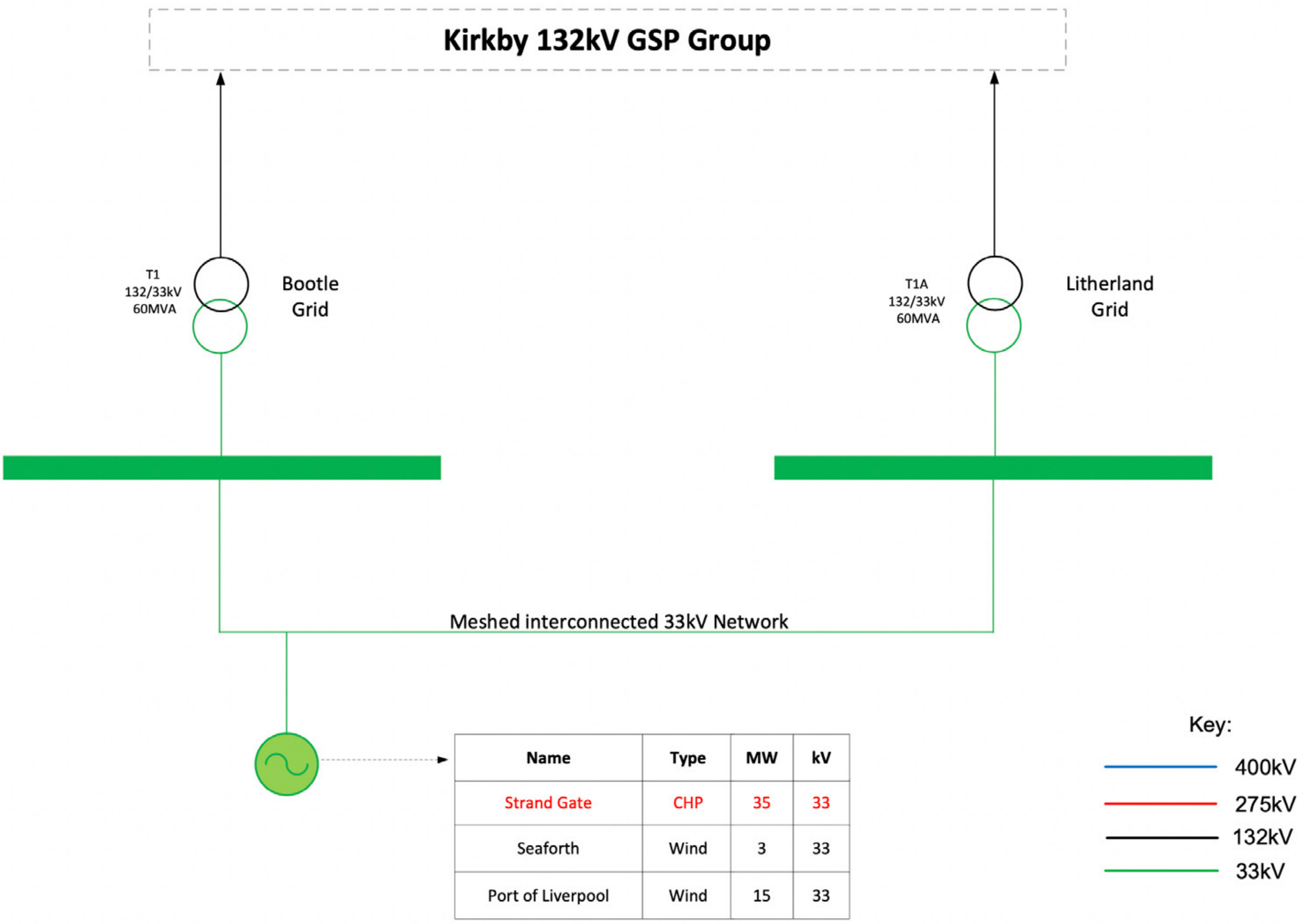


Case study 6
Portobello GSP



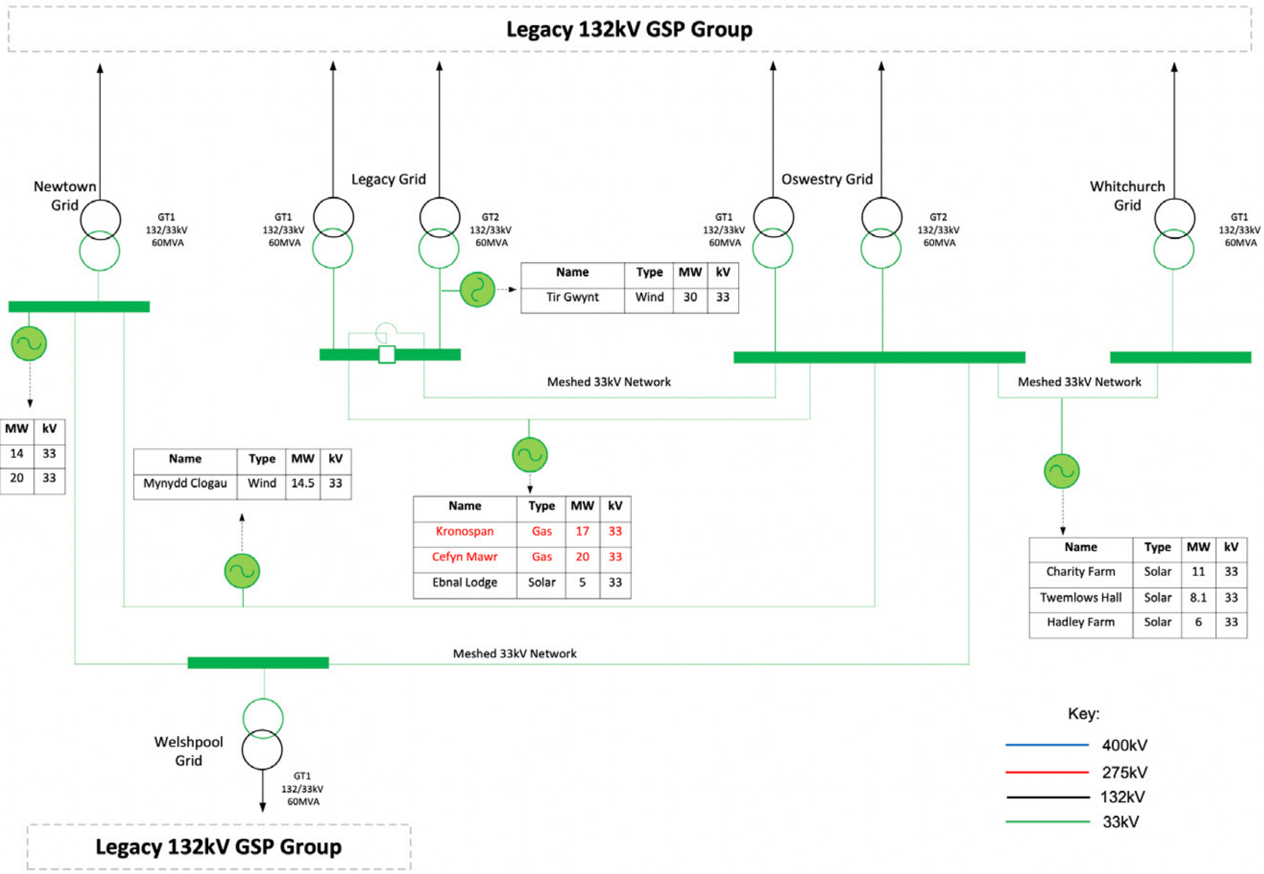
Name	Type	MW	kV
Millerhill EIW	Waste	15	33

Case study 7
Bootle



Name	Type	MW	kV
Strand Gate	CHP	35	33
Seaforth	Wind	3	33
Port of Liverpool	Wind	15	33

Case study 8
Legacy



Name	Type	MW	kV
Tir Gwynt	Wind	30	33

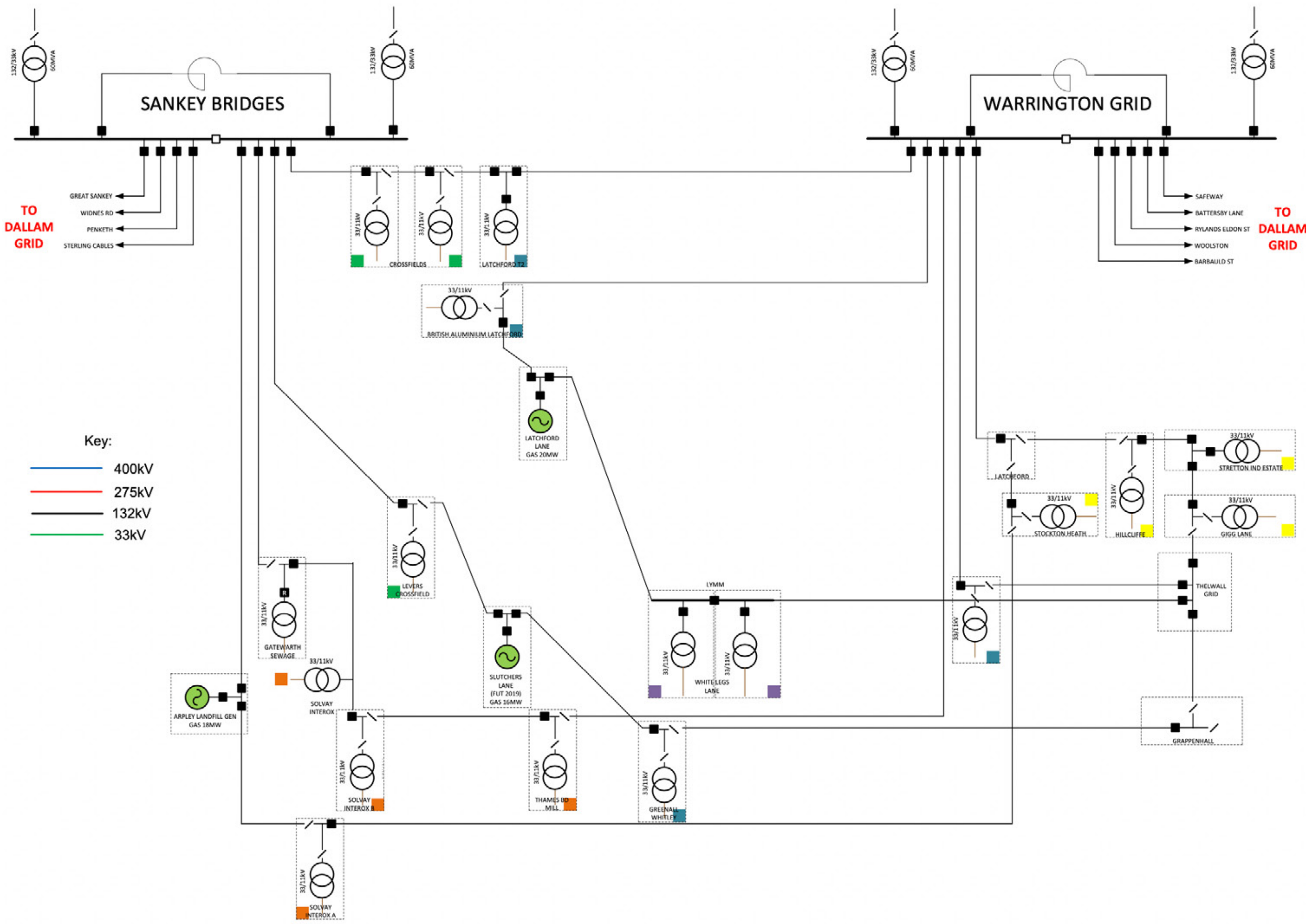
Name	Type	MW	kV
Penrhuddlan	Wind	14	33
Llidiartywaun	Wind	20	33

Name	Type	MW	kV
Mynydd Clogau	Wind	14.5	33

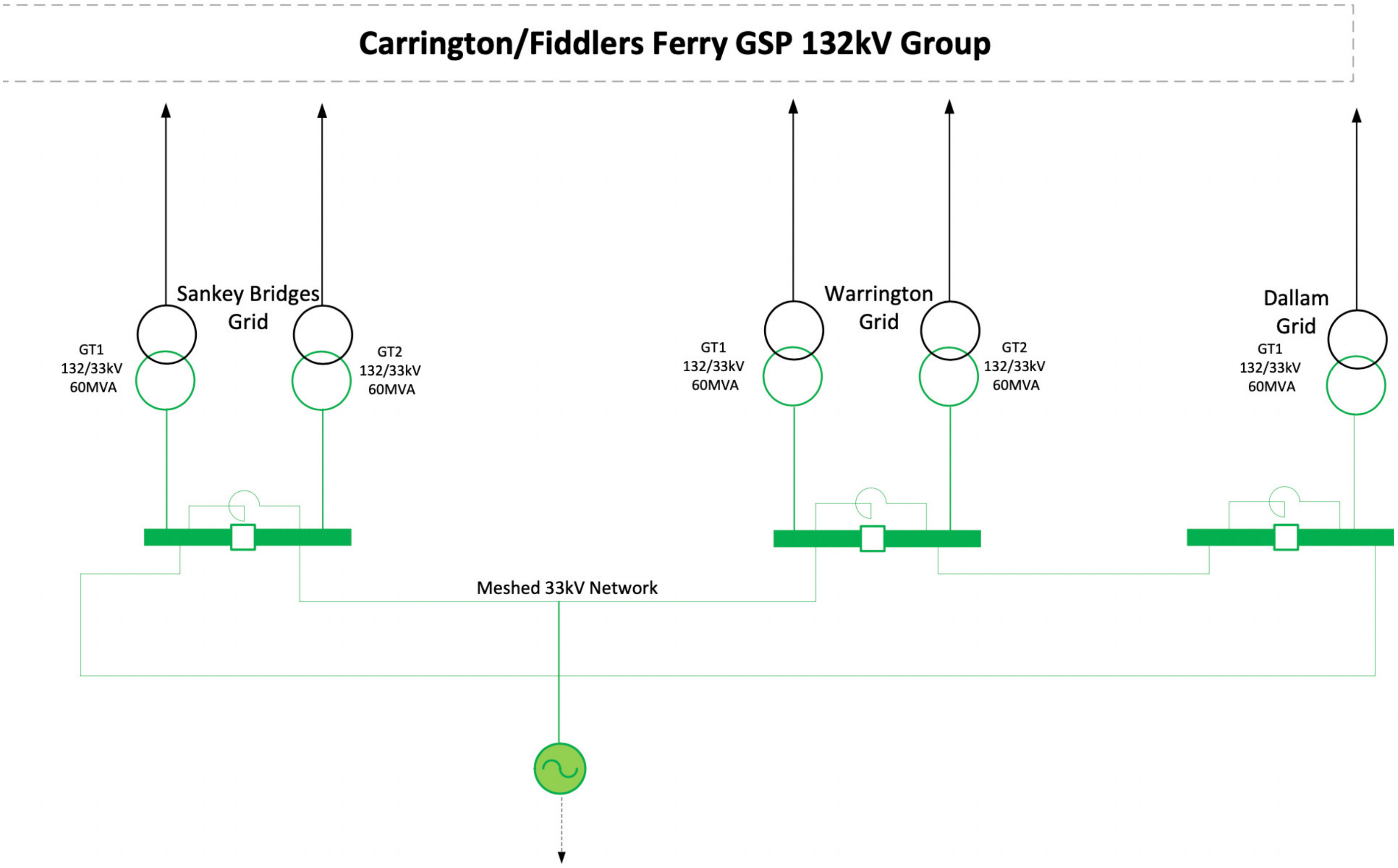
Name	Type	MW	kV
Kronospan	Gas	17	33
Cefyn Mawr	Gas	20	33
Ebnal Lodge	Solar	5	33

Name	Type	MW	kV
Charity Farm	Solar	11	33
Twemlows Hall	Solar	8.1	33
Hadley Farm	Solar	6	33

Case study 9
Sankey Bridges (33kV schematic)



Case study 9
Sankey Bridges (wider network)

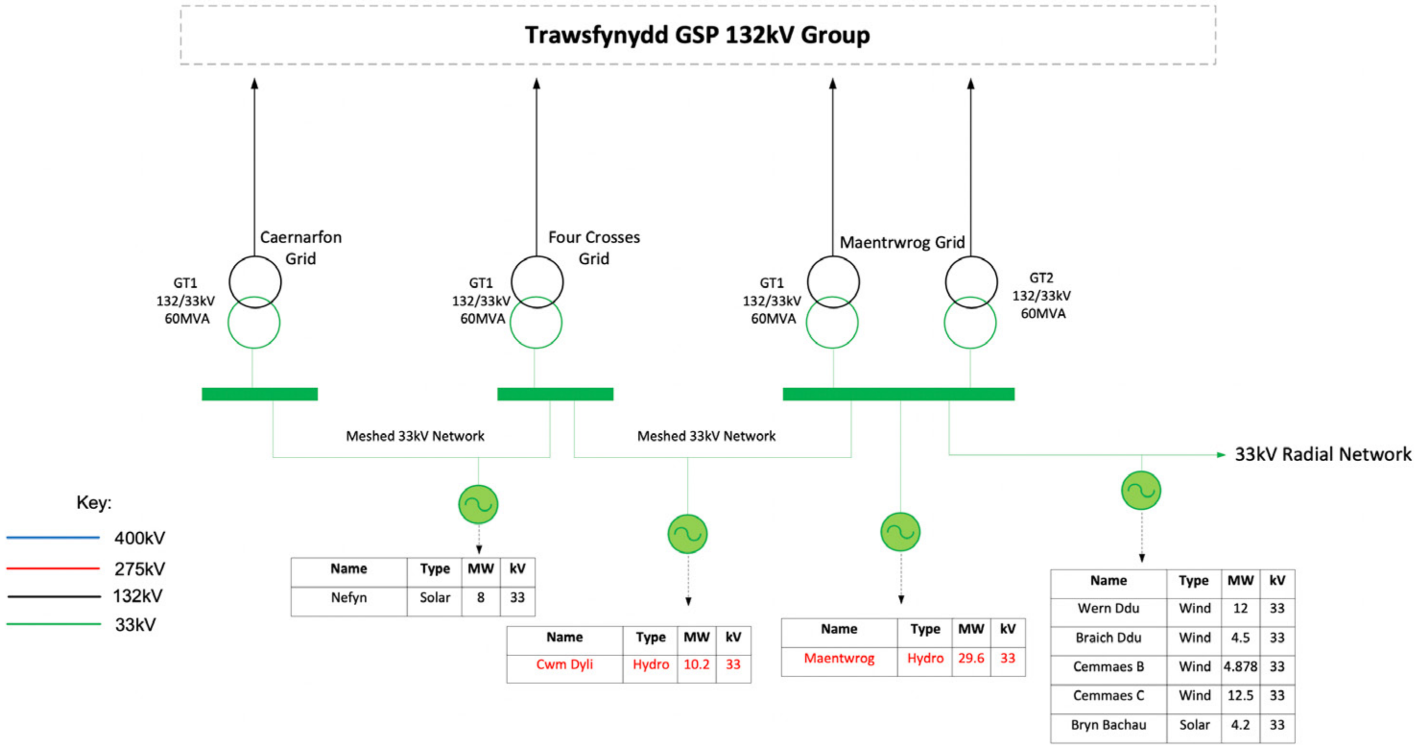


Name	Type	MW	kV
Warrington Power	Gas	16	33
Arpley Landfill	Landfill Gas	18	33
Latchford Lane	Gas	20	33
Winnington	CHP	138	33
Wincham Lane Farm	Diesel	20	33
Sandbach	CCGT	48	33
Widdlewich Power	Gas	21.18	33
Safeguard, Bradwall	Solar	3.9	33

Key:

- 400kV
- 275kV
- 132kV
- 33kV

Case study 10
Maentwrog



Appendix C – case study data sheets

GSP/BSP - Case Study Summary Sheet

Region	Galloway Region
GSP/BSP Name:	Glenlee/Glenluce/Newton Stewart/Tongland/Kendoon
Voltage Ratio:	132/11; 132/33; 132/33; 132/11; 132/11
SPD/SPM:	SPD

LIVE TRIAL potential	Yes	Yes/No

(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Drumjohn	Kendoon GSP	Hydro	2.2	11	Connected		
Glenlee	Glenlee GSP	Hydro	23	11	Connected	Drax	
Kendoon	Kendoon GSP	Hydro	23	11	Connected		
Tongland	Tongland GSP	Hydro	33	11	Connected		
		Total	81.2				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Airies Windfarm	Newton Stewart GSP	Onshore Wind	36.7	33	Connected	NTR	Right
Artfield Fell Windfarm	Glenluce GSP	Onshore Wind	28.6	33	Connected	SSE Renewables	Right
Barlockhart Moor Windfarm	Glenluce GSP	Onshore Wind	10	33	Connected	Natural Power	Right
Carsecreugh Windfarm	Glenluce GSP	Onshore Wind	15.3	33	Connected	DNVGL	Right
Glenchamber Windfarm	Glenluce GSP	Onshore Wind	27.5	33	Connected	RES	Left
North Rhins Windfarm	Glenluce GSP	Onshore Wind	22	33	Connected	SPR	Left
		Total	140.1				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Owner/ Operator	Developer	Swichboard
Plascow Windfarm	DALBEATTIE (11kV)	Onshore Wind	2.4	11	Connected		
		Total	2.4				

No. of different technologies (excl 11kV gen)	2
Max Demand GSP (MW)	63
Min Demand GSP (MW)	16
Number of Primaries	13
Anchor DER Total MW	81.2
Additional DER Total MW	140.1
Anchor DER/Additional DER MW Ratio (%)	58%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:

Interconnection at glenlee means the load can be secured in the event of a live trial. Additionally, Tongland Hydro is directly connected to Both sides of the GSP switchboad, the primary substation loads can therefore be met is half of the board is switched out.

Additional Info:

significant transmission-connected renewable generation resources in that area

Conclusions

Syncronous generation in this area has enough capacity to service all load. A further 140MW of 33kV wind and significant generation on the transmission system could make this area a good contender for live trial.

GSP/BSP - Case Study Summary Sheet

Region	Glenrothes Region
GSP/BSP Name:	Glenrothes/ Westfield/Redhouse
Voltage Ratio:	275/33; 132/33; 132/33
SPD/SPM:	SPD

LIVE TRIAL potential	Yes	Yes/No

(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Redhouse ESS	REDHOUSE (33kV)	BES	16	33	01/11/2019	The Greenspan Agency Ltd	
Roaring Hill Energy Sto	Glenrothes GSP	BES	29.9	33	01/04/2019	Renewable Energy Systems Ltd	
Rothes Biomass	Glenrothes GSP	CHP	55	33	Connected	RWE	Half on each bar
Westfield Chicken Litte	Westfield GSP	Waste Incineration	11.5	33	Connected	EPR Scotland Ltd	Right
		Total	112.4				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Earlseat Windfarm	Redhouse GSP	Onshore Wind	16	33	Connected	RES	Right
Westfield Wind Farm	Westfield GSP	Onshore Wind	12.5	33	Connected	Ventient Energy	Right
		Total	28.5				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Dean foods Wind	REDHOUSE (11kV)	Onshore Wind	1.5	11	Connected		
Goathill Quarry Wind T	COWDENBEATH (11kV)	Onshore Wind	1.5	11	Connected		
Middle Balbeggie Sola		Photovotaic	3.8	11	Connected		
Middle Balbeggie Wind	MIDDLE BALBEGGIE	Onshore Wind	6.4	11	Connected		
Mossmorran Windfarm	COWDENBEATH (11kV)	Onshore Wind	4.6	11	Connected		
Skeddoway Farm Wind	SOUTHFIELD (11kV)	Onshore Wind	2.5	11	Connected		
West Strathore Solar P	REDHOUSE (11kV)	Photovotaic	4.5	11	Connected		
		Total	24.8				

No. of different technologies (excl 11kV gen)	4
Max Demand GSP (MW)	119
Min Demand GSP (MW)	30
Number of Primaries	12
Anchor DER Total MW	112.4
Additional DER Total MW	28.5
Anchor DER/Additional DER MW Ratio (%)	394%

	132kV	275kV	400kV
Voltages in Live Trial area	Y	Y	

Miscellaneous

Network isolation for live trial - Comments:

Rothes Biomass is connected to both sides of the switchboard.
Colydean is a single transformer primary connected to the right half of the switchboard.
Interconnection to Redhouse is available from either half of the switchboard
Interconnection from westfield is available via the left half of the switchboard

Additional Info:

Conclusions

Glenrothes poses good potential as a live trial site. The interconnection via the left side of the switchboard could provide extra security of supply to customer or used to trial synchronisation to a 33kV power Island

GSP/BSP - Case Study Summary Sheet

Region	Chapelcross
GSP/BSP Name:	Chapelcross
Voltage Ratio:	132/33
SPD/SPM:	SPD

LIVE TRIAL potential: Yes — Yes/No
(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Steven's Croft Biomass	Chapelcross GSP	Biomass & Energy Crops (not CHP) (>=1MW)	45	33	Connected	E.ON	Left
		Total	45				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Ewe Hill Windfarm	MIDDLEBIE (33kV)	Onshore Wind	12	33	Connected	SPR	Left
Minsca Windfarm	Chapelcross GSP	Onshore Wind	36.8	33	Connected	Ventient Energy	Right
Solwaybank Windfarm	Chapelcross GSP	Onshore Wind	30	33	30/03/2019	RES	Right
	Total		78.8				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Craig II Windfarm	LANGHOLM (11kV)	Onshore Wind	4.7	11	Connected		
Craig Windfarm	LANGHOLM (11kV)	Onshore Wind	8	11	Connected		
		Total	12.7				

No. of different technologies (excl 11kV gen)	2
Max Demand GSP (MW)	54
Min Demand GSP (MW)	13
Number of Primaries	8
Anchor DER Total MW	45
Additional DER Total MW	78.8
Anchor DER/Additional DER MW Ratio (%)	57%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:

Middlebie can be back feed via 11kV from, Lockerbie, Langholm, Annan and Gretna. 33kV yes for load from Langholm and Chapel cross, no for generation as Ewe hill needs to be constrained due to conductor size on 33k cct.

Additional Info:

Voltage issues on primary feeders under n-1 (ref Moffat new IP1/ STATCOM studies)

Conclusions

A good cases study to test an area of rural network with long circuit lengths. The exiting voltage issues may limit the potential for a live trial due to the increaed risk to loss of supply for customers.

GSP/BSP - Case Study Summary Sheet

Region	Dunbar
GSP/BSP Name:	Dunbar
Voltage Ratio:	132/33
SPD/SPM:	SPD

LIVE TRIAL potential	Yes	Yes/No

(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Lafarge Cement	OXWELL MAINS (33kV)	Waste Incineration	5.3	33	Connected		Right
Dunbar ERF	OXWELL MAINS (33kV)	Waste Incineration	36	33	Connected	Viridor	Right
		Total	41.3				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Aikengall Windfarm	Dunbar GSP	Onshore Wind	48	33	Connected	Community Wind Power	Left
Crystal Rig Windfarm	Dunbar GSP	Onshore Wind	62.5	33	Connected	Fred Olsen	Right
Hoprigshiels Windfarm	INNERWICK SW STN (33kV)	Onshore Wind	7.5	33	Connected	Wood Group	Left
		Total	118				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Ferneylea Farm Windf	TORNESS (11kV)	Onshore Wind	1.6	11	Connected		
Kinegar Quarry	TORNESS (11kV)	Onshore Wind	5	11	Connected		
		Total	6.6				

No. of different technologies (excl 11kV gen)	2
Max Demand GSP (MW)	26
Min Demand GSP (MW)	7
Number of Primaries	5
Anchor DER Total MW	41.3
Additional DER Total MW	118
Anchor DER/Additional DER MW Ratio (%)	35%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:

36MW Anchor connected to the same side of the bar as a 62.5MW WF.
Belhaven forth is a single transformer primary connected to the right half of the switchboard. The primary also has interconnection to cockenzie and is connecked at 33kV to North Berwick Primary T2.

Additional Info:

Conclusions

This site has live trial potential due to the layout of generation, 33kV interconnection and low levels of load.

GSP/BSP - Case Study Summary Sheet

Region	Meadowhead
GSP/BSP Name:	Meadowhead/Saltcoats/Kilwinning
Voltage Ratio:	132/33
SPD/SPM:	SPD

LIVE TRIAL potential: Yes (Yes/No)
(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Caledonian Paper	Meadowhead Substation (132kV)	CHP	32	132	Connected		
		Total	32				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Ardrossan Windfarm	Saltcoats Grid	Onshore Wind	29.9	33	Connected		
Kelburn "A" Windfarm	Saltcoats - FAIRLIE (33kV)	Onshore Wind	14	33	Connected		
Kelburn "B" Windfarm	Saltcoats - FAIRLIE (33kV)	Onshore Wind	14	33	Connected		
Millour Hill Windfarm	Saltcoats Grid	Onshore Wind	24	33	Connected		
Wardlaw Wood Windfarm	Saltcoats - KILBIRNIE (33kV)	Onshore Wind	18	33	Connected		
		Total	99.9				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Barkip Anaerobic Digestor	Saltcoats - KILBIRNIE (11kV)	Other generation (>=1MW)	2.2	11	Connected		
Barkip Landfill	Saltcoats - KILBIRNIE (11kV)	Waste Incineration	1.2	11	Connected		
Halkshill Hydro	Saltcoats - LARGS (11kV)	Hydro	1.1	11	Connected		
Lochcraigs Solar Park	Saltcoats - BYREHILL (11kV)	Photovotaic	4.75	11	Connected		
Roche CHP	Killwinning - ROCHE PRODUCTS (Customer substation)	CHP	16	11	Connected		
Tourgill Hydro	Saltcoats - LARGS (11kV)	Hydro	0.6	11	Connected		
		Total	25.85				

No. of different technologies (excl 11kV gen)	2
Max Demand GSP (MW)	108
Min Demand GSP (MW)	27
Number of Primaries	9
Anchor DER Total MW	32
Additional DER Total MW	99.9
Anchor DER/Additional DER MW Ratio (%)	32%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:
Caledonian Paper is a transmission connection.
Interconnection is available at 132kV to Saltcoats and Kilwinning
Saltcoats has an A & B switchboard
Millour Hill WF is connected to the right side of switchboard A; The Primary substation at Saltcoats A can be served from either half of the 33kV Switchboard

Additional Info:
11kV generators connected directly to 132kV is commonly found on the LPN Network area

Conclusions
This case study provides an example similar to other area's of the UK.

GSP/BSP - Case Study Summary Sheet

Region	Portobello	LIVE TRIAL potential	Yes	Yes/No
GSP/BSP Name:	Portobello	(meets essential criteria)		
Voltage Ratio:	275/33kV			
SPD/SPM:	SPD			

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Millerhill EfW	NIDDRIE (33kV)	Waste Incineration	15	33	Connected		
		Total	15				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
		Total	0				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Carcant Windfarm	LADY VICTORIA (11kV)	Onshore Wind	6	11	Connected		
Drummond Moor Landfill	LADY VICTORIA (11kV)	Waste Incineration	0.8	11	Connected		
Millerhill Zero Waste	NIDDRIE (11kV)	CHP	1.5	11	Connected		
Oatslie Sand Pit Landfill	LADY VICTORIA (11kV)	Waste Incineration	2.63	11	Connected		
Seafield Sewage Plant	PORTOBELLO (11kV)	Waste Incineration	3.19	11	Connected		
Waverley Cres CHP	LADY VICTORIA (11kV)	CHP	0.33	11	Connected		
		Total	14.45				

No. of different technologies (excl 11kV gen)	1
Max Demand GSP (MW)	98
Min Demand GSP (MW)	25
Number of Primaries	6
Anchor DER Total MW	15
Additional DER Total MW	0
Anchor DER/Additional DER MW Ratio (%)	

	132kV	275kV	400kV
Voltages in Live Trial area		Y	

Miscellaneous

Network isolation for live trial - Comments:

Millerhill EfW connects to Portobello Grid via Niddrie sw/stn. The side of the switchboard that the sw/stn connects to feeds a single transformer primary, Lochend Quadrant. LV interconnection is available to Easter Road, Lower London Road and Bonnington Primaries.

Additional Info:

Conclusions

Portobello GSP provides an example of a common network, where only a single grid forming generator is connected. The aspiration from studying this network topology is to asertain if a single grid forming generator can

GSP/BSP - Case Study Summary Sheet

Region	Bootle
GSP/BSP Name:	BOOTLE GT1 / LITHERLAND GT1A
Voltage Ratio:	132/33
SPD/SPM:	SPM

LIVE TRIAL potential: Yes (Yes/No)
(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Strand Gate	01/3395/037/E Strand Gate Bootle	CHP	35	33	Connected		
		Total	35				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Seaforth Wind Farm	PS-SJ3297/023 MDHB Freeport	Wind Onshore	3	33	Connected		
Port Of Liverpool Wind Farm	01/3394/015/E Sheppards Alexandra Dock	Wind Onshore	15	33	Connected		
		Total	18				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Tesco Sefton Street	TESCO SEFTON STREET 01/3397/035 GM S/S	TBA		HV	Connected		
		Total	0				

No. of different technologies (excl 11kV gen)	2
Max Demand GSP (MW)	50
Min Demand GSP (MW)	13
Number of Primaries	10
Anchor DER Total MW	35
Additional DER Total MW	18
Anchor DER/Additional DER MW Ratio (%)	194%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:

Additional Info:

Conclusions

GSP/BSP - Case Study Summary Sheet

Region	Legacy	**LIVE TRIAL potential**	Yes	Yes/No
GSP/BSP Name:	Legacy 132kV & Legacy Local	(meets essential criteria)		
Voltage Ratio:	400/132/33			
SPD/SPM:	SPM			

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Kronospan	04/2838/009/E-CADBURYS - KRONOSPAN	Gas	17	33	Connected		
Cefyn Mawr	Ruabon	DIESEL	20	33	Connected		
		Total	37				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Tir Gwynt	Legacy 132kV - Tir Gwynt Windfarm	Wind Onshore	30	132	Connected		
Twemlows Hall Solar Park	TWEMLOWS Solar PARK	Solar	8.1	33	Connected		
Trench Farm Solar Farm	TRENCH FARM Solar PARK SJ3839/005	Solar	5	33	Connected		
The Grange (plas Bennion Rd)	SJ2843/021 Plas Bennion Road Solar Farm	Solar	4.75	33	Connected		
Penrhyddlan	09/0186/005/E Llandinam	Wind Onshore	14	33	Connected		
Mynydd Clogau	09/1099/008/E Tregynon	Wind Onshore	14.5	33	Connected		
Llidiartywaun	09/0186/005/E Llandinam	Wind Onshore	20	33	Connected		
Hadley Farm	HADLEY Solar FARM	Solar	6	33	Connected		
Fields Farm 1	FIELDS FARM Solar AGDEN SJ5144/006	Solar	3.5	33	Connected		
Ebnal Lodge PV Generation	Ebnal Solar Park	Solar	5	33	Connected		
Charity Farm	Charity Farm Solar	Solar	11	33	Connected		
Acrefair Solar Park	SJ2844/005 Delph Road Soalr Farm	Solar	3.75	33	Connected		
		Total	125.6				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Wynnstay Farmers	09/2220/001 Wynnstay Farmers	Solar	1.2	HV	Connected		
Shanks	SHANKS 04/2941/005 GM S/S	Landfill Gas	2	HV	Connected		
Ruabon Landfill	RUABON LANDFILL 04/3044/018	Landfill Gas	2.24	HV	Connected		
Red house	SJ4020/054 RED HOUSE	Solar	0.5	HV	Connected		
Pentons	09/3027/005/ Pentons	TBA	1.25	HV	Connected		
Oswestry WTW	09/2729/003/E-NWW LLANFORDA	Diesel	1.88	HV	Connected		
Moor Farm	MOOR Solar FARM SJ4123/001	Solar	3	HV	Connected		
Manor Farm	GSS-SJ2924/016 MANOR FARM PV GENERATION	Solar	2.5	HV	Connected		
Legacy Solar Farm	LEGACY Solar FARM SJ2848/015	Solar	2.4	HV	Connected		
Red house	GSS-SJ4020/054 RED HOUSE	Biogas CHP	1	HV	Connected		
Cold Store	09/5541/010 COLD STORE	Biogas CHP	1	HV	Connected		
Bryn Posteg Landfill	09/9782/005/ -BRYN POSTEG LANDFILL SITE	Landfill Gas	2.13	HV	Connected		
Anglo Beef Products	CITY MEATS 09/3928/001	Synchronous	1.16	HV	Connected		
Abbotsmoor Farm	GSS-SJ3727/009 POTATO FARM	Anerobic Digester	1.5	HV	Connected		
Oaklands	Oaklands SJ3928/009	Synchronous	0.75	HV	Connected		
Wykey Farm	WYKEY FARM SJ3825/004	Anerobic Digester	1.9	HV	Connected		
Abertanat Farm	Abertanat Farm SJ2521/007	Gas	0.75	HV	Connected		
		Total	27.16				

No. of different technologies (excl 11kV gen)	4
Max Demand GSP (MW)	184
Min Demand GSP (MW)	62
Number of Primaries	40
Anchor DER Total MW	37
Additional DER Total MW	125.6
Anchor DER/Additional DER MW Ratio (%)	29%

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:	Additional Info:	Conclusions

GSP/BSP - Case Study Summary Sheet

Region	Sankey Bridges
GSP/BSP Name:	Carrington 132kV/ 191/ 195
Voltage Ratio:	132/33
SPD/SPM:	SPM

LIVE TRIAL potential: Yes (Yes/No)

(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Warrington Power	Slutchers Lane (191)	Gas	16	33	Future-2019		
Arpley Landfill	03/5986/005/E Arpley Lanfill Gen (191)	Landfill Gas	18	33	Connected		
Latchford Lane	Thelwall Lane (191)	Gas	20	33	Connected		
Winnington	BM Winnington (Carrington 132kV)	CHP	138	132	Connected		
Wincham Lane Farm	Wincham Lane (195)	Diesel	20	33	Future - Q4 2019		
Sandbach CHP	06/7263/007/G Elworth Grid (195)	CCGT	48	33	Connected		
Middlewich Power Ger	Middlewich Power (195)	Gas	21.18	33	Future - Q4 2019		
		Total	281.18				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Safeguard, Bradwall 1 PV Solar Park	PS-SJ7463/003 SAFEGUARD GENERATION	Solar	3.9	33	Connected		
		Total	3.9				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
		Total	0				

No. of different technologies (excl 11kV gen)	1
Max Demand GSP (MW)	164
Min Demand GSP (MW)	54
Number of Primaries	37
Anchor DER Total MW	281.18
Additional DER Total MW	3.9
Anchor DER/Additional DER MW Ratio (%)	

	132kV	275kV	400kV
Voltages in Live Trial area	Y		

Miscellaneous

Network isolation for live trial - Comments:

Additional Info:

Conclusions

Region	**Maentwrog**
GSP/BSP Name:	Maentwrog
Voltage Ratio:	132/33
SPD/SPM:	SPM

LIVE TRIAL potential	Yes	Yes/No

(meets essential criteria)

Return to

Anchor DER (33kV or 132kV)

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Maentwrog	Maentwrog Grid	Hydro	29.6	33	Connected		
Cwm Dyli	Cwm Dyli	Hydro	10.2	33	Connected		
		Total	39.8				

Additional DER

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Wern Ddu	Derwen	Wind Onshore	12	33	Connected		
Nefyn Solar Farm	PS-SH3337/004 NEFYN Solar PARK	Solar	8	33	Connected		
Cemmaes C	10/8605/001/E-FFERM WYNT CEMMAES	Wind Onshore	12.5	33	Connected		
Braich Ddu Wind Farm	04/0141/002/E Braich DDU Wind Farm	Wind Onshore	4.5	33	Connected		
Cemmaes B	10/8605/001/E-FFERM WYNT CEMMAES	Wind Onshore	4.878	33	Connected		
		Total	41.878				

11kV Gen connected

Gen Name	Substation	Technology	MW	kV	Status	Owner/ Operator	Swichboard
Melin Wynt	MELIN WYNT GEN SH9846/003	Wind Onshore	1	HV	Connected		
Nant Bach Scheme	NANT BACH WIND GEN SH9947/001	Wind Onshore	1.5	HV	Connected		
Trweryn Lake Hydro	TREWERYN LAKE HYDRO SH8440/061	Hydro	4.507	HV	Connected		
Liverpool Corporation Pov	LPOOL CORP POWER HSE 04/8739/001	Hydro	4	HV	Connected		
Gelli Gron 1	GELLI GRON LLEOL SH4140/052	Solar	2.3	HV	Connected		
Hafoty Ucha	Windfarm 04/9345/001	Wind Onshore	3	HV	Connected		
Clegir Ganol Wind	Clegir Ganol Wind SJ0446/001	Wind Onshore	0.45	HV	Connected		
Bryn Bachau	SH4237/007 Bryn Bachau Solar Farm	Solar	4.2	11	Connected		
		Total	20.957				

No. of different technologies (excl 11kV gen)	3
Max Demand GSP (MW)	68
Min Demand GSP (MW)	8
Number of Primaries	27
Anchor DER Total MW	39.8
Additional DER Total MW	41.878
Anchor DER/Additional DER MW Ratio (%)	95%

	132kV	275kV	400kV
Voltages in Live Trial area			

Miscellaneous

Network isolation for live trial - Comments:

Additional Info:

Conclusions

Appendix D – stakeholder engagement questionnaire

Name:	
Role:	
Date:	
Name of organisation:	
Type of Distributed Energy Resource (DER) technology:	
Name of DER plant (s):	
Location of plant(s): (closest town)	
Size of Plant(s): (MW)	

Grid connection supply loss and restoration

	Comments
1) What is the current procedure following a loss of the Grid connection (DNO LV supply still available)? What is the impact/requirements if the grid supply is not restored within one, two or three days?	
2) What is the current procedure/ timescale to reconnect to the distribution network when the DNO supply is restored? (Does this vary depending on outage duration?)	

Black Start Resilience (Loss of grid connection and DNO LV supply)

	Comments
3) What is the site Black Start resilience timeline? (e.g after three hours batteries dead, after X standby gen out of fuel, after X boiler/turbine cools down requiring X days to restart, manual intervention required after.. etc	
4) How is the site currently controlled? E.g manned/unmanned, remote via control room? What is the resilience of these communications?	

Power supplies

	Comments
5) Does your site have emergency power and if so for what essential services? Capacity (e.gkVA), Resilience (time)?	
6) Does your site have Auxiliary power (for restarting or maintaining availability of plant? (If so please provide details or if not what capacity might be required?)	

Resilience of supply

	Comments
7) Synchronous gen Can the gen operate at rated output for 72 hours? If not what would be required to obtain this?	
8) Synchronous gen What is the Black Start resilience of the fuel supply (e.g gas supply)?	

	Comments
9) Can the gen perform at least three sequential start-ups/resync?	
10) What is the approximate per cent annual availability of the site?	

Technical

	Comments
11) Do you have existing voltage control capability? (If so where is the voltage measured?)	
12) Do you have existing frequency control capability?	
13) Other relevant technical capability if known/applicable. E,g • What is the minimum operating MW level? • Can you provide reactive capability if no wind (for WFs)? • Fault infeed? • Others?	

Contacts

	Comments
14) Who is the best point of contact for this project?	
15) Is there a technical or manufacturer contact?	

Appendix G – overview of typical DNO earthing arrangements

Solid earthing

- A direct connection to earth with no intentional impedance in the circuit.
- Fault current is high leading to faster fault clearance times.
- Good control is achieved with respect to overvoltages.
- However, the high current poses a risk for equipment damage especially from faults if arcs form.

In the Black Start configuration fault levels on a solidly earthed system will be greatly reduced due to the increase in the source impedance.

Impedance earthing

- A connection to earth is achieved through an impedance (resistor, reactor, resonant device).
- The fault current magnitude is limited based on the characteristics of the impedance reducing the risk of equipment damage due to arcing faults.
- Limiting the fault current also limits the rise of earth potential on the local earthing system making it easier to achieve safety from step/touch/transfer potentials, protecting those working within substations as well as the general public.
- The fault current, although limited, must be large enough to operate protection within a reasonable timescale.
- The most commonly used method of impedance earthing in GB is through a resistor and in most cases, this is via an earthing transformer on the 33kV delta winding of the grid transformers.

In the Black Start configuration the method of earthing the 33kV system could be selected so that fault levels are similar to those present in normal operation.

Arc suppression coil earthing

Arc Suppression Coils (ASCs) are the predominant neutral earthing system at 33kV and 11kV in Cornwall. The characteristics of this type of earthing scheme are:-

- connection to earth through an Arc Suppression Coil (Petersen Coil, adjustable reactor)
- ASC tuned to compensate the capacitance to earth of the network, accurate tuning is achieved by measuring the voltage across the ASC
- reduced reactive current leads to arcs that cannot maintain themselves and extinguish
- relatively small fault current but this leads to long fault durations (hours)
- protection devices do not operate on fault inception only once the fault is located
- protection therefore ignores temporary faults.

When a single phase to earth fault occurs on a feeder the voltage across the ASC rises to the normal phase to earth voltage of the network. This causes the voltage from each of the two healthy phases to earth to increase to the normal phase to phase voltage. The charging (i.e. capacitive) current from the two healthy phases flows into the fault but this is almost entirely compensated by the reactive current from the ASC, resulting in a relatively small current at the point of fault. On an ASC earthed network an earth fault can be allowed to remain for up to eight hours.

As the magnitude of current at the point of fault is determined by the vector sum of the charging currents and the compensation applied to the network the current will not change for the Black Start scenario provided the connected cables remain the same as the normal operating configuration.

The current at each point of infeed during a fault is the sum of the compensation applied at that point of infeed. Since the extensive connection of cable, currents in excess of 300 A are possible at the ASC earthed BSPs.

In order to minimise the current at the point of fault, the ASC must be retuned whenever the capacitance of the connected network changes significantly, i.e. when feeders are switched in and out. Auto-tuning relays are now available that retune the ASC in response to changes in the steady-state voltage across the ASC. All 33kV ASCs in the WPD Cornwall network are now fitted with auto-tuning relays.

In an ASC-earthed network, the neutral of each feeding transformer (or its associated earthing transformer) is connected to earth via an ASC. Therefore, in the Black Start scenario the transformer winding will need to remain connected so that the ASC is in circuit or the system converted to conventional neutral earthing.

In the Black Start arrangement the existing ASC would need to be used, or the earthing scheme (and associated protection) changed to a different type.

Appendix H – power system studies, SPD case study assessment

Introduction

The analysis was performed in PowerFactory v2018 with the processing of data and results in Excel 2010.

The model of the SPD system was derived from the LTDS v1525_27 Nov2018 model, which represents the system as it is in late 2018. This model has the latest updates to network configuration and parameters.

SPD Network

The SP Distribution System is designed such that GSP substations supply identifiable sections of the distribution network. The various distribution networks are operated radially throughout, utilising standard transformer and cable size.

The Distribution System is configured in a number of standard running arrangements and operates at 33kV and 22kV (EHV), 11kV and 6.6kV (HV) and 400 volts and 230 volts (LV), providing supply to the connection point of all remaining customers for industrial, commercial and domestic purposes.

Extra high voltage (33kV) Distribution System
The SPD primary Distribution System is a group of circuits that provide supplies to primary substations and customers with an Extra High Voltage (EHV) point of supply. These circuits also offer the provision of emergency interconnection between GSPs. The circuits comprise sections of underground cable or overhead line (supported by steel towers or wood poles) or a combination of both.

The EHV system operates at 33kV and 22kV.
The EHV networks are supplied via SP Transmission owned 275/33kV and 132/33kV grid supply transformers of standard size and vector group. Grid supply transformers are connected to the SP Distribution system via 33kV circuit breakers owned by SP Transmission plc.

Each grid supply transformer is equipped with an on-load tap changer and automatic voltage control (AVC) scheme. AVC equipment at GSPs is applied to each transformer such that the transformer secondary voltage is maintained within a pre-defined dead band of +/-2 per cent of the nominal secondary voltage, and ensures that the tap changers on each transformer remain in step. Tele-control facilities allow real-time monitoring and control across the EHV networks.

HV (11kV) Distribution System
The secondary Distribution System is a group of circuits that provide supplies to secondary substations and customers with an HV point of supply. These circuits also offer the provision of interconnection, operated normally open, between primary substations. HV circuits comprise sections of underground cable or overhead line or a combination of both. While some small areas of the HV system in the centres of Glasgow and Edinburgh continue to operate at 6.6kV, the bulk of the HV Distribution System operates at 11kV.

The HV network is supplied from the EHV network at primary substations utilising transformers of standard size and phase connection (normally Dy11). Typically, twin 12/19/24 MVA (or 20/40 MVA) 33/11kV Primary transformers feed a two section 11kV busbar. Each incoming feeder is connected to a different busbar section. The incoming circuits operate in parallel with the bus section circuit breaker normally closed.

On-load tap changers are fitted to present day Primary transformers and are normally of the Standard Random Control type. This allows transformers operating in parallel to be out of step by not more than one tap step. The tap changing equipment is controlled by an Automatic Voltage Control (AVC) relay, which maintains the secondary voltage within limits of +/-2 per cent of the set point voltage under all load conditions. The AVC equipment is normally set to a target 11.2kV voltage at the primary substation HV busbar.

HV switchboards at primary substations usually comprise two sections of busbar with a central normally closed bus section circuit breaker. HV circuits are controlled by a ground mounted circuit breaker and typically form open rings from the two sections of busbar in a primary substation or, form normally open interconnection between primary substations.

Chapelcross case study

Chapelcross network area has a total generation capacity of 93.8 MW connected at 33kV. The group contains a single 51 MW anchor generator with a net export capacity of 45 MW, two connected wind farms with a combined export capacity of 48.8 MW and a contracted wind farm with an export capacity of 30 MW (to be energised in 2019).

This group also has a lot of excess generation compared to the maximum load (52.1MW) and thus, realistically could be used to energise up to the 132kV network. See Appendix A for more details.

This group has been selected due to its long rural lines and the potential to back energise up to the 132kV network and synchronise with NGET at Harker 132kV substation.

Assumptions and modelling

The network model was prepared for the Black Start analysis by making the changes in accordance with the assumptions listed below.

Generator assumptions and modelling

- The minimum power output required to run for the generators involved has been ignored at this stage. It is expected that this information will be provided by the generation sites and will be taken into the detailed power system studies during the design stage.
- As the purpose of these high-level studies is to identify the worst-case scenario for voltage profile and MVAr step change, it has been assumed that the generators are able to provide block loading close to their rated capacity. Detailed studies in the design stage will be used to identify limitations of generators to pick up block loads based on their inertia, reactive power capability, and Automatic Voltage Regulator (AVR) and governor characteristics.
- The auxiliary load demand for all generators has not been taken into account at present.
- Continuous "fuel" availability is considered for all generators.
- A power factor range of 0.85 lag (reactive power export) to 0.95 lead (reactive power import) has been considered at the terminals of the anchor generator (Steven's Croft Biomass).
- 1 p.u. voltage setpoint at the 11kV terminals of the equivalent anchor generators was applied.
- 1 p.u. voltage setpoint at the 33kV terminals of the 33/11kV generator transformers was used.
- A power factor range of 0.95 lag (reactive power export) to 0.95 lead (reactive power import) has been considered at the terminals of the asynchronous generators (Ewe Hill WF).

Network operation assumptions and modelling

- Normal operation was assumed prior to Black Start, e.g. all transformers and lines connected as per normal operation.
- All 132kV, 33kV and 11kV circuit breakers open prior to restoration. All disconnectors are closed.
- Depending on the restoration scenario, some circuit breakers could be maintained closed prior to restoration. For example, assuming technical possible, if the demand on a Primary is picked up simultaneously with the Primary transformer, then the 11kV transformer circuit breaker can be maintained closed prior to restoration.
- Initially, all transformer taps are locked on the positions corresponding to the operation prior to black-out.
- Unless otherwise stated, the OLTC of the 33/11kV transformer has been considered fixed throughout restoration, until the network connected to its 11kV terminals is energised.

SPD radial network

- The Chapelcross case study is representative for a standard British network as it has a radial 33kV network.

The primary substations in this area have peak demands between 1.4 MW and 14.7 MW.

Description of the restoration scenarios

The studied scenarios are combinations of the various restoration alternatives in table 8.1.

Table 8.1
High-level description of various restoration alternatives and studied scenarios

Scenario	High level description	Scope
Scenario I	Anchor generator energises the 33kV network; load is taken on as the power island grows. 33/11kV transformer taps fixed at value prior to blackout.	Identify load flow and fault level issues in the power island systems and establish the impact of systems with no transformer OLTC.
Scenario II	Anchor generator energises the 33kV network; load is taken on as the power island grows. 33/11kV transformer OLTC available when 11kV network is energised.	Identify load flow and fault level issues in the power island systems and examine to what extent the power island systems can be expanded
Scenario III	Anchor generator energises the 33kV network, then back energises to 132kV; No load is taken on.	Identifies if a backbone network can be established prior to connecting consumers. Expected to result in high voltages at the secondary side of the primary transformer (off-load energisation)

Scenario I & II (energise 33kV network, taking on load)
In scenario I, the 33/11kV primary transformer tap changers are unavailable. In scenario II, the 33/11kV primary transformer tap changers are available. For both scenarios, the anchor generator, self-starts, energises the 33kV network up to Chapelcross GSP 33kV busbars and takes on load at primary substations, as follows:

- Steven's Croft anchor generator starts up, energises the network to Annan Primary and takes on the load of this secondary group.
- Energises the network to Lockerbie Primary and takes on the load of this secondary group.
- Energises the network to Kirkbank Primary and takes on the load of this secondary group.
- Energises the network to Moffat Primary and takes on the load of this secondary group.
- Energises the network to Middlebie switching station and synchronises with Ewe Hill WF.
- Energises the network to Middlebie Primary and takes on the load of this secondary group.
- Energises the network to Langholm Primary and takes on the load of this secondary group.
- Energises the network to Newcastleton Primary and takes on the load of this secondary group.
- Energises the network to Gretna Primary and takes on the load of this secondary group.

Scenario III (energise network)
In scenario III, the anchor generator self-starts and energises the 33kV network up to Chapelcross GSP 33kV busbars. The restoration plan follows the same steps as scenarios I & II. The only variations to the previous scenarios are, 1) no load is picked up and 2) Ewe Hill WF is not required. The anchor then back energises to 132kV.

Load flow results and conclusions

In all scenarios, the restoration plan was modelled with a single anchor generator in service, Steven's Croft Biomass. The impact of the step-by-step process for each scenario is illustrated in figure 8.1, figure 8.2 and figure 8.3.

Generator MVAr limits
The "Steven's Croft MVAr" graphs show the reactive power output, measured at the terminal of Steven's Croft Biomass anchor generator. Throughout the restoration plans, scenario 3 shows the worst case reactive requirements. In this scenario, the generator needs to absorb a maximum output of 6.2MVAr at step 21.

Engineering Recommendations (ER)-G59 connected anchor generators are required to operate in a power factor range between 0.85 (lag) to 0.95 (lead). Therefore, in terms of reactive capability, an ER-G59 anchor generator with a rated capacity as low as 10 MW would be suitable to meet the range required for this scenario/network type. If connected via ER-G99 15 MW would be required, this is due to the reduced range of power factor requirement (+/- 0.92) in the new guidelines. Steven's Croft Biomass, as a 51 MW ER-G59 connected generator, is, therefore, well within its reactive range for all scenarios.

In scenarios 1 and 2, Ewe Hill wind farm was energised at step 13. This provided increased active power capability to allow for the connection of additional customers.

Voltage limits
The "Voltage Profile" graphs show the range of voltages in each stage of the case study. For the opening stages, in all scenarios, the voltage range remains narrow.

- In scenario 1 and 2, as the load is connected to the end of long rural circuits, the voltage seen at the end terminal of the circuit is much lower.
- In scenario 3, as the network is energised without picking up any block load, the reactive gain from long cable circuits pushes voltages up. At stage 8, the voltage increases above 1.06 p.u. at specific primary substations. This suggests that further steps should not be taken until voltages on the network are controlled and regulated within acceptable ranges by the connection of demand or other means.

The "Voltage Range" graph shows the range of voltages seen at selected busbars in each case study. The chart shows the maximum, minimum and average per unit voltages.

- In scenario 1, voltages are seen outside distribution code requirements of +/-6 per cent of nominal voltage, when the voltage at Steven's Croft Biomass terminals (STCR5-) remains fixed at circa 1 p.u.
- In scenario 2, the OLTC of the primary transformers is available. In this scenario, all voltages stay within distribution code requirements of +/-6 per cent of nominal voltage by utilising OLTC of primary transformers.
- In scenario 3, the results shown in the Voltage Range graph correlate with that of the Voltage Profile graph. High volts are observed at Moffat, Kirkbank and Lockerbie. These primary substations are banked together on the end of long rural circuits. The solution previously discussed, connecting load at stage 8, would mitigate these issues.

The "Voltage Step Change" graph shows the maximum and minimum voltage step change at selected busbars in each case study.

- The largest positive voltage step change is seen in scenario 1, stage 8 of the restoration process. The 9.3 per cent step change is recorded at Lockerbie Primary 11kV busbar as transformer 2 is energised, reducing the impedance between load and source.
- The largest negative voltage step changes occurred at the primary substations due to load pick-up.
- The voltage step changes recorded are within distribution code guidelines of 10 per cent for infrequent events.

Figure 8.1
Scenario I load flow results

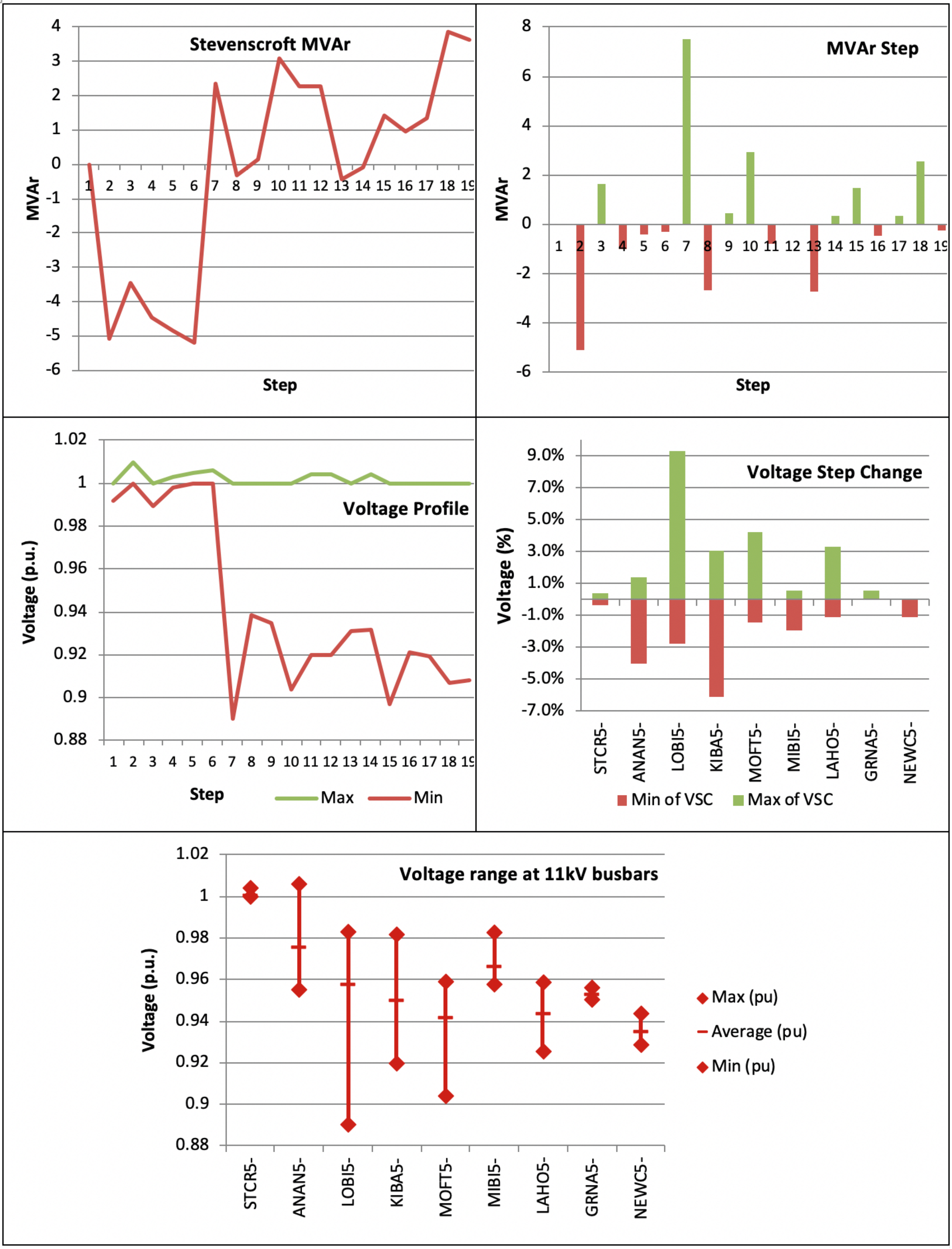


Figure 8.2
Scenario II load flow results

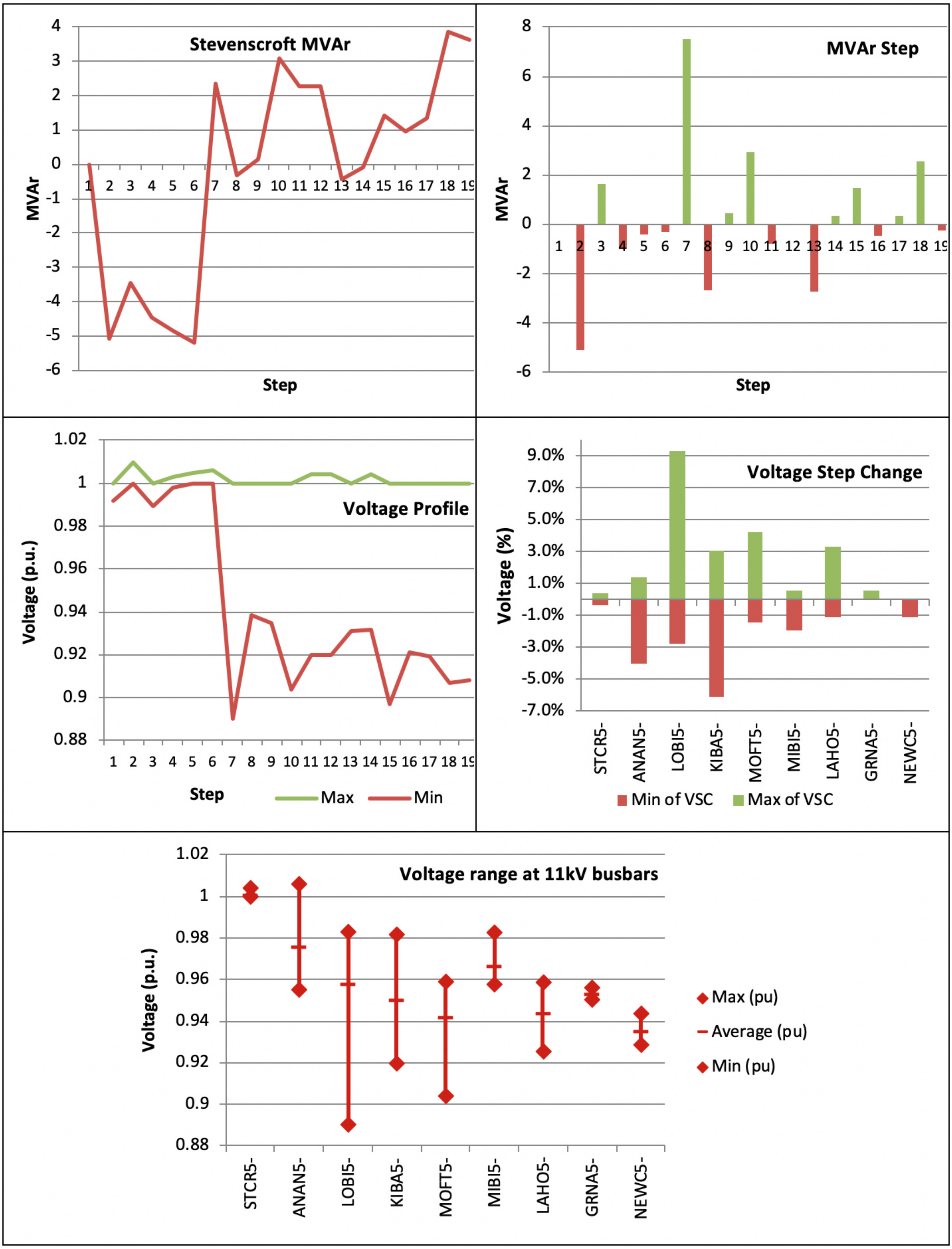
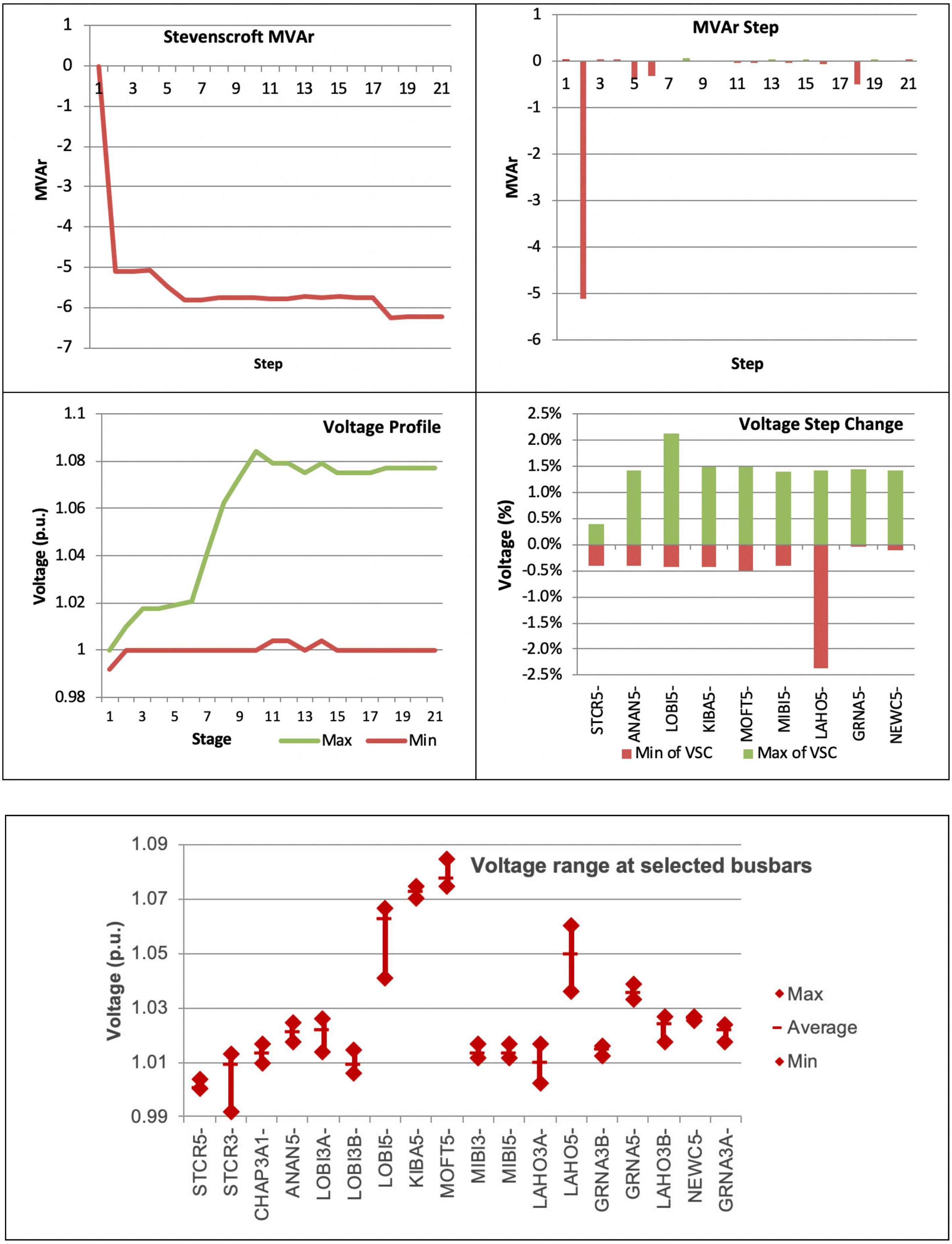


Figure 8.3
Scenario III load flow results



Fault level results and conclusions

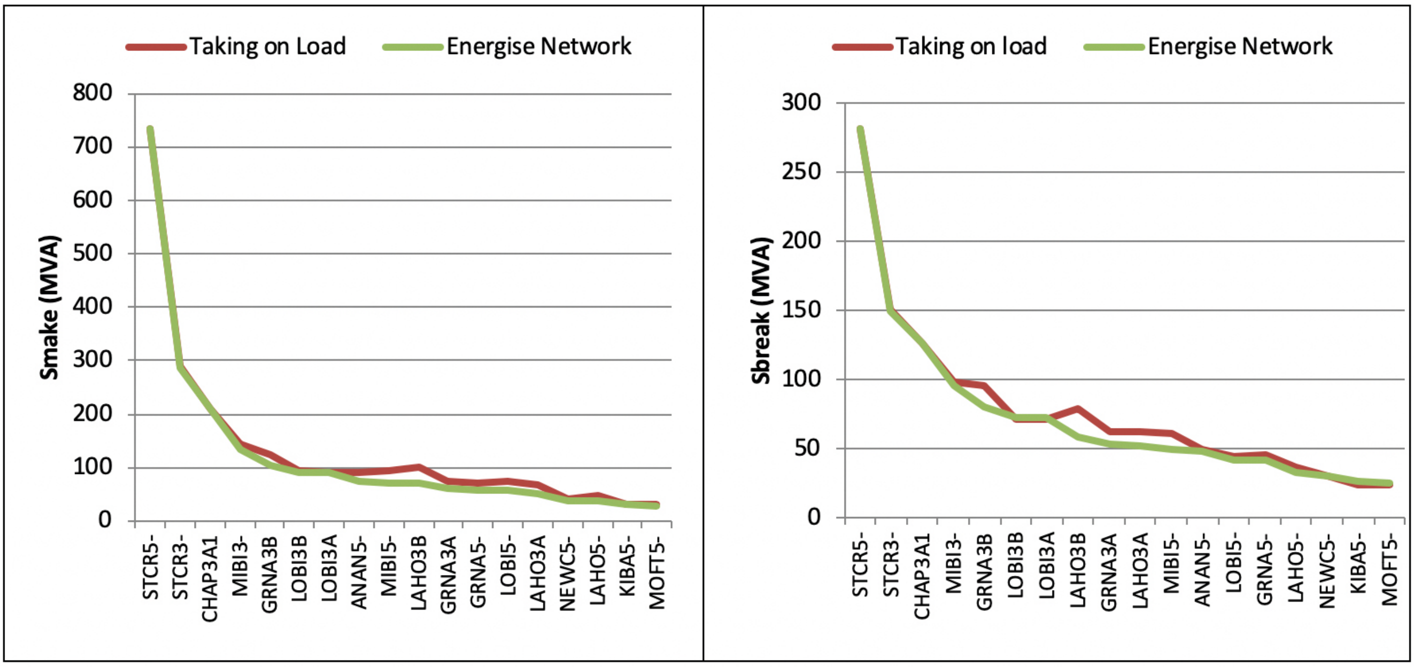
Fault level studies have been undertaken for selected scenarios and results are presented in table 8.2 and figure 8.4. The values represent the lowest values seen among all restoration steps, for each selected restoration scenario.

The lowest values are seen at the extremities of the power islands, furthest apart from the generators. The lowest values among all scenarios are seen at Moffat and Kirkbank 11kV busbars. The lowest value in an power island changes location as the restoration steps progress.

Table 8.2
The lowest fault level results in selected scenarios

Minimum values	132kV		33kV		11kV	
	Smake(MVA)	Sbake(MVA)	Smake(MVA)	Sbake(MVA)	Smake(MVA)	Sbake(MVA)
Taking on load	–	–	66.66	62.07	29.59	23.95
Energise network	108.24	69.61	52.14	52.77	28.38	25.55

Figure 8.4
Lowest value of fault levels results for restoration options



Appendix I – power system studies, SPM case studies assessment

Introduction

Steady state load flow and fault level studies were performed for the two SPM cases: **Sankey Bridges** and **Maentwrog**.

Analysis was performed in IPSA2 with processing of data and results in Excel.

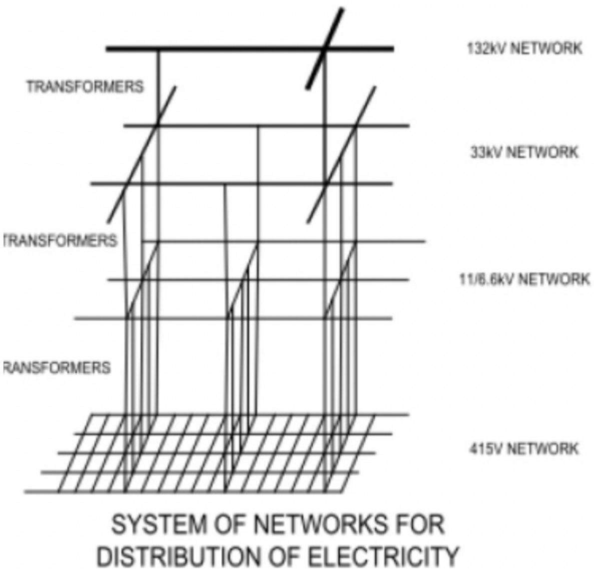
The model of the SPM Distribution System was derived from the most recent Authorised Network model to which winter peak demand and generation characteristics have been updated accordingly. This model contains the latest updates to network configuration and parameters. The 132kV and 33kV distribution network was modelled in detail, while the 11kV distribution network was represented by lumped loads connected at the lower voltage side of each 33/11kV primary transformers.

SPM network

The SP Manweb Distribution System is configured and operates at 132kV, 33kV(EHV), 11kV, 6.6kV, 6.3kV (HV), and 400/230 volts (LV), providing supply to the connection point of all remaining customers for industrial, commercial and domestic purposes.

The SPM network is significantly different from other DNOs' networks as approximately 80 per cent of the SPM network is designed, operated and extended as a meshed network with interconnection at all voltage levels. The SPM philosophy is based on high transformer utilisation, where smaller single transformer substations supply power into an interconnected mesh where standard cable sizes are used throughout. Each voltage layer provides support to the voltage layer immediately above (LV, HV, EHV and 132kV) offering a fully integrated and interconnected network.

Figure 8.5
SPM network topology (extract from SPM long term development statement November 2018)



Extra high voltage (132kV) primary Distribution System
The 132kV network is supplied from the National Grid transmission system through their 400/132kV or 275/132kV SGTs at GSP substations. The 132kV circuits interconnect and/or provide connections to BSP substations.

Extra high voltage (33kV) primary Distribution System
The SPM primary Distribution System is a group of circuits that provides supplies to primary substations and customers with an EHV point of supply. These circuits also offer the provision of emergency interconnection between BSPs. The circuits comprise sections of underground cable or overhead line (supported by steel towers or wood poles), or a combination of both. The 33kV network is supplied from the 132kV network at BSP substations utilising transformers of a standard size and vector group. Each transformer has an on-load tap changer (OLTC), which is employed with an automatic voltage control (AVC) scheme to maintain 33kV system voltages. To achieve high utilisation of the transformers, they are operated in parallel with those at other BSP substations through the interconnected 33kV network. AVC schemes employ negative reactance compounding to ensure the tap changers on each transformer remain synchronised. The AVC equipment is normally set to maintain the transformer secondary voltage within +/1.75 per cent of the nominal secondary voltage.

HV (11kV) Distribution System

The secondary Distribution System provides supplies to secondary substations and to customers with an HV connection, and also provides interconnection between primary substations. HV circuits comprise sections of underground cable or overhead line, or a combination of both. While some areas of the HV system in Merseyside continue to operate at 6.6kV and 6.3kV, the bulk of the HV Distribution System operates at 11kV.

The HV network is supplied from the 33kV network at primary substations utilising standard transformer sizes and vector groups. Each transformer has an OLTC, which is employed with an AVC scheme to maintain HV system voltages. The AVC scheme employs negative reactance compounding to ensure that the tap changers on all transformers operating in parallel remain synchronised. This ensures efficient load sharing and minimises circulating current. The AVC equipment is normally set to maintain the transformer secondary voltage within limits of +/- 1 per cent of the voltage set point. The target voltage is normally set to 11kV at the primary substation HV busbar.

Sankey Bridges case study

Sankey Bridges 33kV

This group has about 54 MW of anchor generation at the following three gas sites:

- Latchford Lane (20 MW connected)
- Warrington Power (16 MW in 2019)
- Arpley Landfill (18 MW connected).

There are no wind farms or solar parks connected at 33kV.

This is a self-sufficient group as far as minimum load is concerned and has been selected as it can provide the opportunity for Black Start in conjunction with generation connected at 132kV in Carrington area.

The Sankey Bridges case study is representative for most of the SPM network as it has a highly meshed network, including at the 11kV and LV levels in normal operation. In figure 8.6 the 33/11kV primary substations interconnected at a lower voltage level have the same symbol. In Sankey Bridges, there are five such primary groups composed of multiple primary transformers, between two and five. During restoration, overloads in the 11kV network and primary transformers may occur if open points in the 11kV and LV network are not put in place. This is discussed in more detail in the following sections.

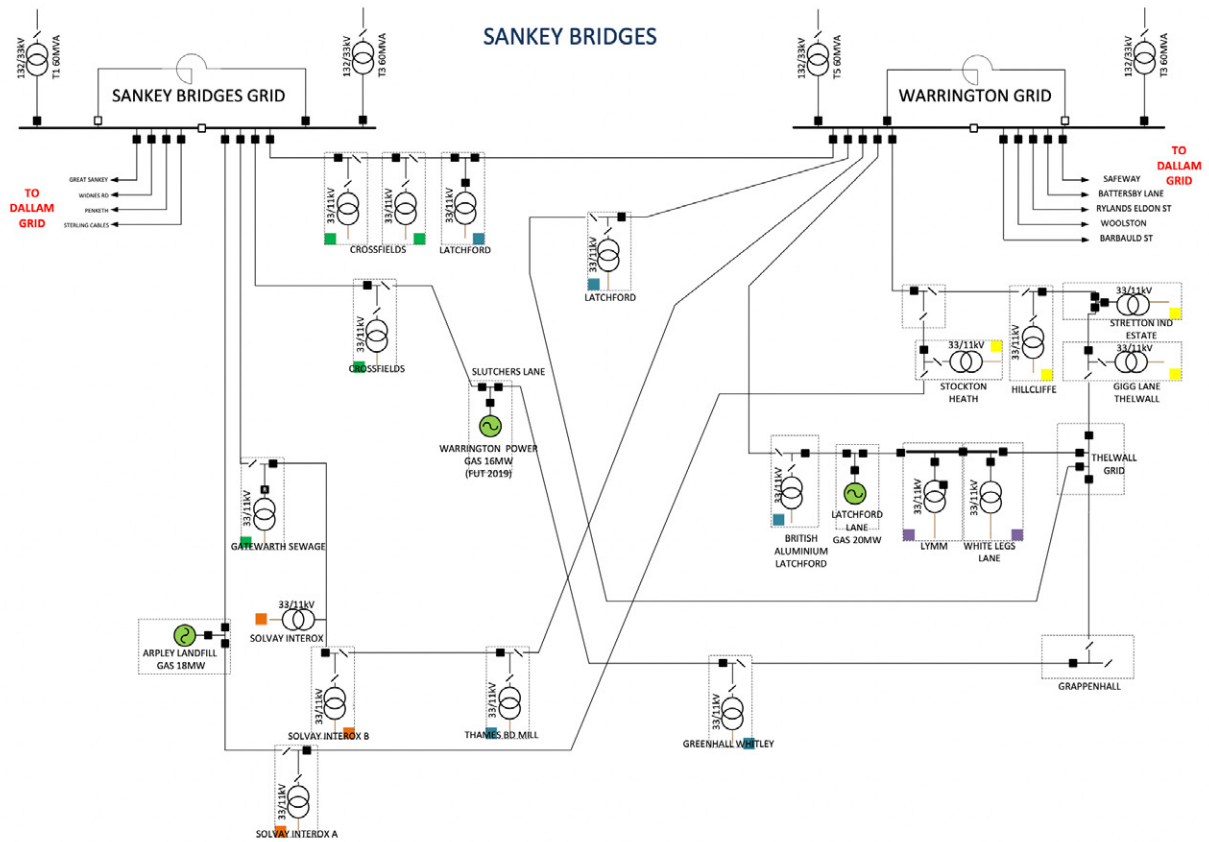
The total peak demand in the Sankey Bridges – Warrington area is 61 MW, distributed across the five primary groups. Their demand varies between 9.1 MW and 20.7 MW. All 33/11kV primary transformers have a capacity of 7.5 MVA.

Carrington 132kV

Around 138MW of anchor generation is connected to the Carrington 132kV network at CHP BM Winnington. It comprises of GT1 40MW, GT2 40 MW and ST 58.1 MW. Only GT1 has been considered in the studies.

The minimum load demand in the combined Carrington-Fiddlers Ferry 33kV and 132kV network is about 96MVA. This Supergrid group feeds the Sankey Bridges area via two 60 MVA transformers, one in Sankey Bridges Grid and one in Warrington Grid.

Figure 8.6
Sankey Bridges 33kV schematic (coloured symbols indicate interconnection at lower voltage level)



Maentwrog case study

This group has about 39.8 MW of anchor generation, with an additional 46 MW of solar and wind generation. The generation sites considered in the studies are:

- Maentwrog Hydro G1 and G2 (29.6 MW connected)
- Cwm Dyli Hydro (10.2 MW connected)
- Nefyn PV Solar Park (8 MW connected).

This group also has a lot of excess generation compared to the minimum load of 8.2 MVA. This group has been selected due to the long rural lines.

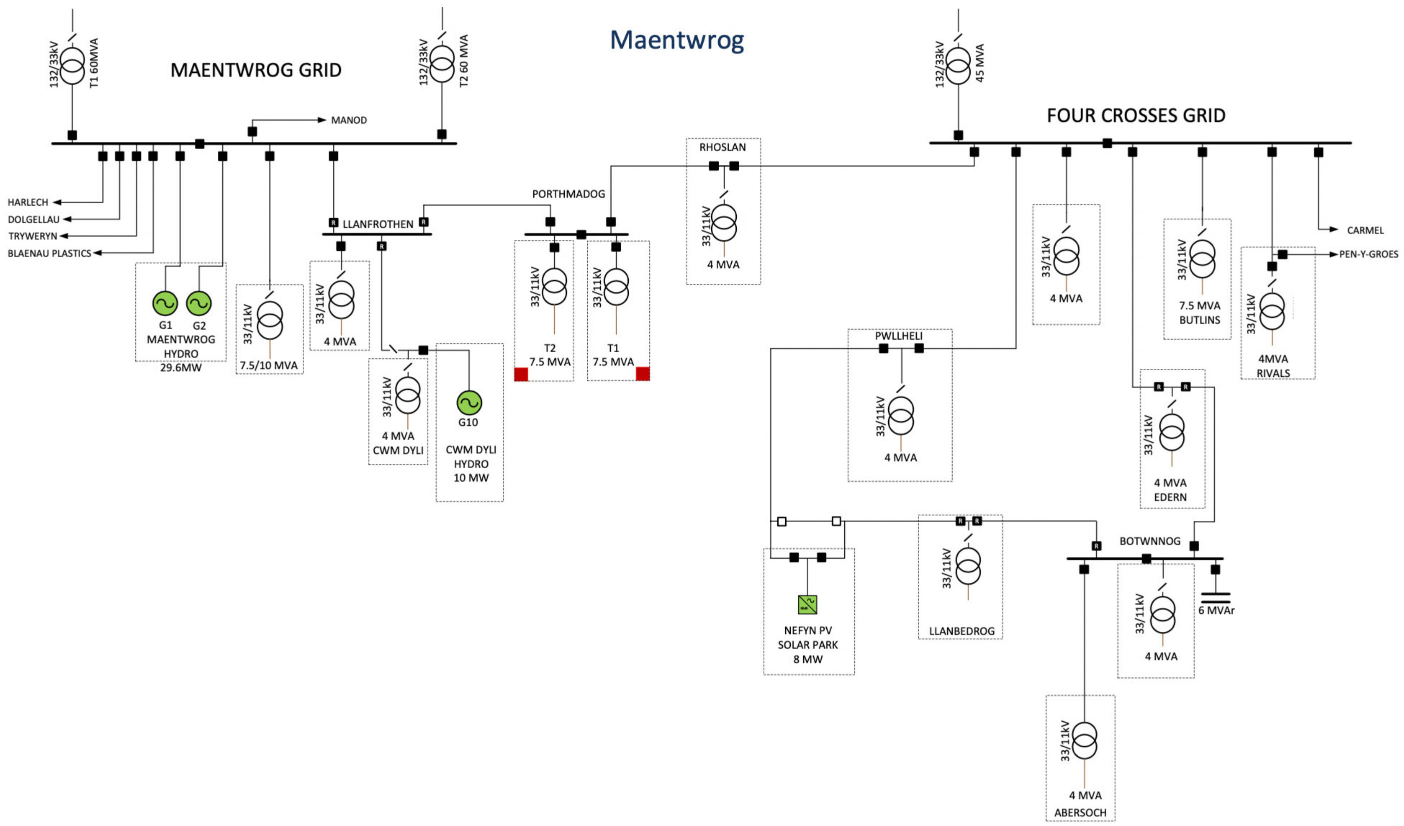
The 11kV network in Maentwrog is radial, with the exception of Porthmadog primary group whose interconnectivity is shown via a symbol in **figure 8.7**.

All 33/11kV primary transformers have a capacity of 4 MVA, with Maentwrog Grid (7.5/10 MVA) and Porthmadog primary (7.5 MVA) being the two exceptions.

This group is fed from Trawsfynydd Supergrid group via two 60 MVA transformers in Maentwrog Grid.

Figure 8.7

Maentwrog Grid 33kV Schematic (coloured symbols indicate interconnection at lower voltage level)



Assumptions and modelling

The network model was prepared for the Black Start analysis by making the changes in accordance with the assumptions below.

Generator assumptions and modelling

- The anchor generation sites in the Sankey Bridges 33kV group consist of multiple 2 MW generators. For the purpose of the studies, each generation site has been modelled as a lumped equivalent generator connected at 11kV, via a 33/11kV transformer.
- The minimum power output of the generators has been ignored at this stage. It is expected that this information will be taken into consideration in the detailed power system studies during the design stage of the project.
- As the purpose of these high-level studies is to identify the worst-case scenarios in terms of voltage profile and MVAr step change, it has been assumed that the generators are able to provide block loading close to their capacity. Detailed studies in the design stage will be used to identify the limitations of generators to pick up block loads based on generators' inertia, reactive power capability, AVR and governor characteristics.
- The auxiliary load demand of generators has not been taken into account.
- Assumed continuous fuel (gas, hydro, solar) availability.
- A power factor range of 0.85 lag (reactive power export) to 0.95 lead (reactive power import) has been considered at the terminals of the 11kV anchor generators.
- 1.p.u. voltage setpoint at the 11kV terminals of the anchor generators was considered.
- 1 p.u. voltage setpoint at the 33kV terminals of the 33/11kV generator transformers was applied.
- The additional DER operated at unity constant power factor (no reactive power exchange with the network).
- The generators connected directly to the 11kV network have not been considered.
- The contribution of the motors has not been considered in the fault level studies, as a conservative assumption.

Network operation assumptions and modelling

- Normal operation was assumed prior to Black Start, e.g. all transformers and lines connected as per normal operation.
- All 132kV, 33kV and 11kV circuit breakers open prior to restoration; all disconnectors closed.
- All transformer taps locked on the positions corresponding to the normal operation prior to blackout. These taps have been considered fixed throughout restoration, as a conservative assumption.

Block loading and network connectivity

It is likely that the minimum demand that can be connected at any one time will be that of a primary 33/11kV substation, to ensure that the number of switching operations and the associated time are not excessive. The load fed by a primary substation is taken on by closing the 11kV circuit breaker of the primary transformer which will automatically energise all the 11kV feeders connected to that primary substation.

In the system studies, the smallest block loads are equal to the winter peak loads of the 33/11kV primary transformers.

As discussed in the previous section, the Sankey Bridges case study is representative for most of the SPM network as it has a **highly meshed network**, including that at the 11kV and LV levels in normal operation. The transformers in a primary group share the same interconnected network at a lower voltage level. During restoration, overloads in 11kV network and primary transformers may occur if open points in the 11kV and LV network are not put in place. Consequently, the largest block loads are equal to the total load of a primary group in the scenario in which it is considered not practical to split the interconnected network at lower voltages.

Description of the restoration scenarios

The network system studies have been undertaken across five scenarios: four in Sankey Bridges and one in Maentwrog. The studied scenarios are combinations of the various restoration alternatives described in table 8.3.

Restoration alternatives	Description	Scope	Scenarios
Anchor generators create 33kV individual power islands	**Sankey Bridges:** Each of the three 33kV anchor generators creates a 33kV power island	Identify load flow and fault level issues in the power island systems and examine to what extent the power island systems can be expanded	Scenario I.a Scenario I.b Scenario I.c
One anchor generator initiates the Black Start to form an power island, energise 33kV network and other generators and create a shared power island	**Sankey Bridges:** Latchford Lane anchor generator initiates Black Start and energises the other two generators in the area while taking on load as the power island grows. Generators share the same 33kV power island, which covers four out of the five primary groups	Identify load flow and fault level issues in the power island systems and examine to what extent the power island systems can be expanded	Scenario II
	Maentwrog: Maentwrog anchor G1 initiates Black Start and energises the other generators (Maentwrog G2, Cwm Dyli, Nefyn PV) in the area while taking on load as the power island grows. Generators share the same 33kV power island, which extends from Maentwrog Grid to Four Crosses Grid and Botwnnog – Abersoch primary substations	Specifically, for **Maentwrog:** identify voltage issues in the context of long rural lines	Scenario V
Bottom to top restoration from a 33kV anchor generator	**Sankey Bridges:** Latchford Lane anchor generator initiates Black Start, energises the 33kV network up to Warrington Grid, energises T5 132/33kV transformer, the 132kV network up to the BM Winnington GT1 40MW, which is further used to feed the demand in Sankey Bridges 33kV network	Identify if the 33kV anchor generator has sufficient reactive power capability to energise the 132kV network and BM Winnington GT1	Scenario IV
Primary substations share the same interconnected network (known as group) at lower voltages in normal operation. The 11kV & LV highly meshed group not practical to be split	**Sankey Bridges:** The full demand of a primary group is connected as one block load. Studied by energising all primary transformers in a group first and then simultaneously closing all the corresponding 11kV transformer circuit breaker to take on the primary group load **Maentwrog:** Mostly radial, not applicable	Expected to show the largest voltage and MVAr step changes. This scenario has been studied in the event in which further detailed analysis will show that such primary groups cannot be practically split to allow for energisation of smaller block loads.	Scenario I.a Scenario I.b Scenario I.c Scenario II Scenario IV
Primary substations share the same interconnected network (known as group) at lower voltages in normal operation. The 11kV & LV highly meshed network in a group can be split	**Sankey Bridges:** A primary substation within a group and its corresponding load can be energised independently from the rest the primary substations within the same group. **Only** in this scenario, the load is assumed to be taken on simultaneously with the primary transformer (11kV circuit breaker of the 33/11kV transformers maintained closed prior to Black Start initiation) **Maentwrog:** Mostly radial, not applicable	Confirmation of the practicality of splitting the 11kV & LV highly meshed network requires further detailed analysis	Scenario III

Restoration alternatives	Description	Scope	Scenarios
The anchor generator energises the backbone network of the power island first (including primary transformers), and then the load is taken on	Note: In most cases, due to the location of circuit breakers, the primary transformer is energised together with a 33kV circuit	Identifies if a backbone network can be established prior to connecting consumers. Expected to result in higher voltage profile compared with the scenario below	Scenario I.b Scenario I.c
The load is taken on as the power island grows	**Sankey Bridges:** The load is taken on following the energisation of the primary transformer	Identify load flow and fault level issues in the power island systems and examine to what extent the power island systems can be expanded	Scenario I.a Scenario II Scenario IV
	Sankey Bridges: The load is taken on simultaneously with the primary transformer (11kV circuit breaker of the 33/11kV transformers can be maintained closed prior to Black Start initiation)		Scenario III
	Maentwrog: The load is taken on following the energisation of the primary transformer		Scenario V

Table 8.3
Description of various restoration alternatives and studied scenarios

Scenarios I.a, I.b, I.c (Sankey Bridges)
In Sankey Bridges, 33/11kV primary substations share the same interconnected network (known as group) at lower voltages in normal operation, as depicted in figure 8.6. In all scenarios I, it is assumed that the 11kV and LV highly meshed network within a group is not practical to be split; the following steps have been considered:

- energise the network step by step to incorporate those primary substations (including transformers) which are part of the same primary group
- take on the load of the group by simultaneously closing all the corresponding 11kV transformer circuit breakers within the group
- continue the restoration by moving to the next group.

In scenarios I, each generator in Sankey Bridges area creates a separate 33kV power island, as follows:

- Latchford Lane anchor generator starts-up, energises the network up to Lymm & Whiteleggs Lane primary substations, take on the load of this group, and then energises the network up to Warrington Grid 33kV, via British Aluminium Latchford primary;
- Warrington Power anchor generator starts-up and energises the network up to Crossfields & Gateworth Sewage primary substations, energises the network up to Sankey Bridges Grid 33kV, and then take on the load of Crossfields & Gateworth Sewage group.
- Arpley Landfill anchor generator starts-up and energises the network up to Solvay Interox primary substations, energises the network up to Sankey Bridges Grid 33kV, and then take on the load of Solvay Interox group.

For each of the 3 scenarios, these generators cannot take on demand from other groups, as the addition of any other group demand would exceed the generator capacity.

Scenario II (Sankey Bridges)
In Sankey Bridges, 33/11kV primary substations share the same interconnected network (known as group) at lower voltages in normal operation, as depicted in figure 8.6. In all scenarios II, it is assumed that the 11kV and LV highly meshed network within a group is not practical to be split; the following steps have been considered:

- energise the network step by step to incorporate those primary substations (including transformers) which are part of the same primary group
- take on the load of the group by simultaneously closing all the corresponding 11kV transformer circuit breakers within the group
- continue the restoration by moving to the next group.

In scenario II, one anchor generator self-starts and energises the network to form a power island before picking up the other two generators in the area and creating a 33kV shared power island, as follows:

- Latchford Lane anchor generator starts-up to form an power island, energises the network up to Lymm and Whiteleggs Lane primary substations and then take on the load of this group
- Energises the Warrington Power generator via Thelwall Grid – Grappenhall – Greenhall Whitley circuit
- Energise Greenhall Whitley, British Aluminium Latchford, Latchford and Thames Board Mill primary substations and then takes on the load of this group
- Energise Crossfields & Gateworth Sewage primary substations and then takes on the load of this group
- Energise the Arpley Landfill generator via Sankey Bridges Grid
- Energise Solvay Interox group primary substations and then takes on the load of this group.

The Warrington Power and Arpley Landfill generators were connected when the generating capacity in the power island was not sufficient to take on more demand.

Scenario III (Sankey Bridges)
In Sankey Bridges, 33/11kV primary substations share the same interconnected network (known as group) at lower voltages in normal operation, as depicted in figure 8.6. Only in this scenario it has been assumed that the 11kV and LV network in a group can be split prior to restoration such that the load corresponding to each primary transformer within the same group can be taken on independently from the rest of the group demand.

Moreover, the load is assumed to be taken on simultaneously with its primary transformer, rather than in a subsequent step following transformer energisation.

In this scenario, the anchor generator in the power island picks-up smaller block loads as follows:

- Latchford Lane anchor generator starts-up to form an power island, energises the network up to Lymm primary substation and takes on the load; energises the network up to Whiteleggs Lane primary substation and takes on the load
- then energises the network up to Hillcliffe and Stretton Ind Estate primary substations and takes on the load
- the load is taken on simultaneously with its corresponding primary transformer.

Scenario IV (Sankey Bridges)
In Sankey Bridges, 33/11kV primary substations share the same interconnected network (known as group) at lower voltages in normal operation, as depicted in figure 8.6. In all scenarios IV, it is assumed that the 11kV and LV highly meshed network within a group is not practical to split; the following steps have been considered:

- energise the network step by step to incorporate those primary substations (including transformers) which are part of the same primary group
- take on the load of the group by simultaneously closing all the corresponding 11kV transformer circuit breakers within the group
- continue the restoration by moving to the next group.

A bottom up restoration is studied, with Latchford Lane anchor generator energising part of 33kV and 132kV network up to BM Winnington G1 generator which further contributes to the growth of the 33kV Sankey Bridges power island. The steps are as follows:

- Latchford Lane anchor generator starts-up to form an power island, energises the network up to Lymm and Whiteleggs Lane primary substations and then take on the load of this group
- energises the network up to the Warrington Grid 33kV bus and Warrington T5 132/33kV transformer
- energises the 132kV network up to the BM Winnington G1 generator via Warrington – Carrington – Knutsford – Lostock-ICI Wade 132kV substations
- energises BM Winnington G1 generator
- energise Warrington – Sankey Bridges 132kV circuit and Sankey Bridges T3 132/33kV transformer to create a second infeed from the 132kV network for the Warrington – Sankey Bridges 33kV
- energise the rest of the Sankey Bridges – Warrington group and restore demand in four out of the five primary groups.

A third generator would need to be connected in order to restore the full Sankey Bridges – Warrington group demand. Note: The 132kV route from Warrington to BM Winnington has been selected based on the minimum reactive gain being exhibited by the circuit.

Scenario V (Maentwrog)
The Maentwrog 11kV and LV network is radial, with the exception of Porthmadog primary group whose interconnectivity is shown via a symbol in figure 8.7. The scenario included the following steps:

- Maentwrog Hydro generator G1 starts-up to form an power island, energises the Maentwrog Grid and takes on the load
- energises Llanfrothen, Porthmadog and Rhoslan primary substation and taking on the load as the power island grows
- energises Maentwrog Hydro generator G2 to increase generating capacity in the area
- energises Four Crosses substation and taken on the load
- increase Maentwrog Hydro G1 and G2 voltage setpoint to 1.03 p.u. to avoid exceedance of the voltage lower limit in Four Crosses area
- energises part of Four Crosses grid and take on load as the power island grows
- further increase Maentwrog Hydro G1 and G2 voltage setpoint to 1.05 p.u. to avoid exceedance of the voltage lower limit (0.94 p.u.) in Four Crosses area
- connect Botwnnog 6MVAr capacitor bank for the same purpose as above
- energise Cwm Dyli hydro generator to mitigate thermal overloads seen on the Maentwrog Grid – Llanfrothen 33kV circuit
- energise Nefyn PV in order to take expand the power island to Abersoch, Llanbedrog, Pwllheli and Butlins primary substations.

Load flow results and conclusions

Selected voltage profile and MVAr results are shown in figure 8.8 to figure 8.11, for each restoration step and for each busbar or node in the network model. A summary of the conclusions is shown in table 8.5.

Generator MVAr limits
In all scenarios, none of the anchor generators reaches its MVAr limits. These limits have been considered based on a power factor range of 0.85 lag (reactive power export) to 0.95 lead (reactive power import) at the generator 11kV terminals.

In the Sankey Bridges scenarios, the largest steps in MVAr are seen when the load is taken on or when other generators are energised. For Maentwrog (scenario V), the largest MVAr steps are seen when generators voltage setpoints are being increased.

In Scenario IV (Sankey Bridges), for the chosen restoration route from the 33kV Latchford Lane anchor generator towards the 132kV BM Winnington site, the 33kV anchor generator was capable of compensating the reactive gain of the 132kV network. However, this would not have been the case for the other alternative 132kV routes due to the reactive gain of these circuits.

Voltage limits
The results have shown that voltages are generally well within the statutory -6/+6 per cent limits with the exception of:

- scenario IV (Sankey Bridges)
  – The voltage at two 11kV primary buses slightly exceeds 1.06 p.u. for a reduced number of restoration steps, until the group load is taken on
- scenario V (Maentwrog)
  – The voltage at the Botwnnog 33kV (location of the capacitor bank) slightly exceeds 1.06 p.u. for one restoration step
- scenario V (Maentwrog)
  – The voltage at one bus located at the furthest end from the anchor generator reached 0.93 p.u. at one restoration step, before generators increased the voltage setpoint.

It should be noted that the transformer taps were locked during all the restoration steps. Moreover, except for scenario V (Maentwrog), the voltage setpoint of anchor generators was maintained at 1 p.u. throughout the restoration process. This suggests that for the restoration scenarios studied, there is more room for improving the voltage profile.

In scenario V (Maentwrog), the reactive capability of anchor generators and existing capacitor bank were used to mitigate voltage drops across long 33kV lines.

Voltage step change limits
The voltage step changes are well within distribution code guidelines of 10 per cent for infrequent events.

In Sankey Bridges scenarios, the negative voltage step changes are consistently larger than the positive ones. The largest negative change generally occurs at the primary substations due to load pick-up. The smaller voltage step changes are seen in Scenario III when smaller block loads are being taken on (assumes the highly meshed primary groups can be split).

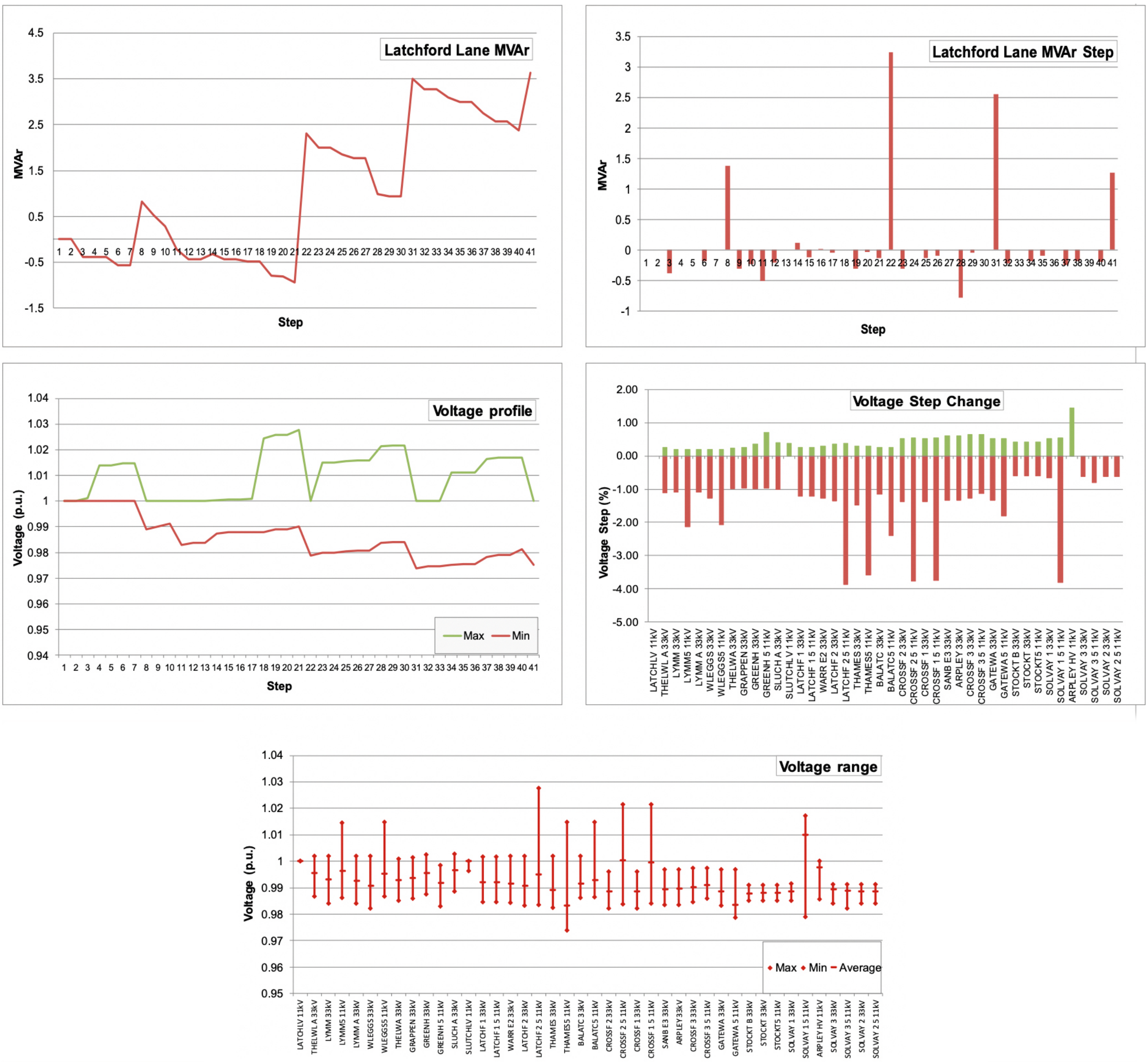
In scenario V (Maentwrog), the positive voltage step changes are generally slightly higher than the negative ones. The largest negative change generally occurs at the primary substations due to load pick-up. The largest positive change occurs when the capacitor bank in Botwnnog is switched-on or when generators increase their voltage setpoint.

Thermal overloads
In scenario V (Maentwrog), the synchronous generators located in Maentwrog and Cwm Dyli cannot supply the entire demand in Four Crosses – Botwnnog – Abersoch area due to overloads on the Maentwrog – Llanfrothen – Porthmadog 33kV long circuits. The Nefyn Solar Park 8 MW, assuming full solar energy availability, aids the anchor generators to feed the demand in the Four Crosses – Botwnnog – Abersoch area.

Advantages and disadvantages of the various restoration scenarios, together with initial thoughts on how to improve system performance in system restoration are summarized in table 8.5.

Scenario II results (Sankey Bridges)

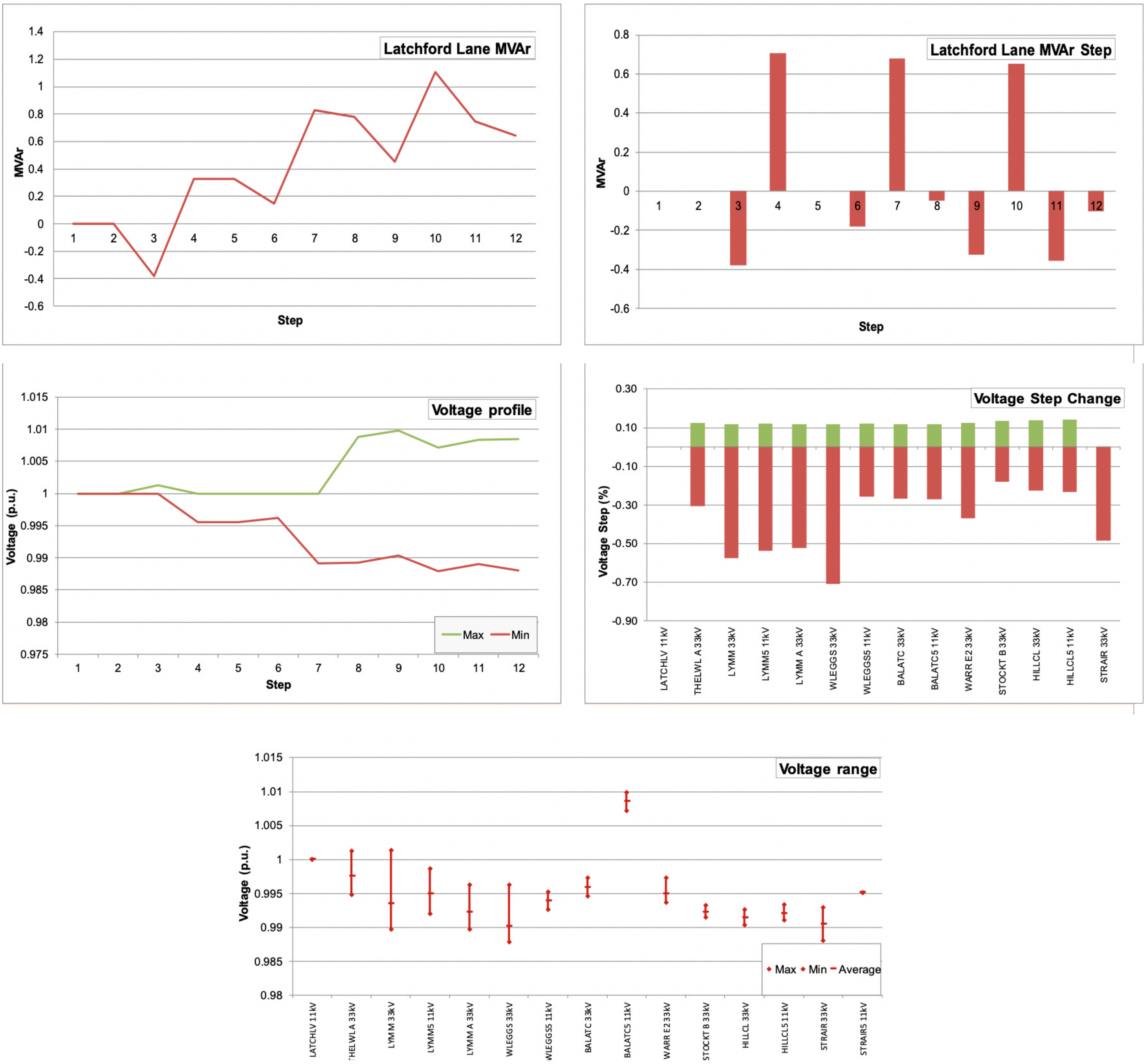
Figure 8.8
Scenario II load flow results



Note: Warrington Power 16 MW and Arpley Landfill 18 MW generators load flow results not shown.

Scenario III results (Sankey Bridges)

Figure 8.9
Scenario II load flow results



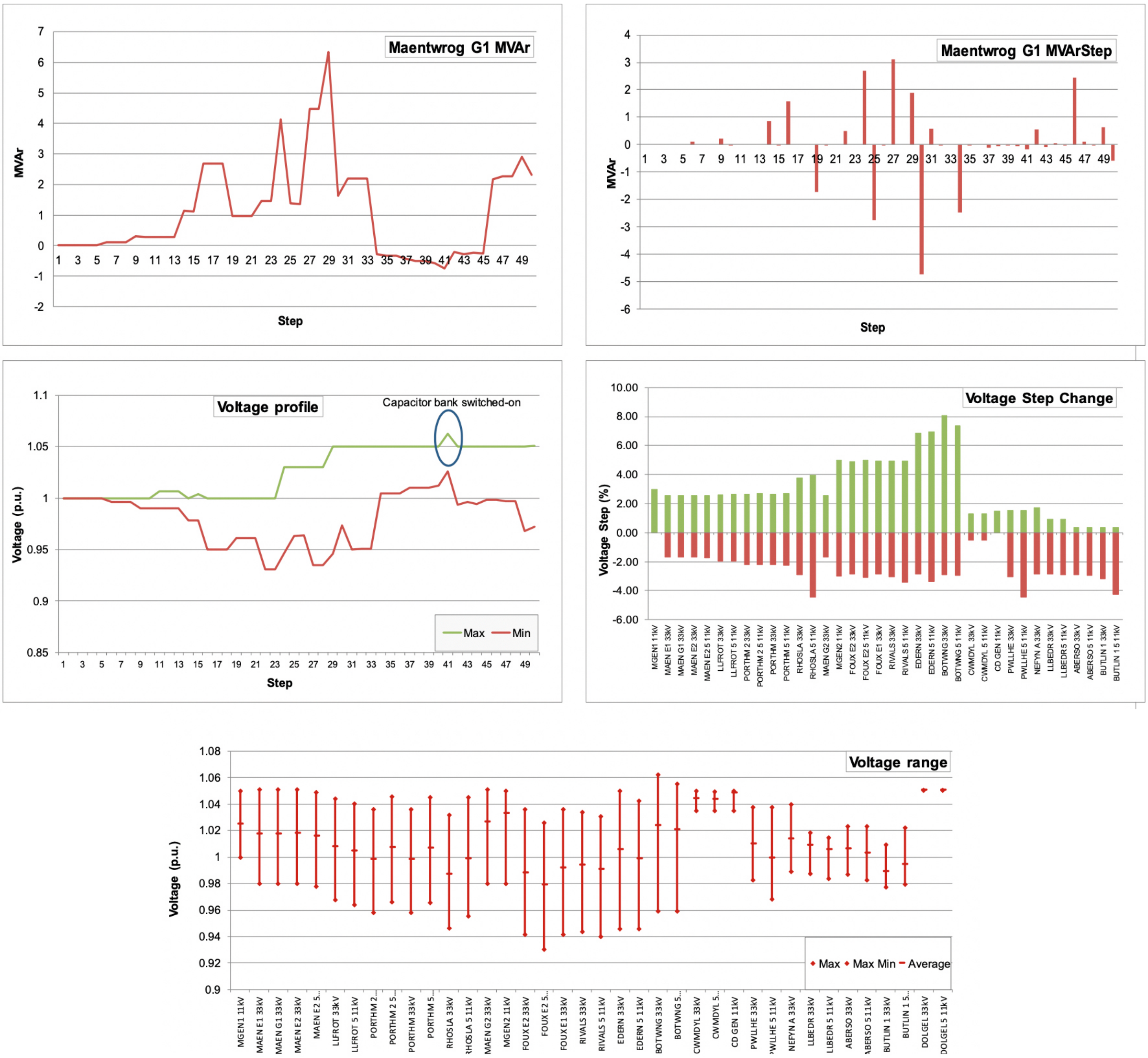
Scenario IV results (Sankey Bridges)

Figure 8.10
Scenario IV load flow results

Note: BM Winnington G1 generator load flow results not shown.

Scenario V results (Maentwrog)

Figure 8.11
Scenario V load flow results



Note: Cwm Dyli generator load flow results not shown.

Table 8.4
Summary of load flow results

Case study	Scenarios	Voltage issues				Thermal limits issues	Other
		Min value (p.u.)	Max value (p.u.)	Voltage step change	Comments		
Sankey Bridges	Scenario I.a	0.97	1.03	-2.1%	Voltage limits within +/-6% limits. Voltage step changes within +/¬-10 limits and generally occur at the primary substations due to load pick-up.	n/a	
	Scenario I.b			-5.3%			
	Scenario I.c			-5.5%			
	Scenario II	0.97	1.03	-3.8%			
	Scenario III	0.98	1.01	-0.7%			
	Scenario IV	0.94	1.06	-6.1%	1.06 p.u. occurs at two 11kV buses at a number of restoration steps. The voltage reduces in the next restoration step when load is taken on. The largest voltage step changes are within 10 per cent limits and generally occur at the primary substations due to load pick-up.	n/a	For the chosen restoration route from the 33kV anchor generator towards the 132kV BM Winnington site, the 33kV anchor generator was capable of compensating the reactive gain of the 132kV network. However, this would not have been the case for all alternative routes due to the reactive gain of these circuits
Maentwrog	Scenario V	0.93	1.06	+8.1%	The max voltage value and the largest voltage step change occur at the Botwnnog 33kV (location of the capacitor bank). Voltage recovers in the next restoration step when load is taken on in the area. The min voltage value occurs at the furthest end from the anchor generator in the power island and especially due to the long 33kV lines. The largest voltage step changes also occur due to load pick-up and generators increasing voltage setpoint.	In this scenario, the anchor generators located in Maentwrog and Cwm Dyli cannot supply the whole demand in Four Crosses – Botwnnog – Abersoch area due to overloads on the Maentwrog – Llanfrothen – Porthmadog 33kV circuits. The Nefyn Solar Park 8 MW, assuming full solar energy availability, helps extending the power island.	The Four Crosses – Botwnnog – Abersoch area experienced low voltages due to long circuits. This issue has been improved by: – increasing the voltage set point from 1p.u. (at the Black Start initiation) to 1.05 p.u.to increase utilisation of the generator reactive power capability – switching-on the existing 33kV capacitor bank at Botwnnog primary.

Fault level results and conclusions

Three phase fault level studies have been undertaken for selected scenarios. Figure 8.12 shows the range of fault levels at all busbars within the power island network, ordered from the highest to lowest fault capacity value. Fault levels are significantly lower than on a normal intact full SPM system. The lowest values are seen at the nodes of the power islands which are furthest away from the anchor generators.

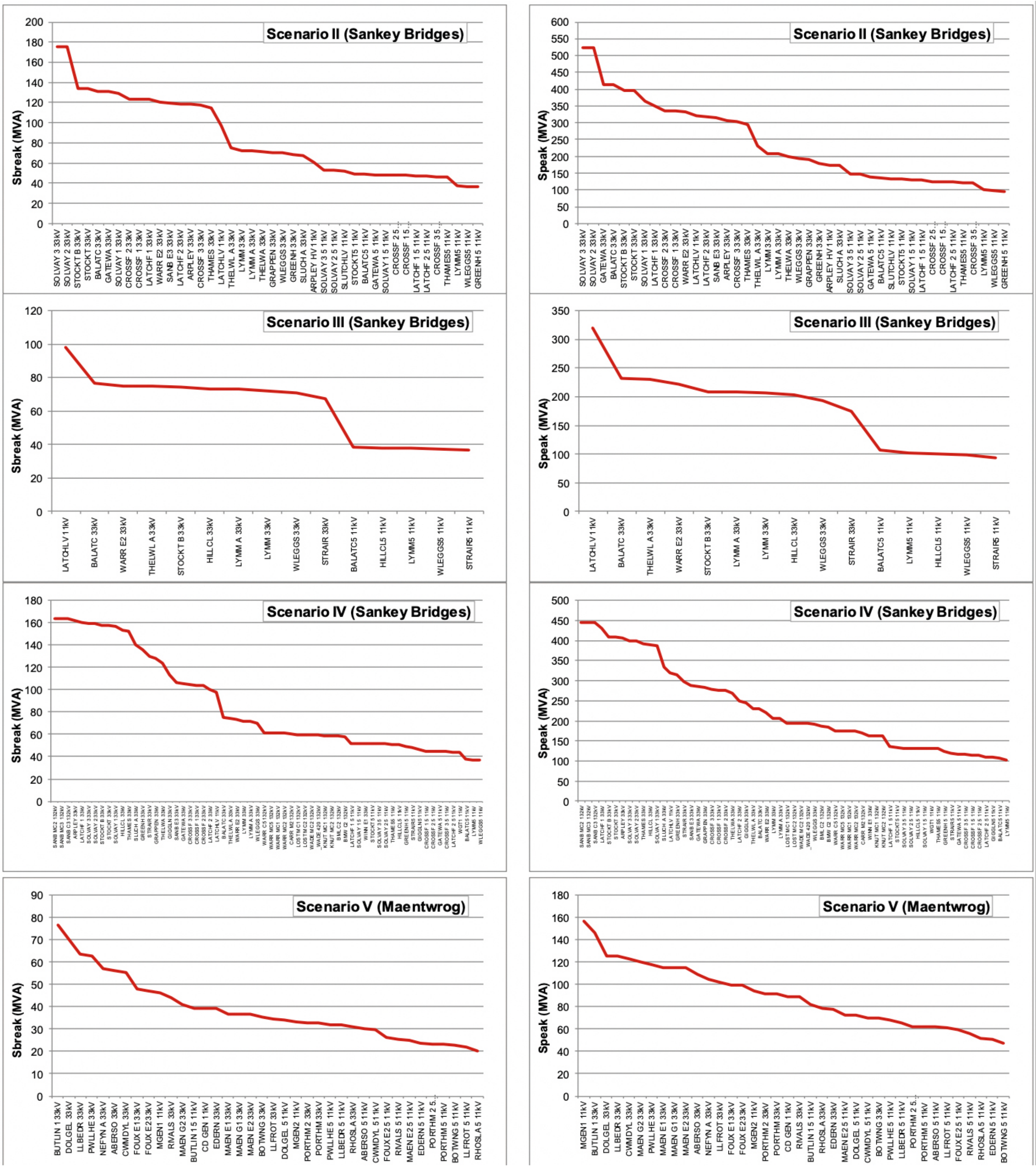
In Sankey Bridges, the lowest RMS break fault level is:

- 58 MVA at 132kV (only in Scenario IV)
- 51.3 MVA at 33kV
- 36.3 MVA at 11kV (low voltage side of a primary transformer).

In Maentwrog, these values are much lower, at 30.9MVA for 33kV and 20.3MVA for 11kV networks.

Figure 8.12

Fault levels results



Conclusions

Table 8.5 shows the advantages and disadvantages of each restoration alternative, based on the results of the system studies and research.

Table 8.5
Restoration alternatives conclusions

Restoration alternatives	Advantages	Disadvantages	Ways to mitigate disadvantages
Anchor generators create 33kV individual power islands.		All generators required to meet the technical capability specified for an anchor. Requires multiple synchronisation points to form a shared power island. Managing multiple anchors in the same area may imply higher volume of communication.	
One anchor generator initiates the Black Start to form an power island, energise 33kV network and other generators and create a shared power island.	Only one generator in the area is required to meet technical requirements specified as anchor.	The power island relies on the resilience of one generator in performing successfully as the anchor.	For each case study, the advantages of increased reliability due to multiple anchors need to be balanced with the Black Start services cost for anchors.
Bottom to top restoration from a 33kV anchor generator.	Quick restoration of power supply to part of customers.	The generator may not be capable of energising the 132/33kV transformer and the 132kV circuits. The size and capability of the 33kV anchor limits the size of the 132kV network area.	Energise as many 33kV generators in the area prior to energising the 132kV network for the purpose of provision of sufficient fault level and reactive power capability in the power island system.
Primary substations share the same interconnected network (known as group) at lower voltages in normal operation. The 11kV and LV highly meshed group not practical to be split.	Avoids establishing complex plans of splitting the 11kV and LV network.	Anchor generators may not be technically capable of picking up the total demand of the group as one block load (min. 9.1 MW, max 20.7 MW in Sankey Bridges) without exceeding the operating parameters (f, U). Requires simultaneous operation of multiple 11kV circuit breakers in one group.	The energisation of multiple generators prior to connecting large block loads reduces the impact on generators, but may not be sufficient. Load banks installed at anchor generator sites to compensate for the connection of large block loads (load banks programmed to switch out at the moment of taking on block loads).

Table 8.5 continued
Restoration alternatives conclusions

Restoration alternatives	Advantages	Disadvantages	Ways to mitigate disadvantages
Primary substations share the same interconnected network (known as group) at lower voltages in normal operation. The 11kV and LV highly meshed network in a group can be split.	The generator picks-up smaller block loads, consistent with the rating of each primary transformer	Need to establish complex plans for splitting the 11kV and LV network. Confirmation of its practicality requires further detailed analysis	
The anchor generator energises the backbone network of the power island first (including primary transformers), and then the load is taken on.	Suitable for the strategy in which a backbone network is established to synchronise with other power islands or energise transmission network first as the required priority.	May result in high voltages due to the reactive gain of long OHL and cable circuits. May result in high voltages at the secondary side of the primary transformers (off load energisation), depending on the position of the tap prior to blackout. Requires to take on a minimum load consistent with the generator minimum MW output capability.	Energise as many generators in the area for sufficient reactive power range. Bank loads installed at anchor generator sites, consistent with the generator minimum active power.
The load is taken on as the power island grows.	Suitable for the strategy in which the priority consists of feeding the consumers. If the load is taken on simultaneously with the primary transformer, then 11kV circuit breaker of the 33/11kV transformers can be maintained closed prior to Black Start initiation.	If the load is taken on simultaneously with the primary transformer, the consumers may see low voltage values during transformer energisation.	

Appendix J – transformer energisation studies

Introduction

Transformer energisation (inrush) studies were undertaken to examine voltage dips at concerned substation busbars when a primary (33/11kV) transformer is energized in the power island initiated by a 33kV anchor generator.

Energisation of the transformer has adverse effect on normal operation of the network. When a transformer is energised, it may draw a large transient current from the sources, resulting in a temporary voltage dip on the network. The voltage dip is dependent upon the magnitude of the transformer inrush current, the strength of the network, remnant flux on the transformer, and the point-on-wave (POW) circuit breaker switching time.

As the network in a power island is much weaker, in terms of the strength of the network represented by fault levels, than the network supplied by a bulk power system, voltage dips resulted from transformer energisation is considered a concern.

The network topology, circuit and transformer specification, and distributed generation capacity in the Chapelcross GSP case study were considered as a base case for the studies. The studies assessed the impact of energisation of one 33/11kV transformer at Annan primary substation, normally supplied by Chapelcross GSP, on voltage dips in the power island initiated by a 45 MW distributed generator located at Steven's Croft (11kV).

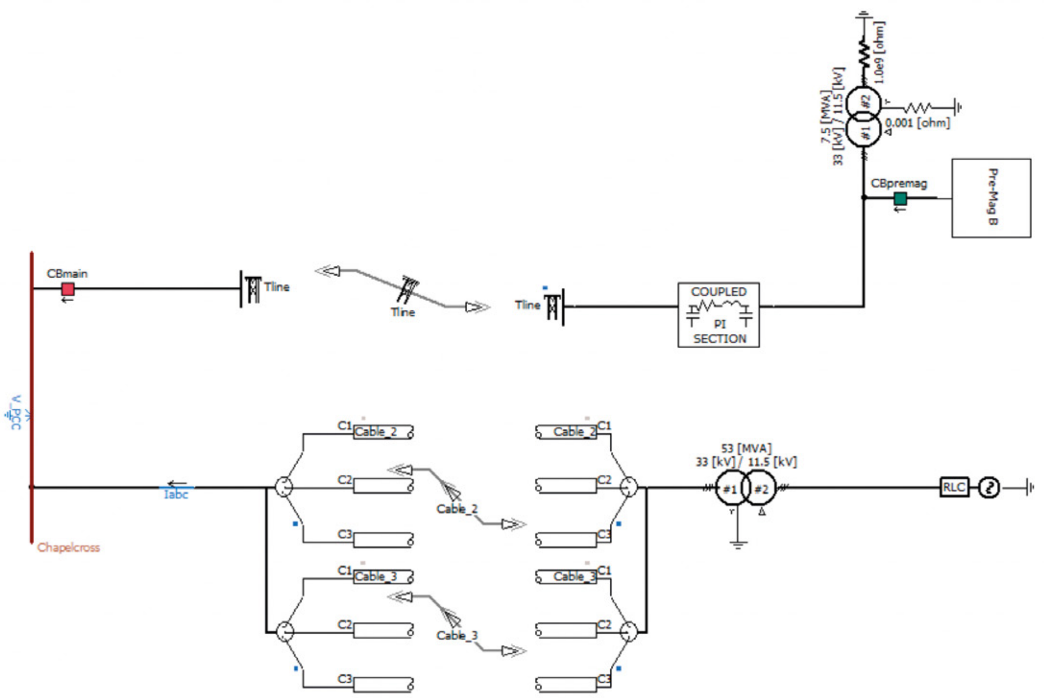
The model of the power island was developed using PSCAD electromagnetic transient (EMT) simulation tool. EMT simulations were performed and voltage dips subsequent to energisation of the 33/11kV primary transformer at Annan were examined at the Chapelcross GSP 33kV busbar and at Steven's Croft 11kV busbar, taking into account various network and operating conditions. The resultant voltage dips were then analysed and assessed against Engineering Recommendation (ER) P28, Distribution Code and other industrial recommendations.

Study data and PSCAD model

The Chapelcross GSP case study focuses on a 45 MW distributed generator located at Steven's Croft (11kV), which feeds a 53 MVA step-up transformer (33/11kV YNd11) connected to the Chapelcross GSP 33kV busbar via a 26km cable with 2x500mm2 cross section. The GSP 33kV busbar is connected via a 2.9 km cable/OHL to a 12 MVA primary transformer (33/11kV Dyn11) in Annan primary substation. Figure 8.13 shows snapshot of the model developed in PSCAD.

Please note that energisation of the 33/11kV transformer at Annan primary substation using the 33kV circuit breaker at Chapelcross GSP is actually energisation of the 33kV feeder including the 33kV cable/OHL from Chapelcross to Annan primary substation and the 33/11kV primary transformer.

Figure 8.13
PSCAD model of Chapelcross GSP case study



Transformer inrush modelling and validation

Four types of transformer with different MVA ratings and inrush characteristics were considered for the 33/11kV Annan primary transformer:

- 12MVA transformer with an inrush current of eight times nominal rating (base case)
- 7.5MVA transformer with an inrush current of eight times nominal rating
- 12MVA transformer with an inrush current of six times nominal rating
- 12MVA transformer with an inrush current of ten times nominal rating.

Each transformer was modelled, including saturation, to represent the full electromagnetic interaction with the site and external connected electrical system. It was assumed that the worst possible remnant flux (typically 0.8 p.u.) was present in the transformer prior to energisation.

Energisation study cases

The Chapelcross GSP case study was used as a base case for the analysis. Various network parameters were then changed in order to simulate a variety of network conditions, resulting in a total of ten cases:

- Case 1: Energisation of the 33/11kV transformer at Annan – Voltage at Chapelcross GSP set to 0.95 p.u.
- Case 2: Energisation of the 33/11kV transformer at Annan – Voltage at Chapelcross GSP set to 1.05 p.u.
- Case 3: Energisation of the 33/11kV transformer at Annan – Voltage at Chapelcross GSP set to 1.00 p.u. (base case)
- Case 4: Energisation of the 33/11kV transformer at Annan – The length of 33kV circuit between Steven's Croft and Chapelcross reduced from 26km to 15km
- Case 5: Energisation of the 33/11kV transformer at Annan – The length of 33kV circuit between Steven's Croft and Chapelcross reduced 26km to 5km
- Case 6: Energisation of the 33/11kV transformer at Annan – The size of the Steven's Croft generator reduced by half (to 29.86MVA)
- Case 7: Energisation of the 33/11kV transformer at Annan – High load level at Chapelcross (70 per cent of rated MW output from Steven's Croft unit)
- Case 8: Energisation of the 33/11kV transformer at Annan – Inrush current ten times nominal rating
- Case 9: Energisation of the 33/11kV transformer at Annan – Inrush current six times nominal rating
- Case 10: Energisation of the 33/11kV transformer at Annan – The capacity of the Annan primary transformer reduces from 12MVA to 7.5MVA.

Study results and assessment

For each case, the study identified the worst-case voltage dip and 50 per cent probability voltage dip for a random POW energisation, by energising the transformer on different time intervals over the entire cycle (20ms). The voltage was measured at Chapelcross GSP 33kV busbar and Stevens Croft 11kV busbar, 30ms after energisation. Voltage dips for the most onerous POW switching over the entire cycle of 20ms and for 50 per cent probability random POW switching are summarized in table 8.6 below.

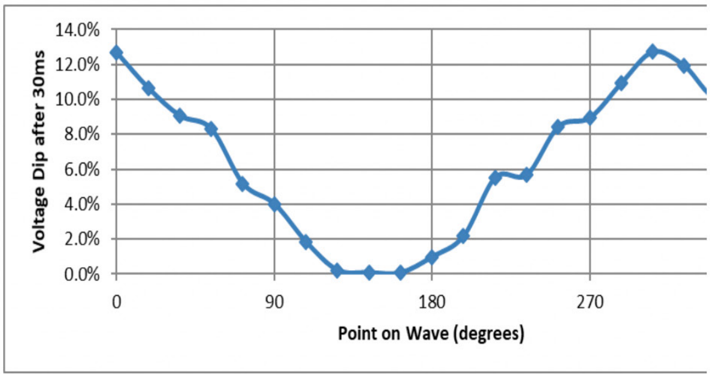
Figure 8.14 (a) and (c) shows an extract of the results for the case 3 (base case), together with a summary of the voltage dip results at Chapelcross GSP 33kV for all the cases against the ER P28 and Distribution Code limits for infrequent events (b).

Table 8.6
Voltage dip results in transformer inrush studies

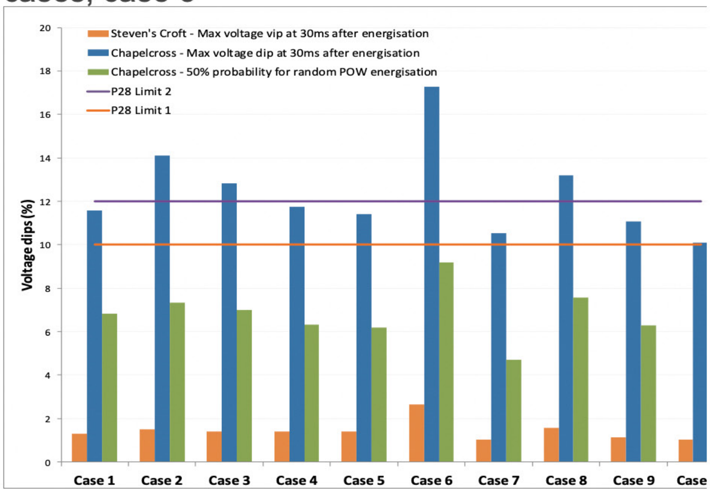
Cases	Description	Most onerous voltage dip (%) (Chapelcross)	Voltage dip with 50% probability for random POW (Chapelcross)	Most onerous voltage dip (%)
1	Chapelcross voltage set to 0.95 p.u.	11.56	6.83	1.30
2	Chapelcross voltage set to 1.05 p.u.	14.10	7.33	1.51
3	Chapelcross voltage set to 1.00 p.u. (base case)	12.83	7.00	1.41
4	Stevens Croft – Chapelcross cable length reduced from 26km to 15km	11.75	6.30	1.38
5	Stevens Croft – Chapelcross cable length reduced from 26km to 5km	11.42	6.17	1.38
6	The size of the Stevens Croft generator reduced by half (to 29.86 MVA)	17.26	9.17	2.64
7	High load at Chapelcross	10.52	4.71	1.03
8	Inrush current increased to ten times nominal rating	13.18	7.55	1.58
9	Inrush current reduced to six times nominal rating	11.06	6.29	1.13
10	Transformer size reduced to 7.5 MVA	10.09	5.72	1.01

Figure 8.14

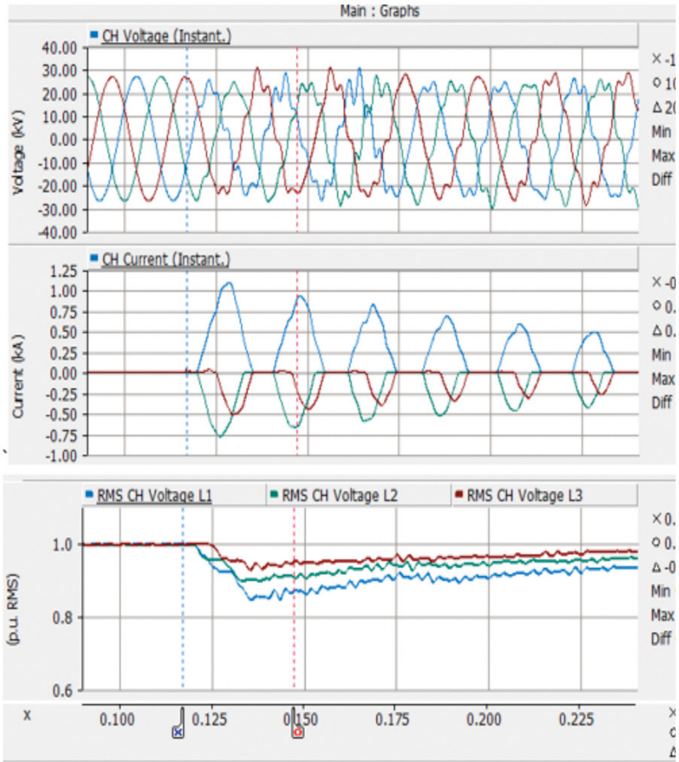
Primary (33/11kV) transformer inrush results at Chapelcross GSP



(a) Voltage dip results for various POW switching cases, case 3



(b) Maximum and 50% probability POW for all cases against limits



(c) Transformer energisation detailed results, maximum POW, case 3

Observations following the energisation of the 33/11kV transformer at Annan primary substation in other cases as compared with the base case (case 3) are summarized below:

- Reducing the Chapelcross GSP voltage from 1 p.u. to 0.95 p.u. lowers the voltage dip
- Increasing the Chapelcross GSP voltage from 1 p.u. to 1.05 p.u. enlarges the voltage dip
- Reducing the 26 km cable between Chapelcross and Stevens Croft to 15km and then to 5km decreases the voltage dip
- Reducing the size of the Stevens Croft generator increases the voltage dip
- High loads supplied at Chapelcross reduce the voltage dip by adding damping to the network
- Larger transformer inrush characteristics increase the voltage dip
- Reducing the size of the Annan 33/11kV transformer reduces the voltage dip.

The study results (figure 8.14 b and table 8.6) show that voltage dips with 50 per cent probability of occurrence at Chapelcross GSP 33kV busbar are less than the 10 per cent limit for all cases. The most onerous voltage dips corresponding to the worst-case POW exceed the ER P28 limits i.e. the 10 per cent limit in all cases and the 12 per cent limit in four cases. The worst voltage dip of 17.26 per cent is observed in the case in which a 29.86 MVA anchor generator is assumed at Steven's Croft instead of the existing one (59.68 MVA).

It should be noted that at least one GB DNO has been using the voltage dips with 50 per cent probability for random POW switching to confirm acceptance of transformer energisation events.

ER P28 and Distribution Code are normally applied to guide whether voltage dips resulted from energisation of transformers are acceptable. The Distribution Code states that for very infrequent events, it will generally be acceptable to design to an expected depression of around ±10 per cent of nominal voltage. The most recent version of the ER P28, indicates that studies involving transformer inrush current should consider energisation at a switching angle corresponding to zero volts in one phase resulting in the maximum voltage change of the phase (most onerous voltage dip), and that the maximum voltage change shall be taken to compare against the specified limits. A 12 per cent voltage dip for 100ms reduced to 10 per cent until two seconds, is permissible for very infrequent events (such as energisation of transformer during Black Start) according to the most recent version of the ER P28.

The document "Voltage Dip Immunity of Equipment and Installations", published by CIGRE/CIRED/UIE Joint Working Group C4.110, 2010, demonstrates that voltage dips resulting in voltage magnitude in the range 70 per cent–80 per cent may trigger motor tripping and even shut down industrial plants; voltage magnitude in the range 80 per cent–85 per cent within 500ms would be unlikely to trigger motor tripping. This document also specifies that all equipment for the end-users normally shall have the immunity for voltage dip up to 20 per cent while voltage magnitude is above 80 per cent for three seconds.

The transformer inrush study results indicate that voltage dip is less than 20 per cent at Chapelcross GSP 33kV busbar and the voltage magnitude in the range 80 per cent–90 per cent is less than 150ms subsequent to the energisation of the transformer in all cases. It is considered that the voltage dip and voltage magnitude would thus be unlikely to trigger tripping of motors and mal-function of equipment in the power island in accordance with the CIGRE document.

In addition, no over-voltage issues are observed during transformer energisation in all ten cases.

Conclusions

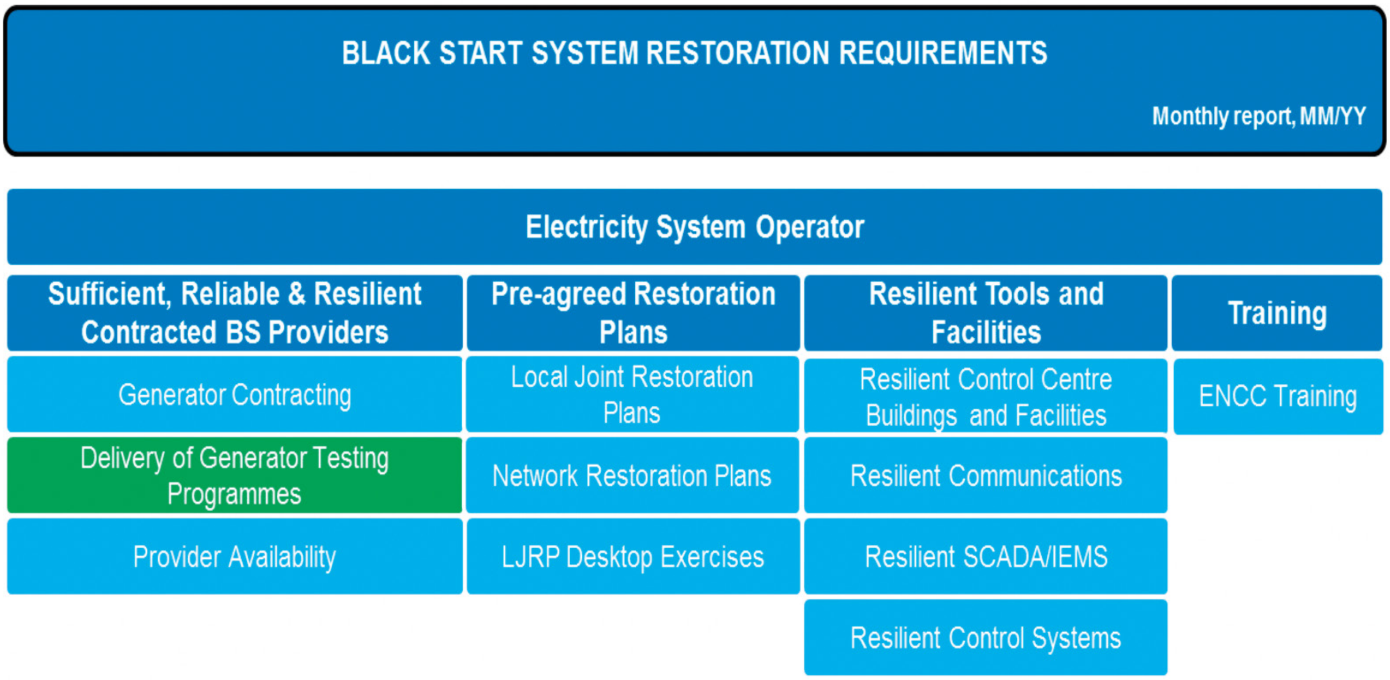
The transformer inrush study results at Chapelcross GSP 33kV busbar (worst-case POW) exceed the ER P28 10 per cent and 12 per cent limits in some cases, but are within the 20 per cent limit for equipment immunity. The results at the Steven's Croft DER are well within the 10 per cent limit in all cases.

It is concluded that transformer energisation may be an issue depending on the strength of the island (largely dependent on the fault contribution of the synchronous DERs) and the features of the transformer.
The following solutions may solve the transformer energisation challenges:

- point-on-wave switching devices to control the moment of circuit breaker closing
- reduce the voltage levels (but still within acceptable limits) prior to transformer energisation
- consider relaxation of voltage limits during Black Start
- for generator transformer energisation, consider ramping up the generator voltage with the transformer in service.

Appendix K – existing test procedures

Figure 8.15
Black Start system restoration requirements diagram



The overall objective of the assurance process is to periodically demonstrate that a Black Start Service Provider can deliver the contracted Service if called upon to do so. Testing is one element within the process. Further assurance is sought in three general areas:

i) the ability of the Service Provider operational staff to undertake a Black Start (the level of staff experience and the quality and frequency of training);

ii) the maintenance of accurate and appropriate procedures that would be used by operational staff in the event of a Black Start; and

iii) the continued technical capability of the plant to Black Start.

Black Start tests

Black Start Tests aim to assess the Service Provider's capability and provide assurance around the overall restoration approach of for the National Electricity Transmission System (NETS). Each Service Provider shall demonstrate its contracted Black Start capability at least every three years.

The Grid Code (OC5.7) prescribes two types of Black Start Test:

- Unit Test: In this test the power station as a whole remains connected to the grid so tests can be performed on individual units while the others remain in normal operation. The purpose is to demonstrate that the independent auxiliary supplies for a generating unit can be started and used to restart the generator. The generator being tested is shut down and its normal auxiliary supplies disconnected from the grid. The independent auxiliary supply is then started, which may be a gas turbine, diesel engine or other source as appropriate, and used to restart the main generator. The generator is then resynchronised with the system at its terminals in the usual way.
- Station Test: In this test the whole power station is disconnected from the grid and shut down. The facility must then restart and synchronise with the network without any external power supplies (or external fuel sources where applicable) within an agreed period (typically two hours from loss of supply). This test therefore provides a fuller demonstration of a Provider's Black Start technical capability.

The tests prescribed in Grid Code are supplemented by the following:

- A Dead Line Charge Test confirms the Provider's ability to charge a dead part of the network and its ability to control parameters, e.g. voltage, at the remote end. This test can be conducted in conjunction with a Station Test or with the Provider starting up using its usual auxiliary supplies.
- A Remote Synchronisation Test involves the Provider starting up, re-energising a dead test section of the network, as in a Dead Line Charge Test, and then synchronising to the rest of the system at the remote end. This test can be conducted in conjunction with a Station Test or with the Provider starting up using its usual auxiliary supplies.

To support re-energisation of the whole system and restoration of supplies to all customers each Provider must support the restarting of other generators. This is a more complex test as it involves additional parties and requires more onerous outages on the transmission network. However, such tests are important to demonstrate the capability and readiness of the Provider, the transmission network, and the "secondary" generator that is restarted and synchronised.

Black Start tests in GB do not include the disconnection of demand customers and subsequent restoration of their supplies, although this is done in other countries. Of course, supplies are disconnected and restored all the time for a multitude of reasons so the DNOs and TOs are well practiced in restoration on a small scale. However, apart from as a result of very serious storms, such outages are usual very limited in scope and duration. A more widespread shut down of the system, possibly lasting several days, will present additional challenges, as discussed elsewhere in this report. Modelling and offline assessment are important to ensure capability and readiness on this aspect of the restoration process.

A new Black Start Service Provider will be required to pass a two part **Commissioning Assessment** before the service can commence. The first part relates to resilience and capability of the auxiliary supplies and the second part may include a range of tests as deemed necessary by NGESO. Following a period where a Black Start service has been unavailable NGESO may request a **Reproving Assessment**. The extent of all testing is agreed with the Provider.

When scheduling Black Start Tests, factors to consider include:

- **Service Provider Outages.** For example, at a multi-unit Power Station choosing a date when some units are on outage can reduce cost. However, some Stations object to this as contractors cannot work on the outage during the test day. Information on declared generation outages can be referred to for these large generators.
- **Outages in the vicinity of the test.** In particular, care must be taken regarding supergrid transformer (SGT) outages. Guidance should be sought from the relevant planning teams as to the viability of tests in combination with outages. For example, depending on the auxiliary power back up arrangements at the substation, power for SGT cooling may be lost, which may further constrain the window of opportunity for testing.
- **Market impact and potential operability constraints.** NGESO will not want to rely on a generator coming back to provide part of any significant demand pickup, especially the morning pickup. However, as a rule it is preferable to aim to have the generator desynchronising as national demand falls and then to resynchronise as demand increases. Historical demand data will aid in planning the timing of the test. Most testing will need to be planned during the warmer months between clock change to maintain sufficient margin and reduce costs. The provision of ancillary services may also be impacted by the Black Start Tests.
- **Timing.** To minimise costs and maintain sufficient margin Black Start Tests may need to take place over the weekend. Furthermore, it is preferable to avoid organising tests on Mondays or Fridays due to staff restrictions.

Assurance visits

Assurance visits are planned to develop a Black Start Service Provider's internal processes, training, plant status and procedures pertaining to Black Start to a level where they are comparable with best practice. Whilst a Black Start Test is still recognised as the ultimate arbiter of a Provider's capability, this less disruptive ongoing assessment of service delivery methodology is undertaken in addition to testing to increase the level of service assurance.

It is important that it is stressed to the Service Provider that this process is in place so that NGESO can help them provide a better service. The process should be seen as a joint venture. In this manner a more complete and honest exchange of information should be achieved.

Before the actual visit to the Service Provider to complete the assurance visit, a blank copy of an assurance visit report is sent to the Service Provider so that they are aware of what access and information may be needed. It is also advantageous to obtain copies of any Provider's documentation that is covered in the report's scope before the visit.

The visit to complete the report should be conducted in the manner of a two-way discussion. Areas of strength should be complimented and areas for improvement should be mutually agreed. Any actions to take forward should also be jointly agreed and will form the starting point of a subsequent assurance visit or Black Start Test pre-meeting. A formal copy of the assurance visit report should be sent to the Service Provider on completion of the visit. A copy should be added to the Provider's testing history file. The frequency of assurance visits is every three years.

Desktop exercises

Desktop exercises take place with the parties to a specific Local Joint Restoration Plan (LJRP), i.e. NGESO, the relevant Black Start Service Provider, and the local TO and DNO. The aim of these exercises is to bring together all parties to foster a common understanding of the LJRP, raise and maintain awareness of Black Start issues, test the LJRP effectiveness, and identify any improvements. It expands on the Service Provider's specific assurance activities conducted by NGESO to examine the conduct of the overall restoration process during the LJRP phase.

NGESO has the specific responsibility of proposing and seeking agreement for a date for such an exercise to take place, however the Grid Code states that it is the responsibility of all parties to jointly share the task of planning, preparing, participating in and facilitating these exercises. When inviting parties to such an exercise it is important to stress this joint responsibility and seek input other than from NGESO.

Holding an exercise at the Service Provider plant allows for a site tour although this is not essential. Exercises should be located as best to suit the agenda, for example, should a simulator exercise be included as part of the day. There is no fixed format, each exercise should be tailored to the issues raised by the participants. Exercises are often run to a NGESO proposed agenda but encouraging the other parties to reflect on and raise their own issues in advance of the exercise can improve the benefit derived from the day. Key points and agreed actions captured from the day should be circulated to all concerned and feedback should be encouraged from participants on what they would wish from a subsequent exercise. The outcome of each Desktop Exercise is the re-issue of the LJRP, signed by all parties.

Appendix L – issues register

Issues register – DER technical

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DER Technical	T1	Converter connected generation is sensitive to low system fault level and resulting voltage instability.	The fault level might not be sufficient to allow converter connected gen to stably connect. Control settings may need changed for Black Start scenario. The gen may trip for system disturbances.	Power system analysis/manufacturer modelling required to determine minimum fault level for operation and stability. Provide suitable mechanism to change converter control settings for Black Start.	
DER Technical	T2	Dynamic models not available for DER (unless large as defined in the Grid Code). The dynamic models for DER (if available) or the generic dynamic models may be suitable for normal operation only and not for Black Start related simulations	Dynamic response required to know key parameters such as the block load capability (for synchronous generators).	Request the developer provide a dynamic model suitable for Black Start simulations. Carry out an initial 'live trial' with relevant gen to ascertain the dynamic f control load response of sync gen, or MW output response time of converter connected.	
DER Technical	T6	Most anchor generator types need a minimum demand to start with (to avoid overheatng the boiler or turbine blade cavitation). This ranges from ~20% to 50% of rating.	It is unlikely this demand can be provided from the network due to: i) the uncertainty of demand being connected, ii) the demand exceeding the gen load pick up capability.	Start the gen against a load bank, or utilise a battery if available.	
DER Technical	T3	Most existing DER normally operates in base load (MW control), and may not have frequency control installed (unless a Grid Code large power station).	Frequency control is required on at least one anchor gen when operating in an island.	Install/enable frequency control as required on anchor gens to operate in a Black Start scenario. Assess using local freqency control for converter connected gen compared to a microgrid controller to control the MW output.	
DER Technical	T4	DER in England & Wales typically operates in power factor control	Voltage control is required on at least one anchor gen in an island. Gen control modes may need to be changed for Black Start. The DNO connection may not be suitable for V control.	Install voltage control as required on anchor gens. Provide suitable mechanism for changing excitation control options. Study the DNO connection to ascertain if suitable for V control. Consider limiting MW o/p of gen if thermal/voltage issues.	
DER Technical	T5	DERs have different control methods. Some manned 24/7, others are fully remote controlled and others a combination.	Resilient control of the DER from Black Start will have to be developed taking into account all current control methods.	This issue will be investigated by the Organisational Systems and Telecommunications workstream.	
DER Technical	T7	Wind farm, battery and solar sites are typically not permanently manned and are controlled remotely.	Direct control of the DER may be required as part of an islanding control scheme (i.e not via a remote control room).	This issue will be investigated by the Organisational Systems and Telecommunications workstream.	
DER Technical	T8	Some wind farms require to start at ~10% of its rated output.	The network to which it connects must be capable of absorbing the minimum wind farm export power.	The MW control scheme for the island, or anchor DER, should be able to accommodate the minimum MW output of a wind farm when connected.	

Issues register – DER resilience

DER Resilience	DR1	Varying capacities, and sustainability, of auxiliary backup supplies. Some battery backup only. Others limited standby gen (e.g for essential services and/or to protect the	Auxiliary power required to maintain availability of gen (e.g protection, comms, keep boiler warm) and to be able to self start (typically 10-15% of MW rating required).	Install the required capacity of auxiliary power (e.g diesel gen) for self-starting, with suitable changeover scheme with normal site aux supplies.	
DER Resilience	DR2	Generators utilising a combustion process (e.g EfW) must control their operation (e.g ramp rates) to keep within emissions limits.	The operation required for black start (or the project live trials) may result in the generator emissions limits being exceeded.	Procurement and Compliance workstream to seek resolution of this issue with the relevant authorities.	
DER Resilience	DR3	Fuel stores are typically in the order of several days. For some ash disposal may be an issue after several days.	A suitable resilience timeline for DER types will need to be defined.	DERs may be able to change their operating regimes to meet increased operating times for Black Start.	
DER Resilience	DR7	Wind turbines receive their auxiliary supplies (e.g for heating) from the incoming 33kV supply. After ~6 hours outage the gear box oil may have cooled too much to allow restarting (depends on ambient temperature).	If the DNO connection is not restored to a wind farm within ~6 hours it may take days to restart due to the turbines having to be individually pre-heated.	Plan the DNO restoration strategies such that supplies are restored to wind farms as a priority. Contract that a WF has to install back up generation capable of supplying each turbines auxiliary load.	
DER Resilience	DR9	Wind turbine gear box oil requires pre-heating after ~6hours shutdown	It could be days before a WF is available if turbines require individual pre-heating.	i) Prioritise restoration to WFs (6 hours possible for all)? ii) WF installs aux power to keep 33kV network energised.	
DER Resilience	DR4	A licence condition of certain generators is that they do not discuss Black Start in public documents (e.g planning applications).	A DER may have to make modifications for Black Start which would normally require public disclosure of the reason.	Clarification required of this licence condition applicability to DER and how it may be removed or mitigated.	
DER Resilience	DR5	A DER receiving Renewable Obligation Certificate (ROC) payments requires Ofgem approval to any changes tp their electrical Single lIne Diagram (SLD).	Changes to a DER SLD may be required to make them resilient and self-starting	Issue to be resolved with Ofgem.	
DER Resilience	DR6	Varying capacities, and sustainability, of auxiliary backup supplies. Some battery backup only (e.g for telecoms and protection). Others limited standby gen to maintain essential services for several days.	It may not be possible to communicate with the site, or reastart after a Black Start if the essential services back up supplies are not adequate.	Install the required capacity of auxiliary power (e.g diesel gen) for self-starting, with suitable changeover scheme with normal site aux supplies.	
DER Resilience	DR8	A hard trip (not ramping the output down) stresses the wind turbines and they are then more prone to faulting and not reconnecting.	The relative voltage and frequency instability of a power island may result in a wind farm disconnecting more often.	The island control scheme should be designed to avoid hard trips of a wind farm where possible.	

Issues register – earthing and distribution island operation

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
Earthing	E1	The 33kV network will be unearthed if the grid transformer L.V circuit breakers are open. In addition, the location of the earthing transformers does not comply with the ESQCR when the network is energised from a DER remote to the grid substation.	An alternative means of earthing the 33kV network will be required if a 33kV power island is to be established.	An earthing transformer could be installed at the anchor generator 33kV substation. The DNO policy could be changed such that new anchor generators provide a switchable earthed 33kV transformer winding.	
Protection	P1	There may be insufficient fault level for existing protections to operate adequately for a distribution power island.	The protection will need to be able to detect and clear faults before the network can be energised from DER.	A protection assessement should be carried out on all potential power islands to identify protection issues. A policy should be developed for the minimum protections required for a Black Start scenario. Most protection issues can be overcome by having separate Black Start settings.	
Earthing	E2	The Rise of Earth Potential (RoEP) may increase at the grid substation with an earthing transformer fault infeed from a remote generator site.	Safety is required to be maintained at the grid substation.	An earthing study may be required at the grid substation to confirm if the existing earth mat is adequate.	
Earthing	E3	The33kV generator earthing transformer should not be operated in parallel with more than one grid earthing transformer.	It is unlikely that expansion of a 33kV power island would involve more than one grid transformer connected to that network.	Restoration plans will have to ensure only one grid transformer is switched in service with an anchor generator with an earthing transformer.	
DIO	DIO 1	A distribution power island will have a low fault level relative to normal operation.	Existing protection may not be able to detect faults/operate quickly enough. Voltage disturbances will be greater causing unwanted protection operations. Converter connected generation may not be able to connect or remain stable	Carry out a protection study and provide alternative settings/protections for a Black Start scenario. Converter manufacturers to determine if the coverter can be 're-tuned' for the available fault level, and if settings can be changed automatically for a Black Start. Prioritise the energisation of available syncronous DER	
DIO	DIO 2	System oscillations.	Oscillations between power, voltage and frequency can occur on a closely coupled distribution power island.	Carry out the required transient/dynamic studies to identify any issues. Install suitable monitoring equipment during trials. Design mitigation measures e.g fast f response if available from DER.	
DIO	DIO 3	Lack of human resources (DNO control engineers and DER personnel) to establish and maintain distribution power islands and associated restoration times with only manual intervention.	Design a level of automation into the Black Start from DER process that makes it viable with existing human resources but also results in a safe and manageable system.	Identify the required functionality and architecture for microgrid controllers to provide the required level of automation.	

Issues register – distribution island operation and resilience

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
DIO	DIO 4	Block load capability of DER in a power island.	The block load capability of DER (due to low system inertia) may not be sufficient to pick up the demand of a primary substation. Additional 11kV switching may be required to reduce the demand block size which may not be viable operationally and completed within exceptable timescales.	Options for reducing the net block loading a DER 'sees' by using load banks or batteries (controlled by a microgrid) should be investigated.	
DIO	DIO 5	Low system inertia.	A generation/load imbalance will cause larger frequency changes due to low inertia.This will result in a more severe test of the generator's governors than with intact system conditions.	Where practical a control scheme should be employed to minimise the generation/load imbalance of the power island which the generator 'sees'. If available, additional anchor DER could be brought on line initially to increase inertia.	
DIO	DIO 6	High variability of load and generation (particularly solar).	It may be hard to maintain a stable frequency in a power island where the demand and intermittent generation resources are much more variable on a power island.	The capacity of intermittent generation connected (particularly solar) will have to be limited to take into account the unpredicatability of the resource. Adequate capacity margin will be required on the synchronous generation.	
DIO	DIO 7	Power island 33kV voltage control	When operating a 33kV power island there will be no direct way of monitoring or controlling the 33kV voltage.	A microgrid controller could be utilised to monitor the 33kV voltage and take corrective actions e.g. switch in/out reactive compensation. Alternatively DER could be used to monitor and control the 33kV voltage.	
RES	R1	The protection and SCADA at substations is dependent upon batteries which have variable resiliences from ~18 hours to 72 hours without a	A substation may not be safe to energise at the required time after a Black Start if the protection and SCADA was not available.	Ensure that the batteries have adequate resilience at the key substations, or standby generation is installed to maintain the battery charging.	
RES	R2	It may only be possible to close a circuit breaker at a substation once after which there will be no LV supply to recharge the closing springs.	A circuit breaker is closed as part of a power island restoration plan. If the power island collapses, or the circuit breaker has to be opened to shed load, it may not be able to be reclosed.	Install standby generation to provide a LV supply to recharge the springs. Plan the restoration strategy so that the substation providing the LV supply to the main substation is energised first.	
RES	R3	If there is no LV supply at a transformer substation the transformer tap change motor will not operate.	When a transformer is energised, its LV voltage may be out with satisfactory limits and if high voltage may cause damage to equipment.	Energise the transformer with its load connected to avoid high open circuit 11kV voltages. Install stanby generation at strategic substations for the tap chage motors. Ensure when a transformer is energised it is energised with the load connected that provides the LV supply to the transformer substation.	

Issues register – network system studies

Issues Register					
Category	**No.**	**Description**	**Black Start DER Challenges**	**Potential Solutions**	
Network System Studies	S1	Opening circuit breakers to create restoration paths and reduce block loading in SPM	Most of the SPM network is highly meshed, with interconnection at all voltage levels. This can pose challenges when opening circuit breakers to create restoration paths. Moreover, primary substations (33/11kV) share the same interconnected network at lower voltages (11kV and LV) in normal operation.	Splitting the 11kV and LV meshed network by establishing multiple open points in the primary group prior to the Black Start would ensure that the size of the block loads is reduced to the capacity of primary transformers, reducing the impact on the DER. Confirmation of its practicality requires further detailed analysis for each specific primary group. If the primary groups cannot be practically split, then solutions to take on larger block loads consistent with the full primary group load need to be identified, e.g. expanding the island system to energise multiple DERs and increase online generation capacity prior to taking on large block loads, load banks installed at the DER anchor generator site to compensate for the connection of large block loads.	
Network System Studies	S3	High voltages on the 11kV side of the primary 33/11kV transformer if energised open circuit	Prior to a black out, the primary transformer may have been heavily loaded and the tap changer will have tapped to a position to keep the 11kV voltage within acceptable limits. If the transformer is then energised without the load, studies have shown that the open circuit 11kV voltage may be up to 10% high. There will also be no local LV supplies available to power the tap change motor and reduce the voltage.	Energise the primary 33/11kV transformer together with its load connected (the 11kV circuit breaker closed to connect the load). However, the consumers may experience large voltage dips due to transformer inrush. Reduce the voltage levels at 33kV (but still within acceptable limits) prior to transformer energisation	
Network System Studies	S2	Insufficient reactive power in the power island which can generate voltage exceedances	DERs may not have sufficient reactive power capability to sustain the growth of the island and to mainain voltages within the acceptable limits	Prioritise the energisation of multiple DERs in the power island If possible, renewable DERs (WF, SF) to provide reactive power support as much as they can Taking on part of load to reduce voltage magnitude Utilising existing reactive power compensation devices and transformer taps to control voltage Reactive load banks installed at the DER anchor generators Specifying higher MVAr requirements for anchor generators. ER-G99 requires a power factor range of 0.92 (lead). Generators in Scotland are presently required to have this capability but this is not the case elsewhere in the UK The restoration plans need to be carefully selected to avoid exceedances of voltage limits	
Network System Studies	S4	High voltage step changes	High voltage step changes may occur in weak systems such as power islands	Dynamic analysis in the Design Stage will further study this issue	
Network System Studies	S5	Voltage dips due to transformer energisation	Due to low fault levels in the power island, voltage dips may occur during transormer energisation	Point-on-wave switching devices to control the moment of circuit breaker closing Reduce the voltage levels (but still within acceptable limits) prior to transformer energisation Consider relaxation of voltage limits For generator transformers, consider ramping up the generator voltage with the transformer in service	

Appendix M – figures and tables

Figures

Tables

Appendix N – table of abbreviations

Abbreviation	Definition
AVC	Automatic Voltage Control
AVR	Automatic Voltage Regulator
BES	Battery Energy Systems
BOA	Bid Offer Acceptance
BS	Black Start
BSP	Bulk Supply Point
CCGT	Combined Cycle Gas Turbines
CHP	Combined Heat and Power
DER	Distributed Energy Resource
DNO	Distribution Network Operator
EfW	Energy from Waste
EHV	Extra High Voltage
EMT	Electro-Magnetic-Transient
ER	Engineering Recommendations
ESQCR	Electricity Safety, Quality Continuity Regulations
ETYS	Electricity Ten Year Statement
f	Frequency
GSP	Grid Supply Point
GT	Grid Transformer
HV	High Voltage
HVDC	High Voltage Direct Current
LPS	Large Power Station
LTDS	Long Term Development Statement
MITS	Main Interconnected Transmission Network
NETS	National Electricity Transmission System
NGESO	National Grid Electricity System Operator

Abbreviation	Definition
NGET	National Grid Electricity Transmission
OLTC	On-Load Tap Changer
PLL	Phase Locked Loop
POW	Point On Wave
PET	Power Engineering and Trials
PV	Photovoltaic
ROCOF	Rate of Change of Frequency
RTS	Return to Service
SCADA	Supervisory Control and Data Acquisition
SHET	Scottish Hydro Electric Transmission
SLD	Single Line Diagram
SPD	Scottish Power Distribution
SPEN	Scottish Power Energy Networks
SPM	Scottish power Manweb
SPT	Scottish Power Transmission
STOR	Short Term Operating Reserve
TO	Transmission Owner
WF	Wind Farm
LPS	Large Power Station

Notes

National Grid System Operator
Faraday House
Warwick Technology Park
Gallows Hill
Warwick
CV34 6DA
United Kingdom

Registered in England and Wales
No. 4031152

www.nationalgrideso.com

nationalgridESO