The impact of Electric Vehicle charging on grid short term frequency and voltage stability, and cascade fault prevention and recovery.

Work Package 2 Report Prepared For National Grid ESO

September 2022

Resilient Electric Vehicle Charging "REV"

SYGENSYS

INTRODUCTION

Smart charging impacts grid stability

There is a rapid uptake of electric vehicles and smart charging, forecast to become a greater than 10 GW controllable demand-side resource in the 2030s. Just as inverter-connected generation has brought new challenges for grid operation, the presence of these new types of smart load will introduce system risks that have not been seen before. Vehicle to Grid will provide a major storage resource, also forecast to provide over 10 GW from behind-the-meter infeed in the 2030s.

Both EV Charging and Vehicle to Grid include complex protection systems which can trip load or generation in response to grid voltage, phase or frequency excursions. Quantifying these risks via simulation is difficult as existing modelling does not provide a good representation of the response of EVs during system contingencies.

Appropriate specification and implementation of control systems for these resources can help balance supply and demand and enhance system security. **A conservative estimate of the savings from smart charging is around £400m[1] per year by 2030, growing significantly through the 2030s.**

Smart charging represents both a threat to the grid and an opportunity to reduce costs and enhance system reliability

"DERs can create new power system opportunities, but at the same time, can pose new challenges when a grid has not been properly prepared. Many jurisdictions are just beginning to understand how DERs fit into the wider energy landscape – what they are and what impacts they have on the grid, and how they can be used to improve system reliability and reduce overall energy costs. Meanwhile, other regions have built up experience with DERs, demonstrating that they can provide valuable services to the grid when incentivised with appropriate technologies, policies and regulations." [2]

[1] Based on mid 2021electricity prices
[2] Unlocking the Potential of Distributed Energy Resources - IEA

Smart charging and V2G is an emerging threat to grid stability.

INTRODUCTION

The scale and nature of the challenge

The scale and nature of the move to decarbonized transport and heat is unprecedented.

Scale:

The total capacity of this load before diversity could exceed 100GW by 2030, ultimately reaching over 300GW.

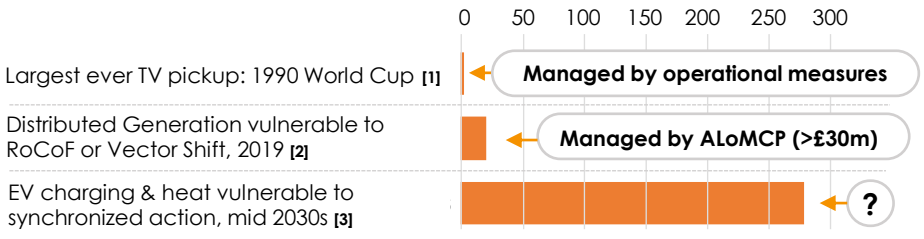
Nature:

This new load will be:

- Software-driven, with sophisticated protection & control functions;
- Energy intense;
- Open to human intervention (from consumers or hackers).

Taken together, the scale and nature of these new loads introduces **new operational risks** for ESO to manage, particularly synchronised action, whilst at the same time there is a risk that **the effectiveness of traditional system management capabilities will be eroded**. These two risks are explored in the next two slides, and then summarized in an infographic which presents the future system in terms of the power domain and the "digital domain" – the world of software.

Approximate scale of potential synchronised action (GW)



In addition to these new load types, new grid management techniques are likely to be introduced including Active Network Management systems (ANMs) to manage these loads and demand-side services to exploit their potential. Like the loads themselves, these **critical network security tools will also be dependent on highly distributed and complex software systems**.

[1] EURO 2020 and the TV 'pick-up' effect
[2] The growth of distributed generation in Great Britain and associated challenges
[3] Based on FES2022

Software control systems and communication links used to deliver flexibility from mass consumer devices will become a major new operational risk.

INTRODUCTION

New operational risks

Synchronised action has been a long-standing feature of power system operation, for example TV pickups and Triad avoidance. However, the move to electrified transport and heat introduces new potential mechanisms for synchronised action which could dwarf these historic phenomena, as set out opposite. **Synchronised action could take the form of steps, ramps or oscillatory load behaviour**.

A significant new factor in these risks is the **emerging importance of the "digital domain"** – the world of software systems. Traditionally, power system security has been ensured by managing risks in the power system domain, such as circuit faults and generator trips. With the capacity of smart loads reaching tens and then hundreds of GW, however, **"digital contingencies" such as the failure of an ISP or aggregator's IT system** could have an impact greater than traditional power system events. Coordinated **consumer action** - possibly facilitated by social media - could produce substantial load swings, whilst the **protection and control characteristics** of popular smart devices could give rise to a significant coincident tripping risk if the design is only focused on the consumer experience.

The present **half-hour market design** may produce significant load steps when price changes occur, and is unlikely to be able to deliver smooth alignment of LCT energy requirements with the availability of renewable energy.

Potential sources of synchronised action:

Consumer action

"Panic" (pre-emptive) charging & heating
E.g. in response to an ESO margin notice, or a severe weather forecast

"Greedy" charging & heating
Over-riding smart control features, e.g. following a loss of supply

Power system events

Fault Ride-Through failure
(PLL, Vector Shift, RoCoF)

Cascade voltage tripping
(in response to a transmission voltage event or DSR action)

Changes in system stability behaviour post event due to constant-power or constant-current operation

Market design & operation

Time of Use tariff price steps
Real or accidental. Half-hour pricing is too coarse to deliver the smooth demand profile required

Hard-coded "economy" periods
Included in current regulations

Digital domain events

Outage or maloperation of components of the IT ecosystem
Caused by power outage, software mishap, unforeseen interactions, malicious action etc.

Customer-centric device design
Recovery phase actions designed for consumer benefit regardless of system impact.

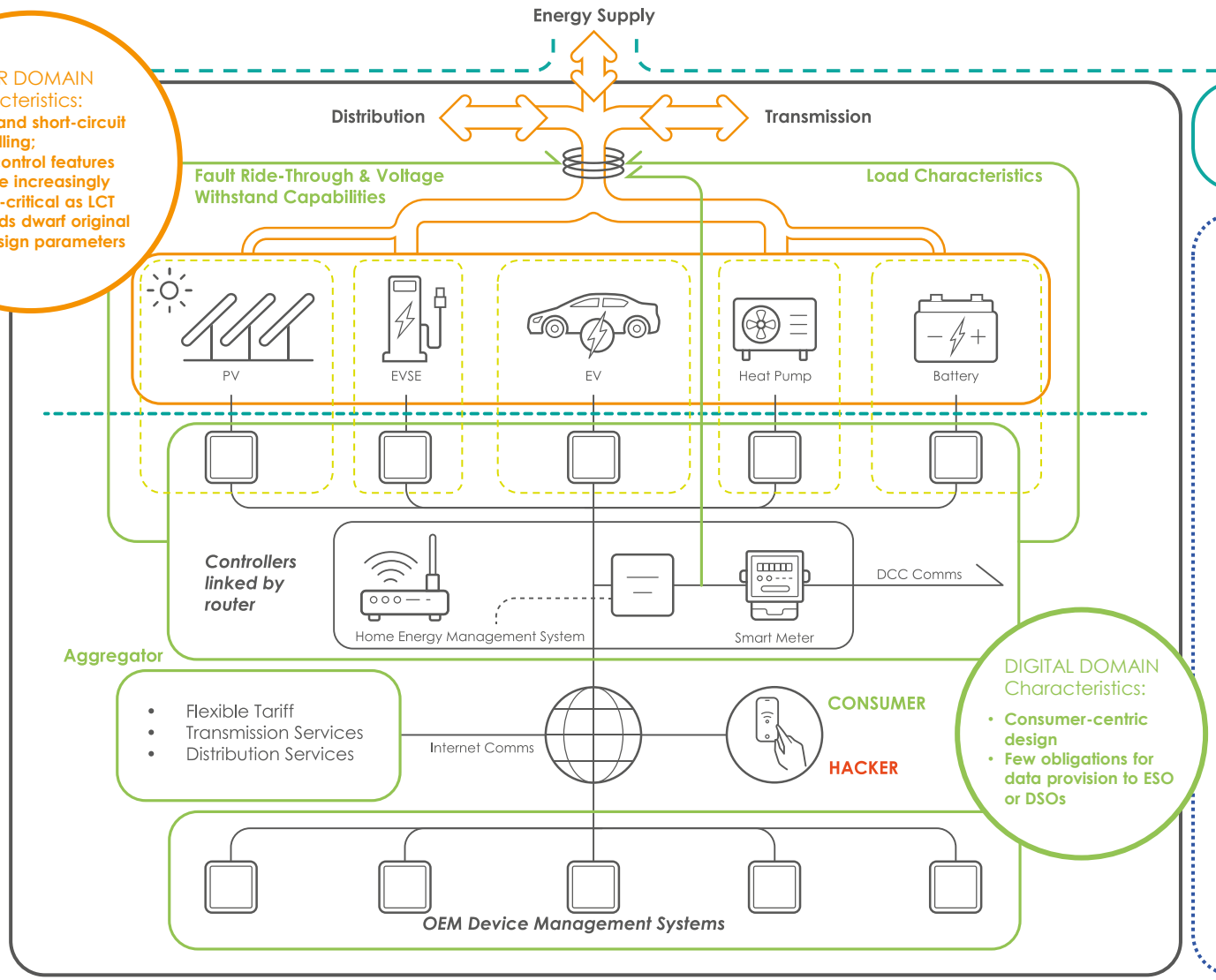
Unmanaged synchronised action is a major threat to operability.

The capacity of EVs and domestic heat pumps on the system could exceed 100GW by 2030, eventually reaching over 300GW.

[FES 2022 data with average 7kW rating]

POWER DOMAIN Characteristics:

- **Inertia and short-circuit level falling;**
- **Smart control features become increasingly mission-critical as LCT demands dwarf original grid design parameters**



DIGITAL DOMAIN Characteristics:

- **Consumer-centric design**
- **Few obligations for data provision to ESO or DSOs**

Capability requirements

ESO & DSO capabilities will need to be enhanced in the following areas:

Data:

Additional data for planning, operations and post-event analysis.

Analysis techniques:

Combined T&D models (in some form) to study voltage tripping risk, EMT modelling to study fault ride-through.

Schedule & Dispatch:

Deliver energy over variable time windows at lowest carbon footprint (rather than power at lowest cost).
Manage risks of "digital contingencies".
Update demand control techniques.

Restoration:

New simulation and control methods to manage increased energy demand and complex digital interactions.

Smart charging benefits likely to reach £400m pa by 2030

Operational risks

Steps, ramps or oscillations in power transfer could arise from the following sources:

Power system events:

E.g. fault ride-through failure, voltage or RoCoF protection tripping (especially during restoration).

Consumer behaviour:

"Panic charging" ahead of real or perceived risks to supply (and during restoration). Fuelled by social media.

Market design:

Real or accidental Time-of-Use price steps.
Insufficient granularity to manage scale of LCT demand.

Digital domain complexity:

Unforeseen interactions between systems.
Failure or maloperation of eco-system components.
Extensive cyber-attack surface.

Do not underestimate the scale and impact of the digital domain as we move to energy smart appliances.

The capacity of EVs and domestic heat pumps on the system could exceed 100GW by 2030, eventually reaching over 300GW.
[FES 2022 data with average 7kW rating]

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Manage risks of "digital contingencies".
Update demand control techniques.

Restoration:
New simulation and control methods to manage increased energy demand and complex digital interactions.

Develop regulatory framework for power domain

Develop regulations for LCT to support secure operation during normal and restoration conditions, including:

- fault ride-through capabilities;
- steady-state voltage withstand;
- smooth mandatory frequency response;
- avoiding hard-coded time periods;
- emergency control action when needed.

Develop "Decarbonisation Capabilities Program" covering all four areas:

- Data
- Analysis Techniques
- Schedule & Dispatch
- Restoration

Will require engagement and collaboration from traditional industry participants plus LCT consumer device vendors and IT eco-system providers.

Reform market design

Ensure that market design enables demand to be smoothly controlled to align with renewables availability, whilst meeting LCT energy requirements over various time windows with minimum carbon footprint.

Update security standards

Consider how SQSS might be extended to cover emerging risks such as:

- "digital contingencies" (e.g. failure of ISP or aggregator IT system);
- "distributed" loss of demand or generation; multiple tripping of consumer devices due to power system events, without actual disconnection.

Develop regulatory framework for digital domain

Develop requirements for participant IT system resilience and cyber security, taking account of third-party dependencies.

Smart charging benefits likely to reach £400m pa by 2030

Operational risks

Steps, ramps or oscillations in power transfer could arise from the following sources:

Power system events:
E.g. fault ride-through failure, voltage or RoCoF protection tripping (especially during restoration).

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Digital domain complexity:
Unforeseen interactions between systems.
Failure or maloperation of eco-system components.
Extensive cyber-attack surface.

Multi-faceted risks will require a wide range of prevention and mitigation actions.

INTRODUCTION

New capability risks & requirements

NGESO relies on well-established capabilities for planning and operating the system, using Grid Code data supplied by generators and distribution companies to build models of the network for power system analysis. However, **these analysis techniques may not be sufficient** to assess the risk of coincident or cascade tripping of smart loads due to the operation of voltage protection or phenomena such as “PLL unlock”, which may require EMT simulation.

Furthermore, there are little or **no obligations on third parties to provide planning data** on numbers, locations and characteristics of devices to DNOs or NGESO to support such studies, and **no real-time data** to monitor operation or carry out post-event analysis. Any undesirable system phenomena arising from malfunctioning of a particular manufacturer’s charge-point, for example, would be impossible to diagnose.

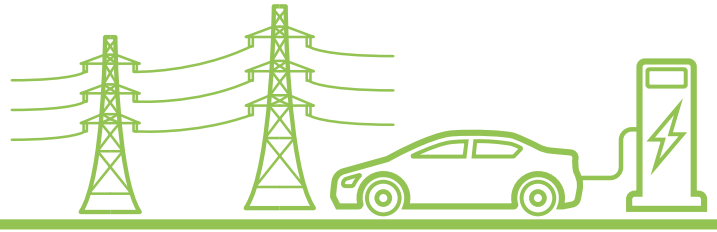
For OC6 demand management, **the effectiveness of voltage reduction will be eroded** due to the constant-power / constant-current nature of these smart loads, and **the effects of LFDD will be reduced** where V2G generation is present.

To move beyond the half-hour market with its propensity to create step changes in load, NGESO’s **forecasting, scheduling and dispatch activities will need to adapt to a world where energy is as important as power**.

The primary requirements of both heat and transport are to receive sufficient energy within a particular time window; the profile of that energy (the power level) is secondary. To match energy demand to available renewable energy, and top up where necessary with other types of generation, NGESO may need to know the energy requirements of aggregators over various windows, potentially up to 24hours, and then dispatch to meet that energy requirement.

Finally, and critically, **NGESO’s capability to restore the system** after a local or national shutdown **could be significantly hampered** by these new load types. The Cold Load Pick-Up will be substantially increased in magnitude and duration compared to traditional assumptions. Smart loads will be prone to tripping in the disturbed conditions that can be seen during restoration, which could destabilise the process, and smart network management systems such as ANMs may be unavailable if key parts of the IT infrastructure have not had power restored.

Effective management of new smart loads requires a broad range of new capabilities.



CONTENTS

Click section titles to navigate

Abbreviations

AEMO	Australian Energy Market Operator
ALoMCP	Accelerated Loss of Mains Change Program
ANMs	Active Network Management systems
BESS	Battery Energy Storage System
BMRS	Balancing Mechanism Reporting Service
BOA	Bid Offer Acceptance
BS	British Standard
BSP	Bulk Supply Points.
CLPU	Cold Load Pick-Up
DCC	Data Communications Company
DER	Distributed Energy Resources
DG	Distributed Generation
DNO	Distribution Network Operator
DPV	Distribute Photo Voltaic
DRZ-C	Distribution Restoration Zone Controller
DSO	Distribution System Operator
DSR	Demand Side Response
EFCC	Enhanced Frequency Control Capability
EMT	Electro Magnetic Transient
ENA	Energy Networks Association
EPRI	Electric Power Research Institute
ER	Engineering Recommendation
ESC	Energy System Catapult
ESO	Electricity System Operator
ESQCR	Electricity Safety, Quality and Continuity Regulations
EV	Electric Vehicle
EVC	Electric Vehicle Charging
EVSE	Electric Vehicle Service Equipment
FES	Future Energy Scenarios (FES)
GSP	Grid Supply Point
HV	132 kV and above
HVDC	High Voltage Direct Current
IBR	inverter-based resources
IEEE	Institution of Electrical Electronic & Engineers
IET	Institution of Engineering and Technology
ISP	Internet Service Provider
LCT	Low Carbon Technology
LFDD	Low Frequency Demand Disconnection
LoM	Loss of Mains
LV	240V single phase to 11kV three-phase
MV	33-132 kV
NEM	National Electricity Market
NGESO	National Grid Electricity System Operator
NPL	National Physical Laboratory
NVE	Norwegian water resources and Energy directorate
OBCM	On Board Charger Module
OEM	Original Equipment Manufacturer
Ofgem	Office of Gas and Electricity Markets
OLTA	Off-Line Transmission Analysis system
OpenDSS	Open Distribution System Simulator
OV	Over Voltage
PE	Protective Earth
PLL	phase-locked loop
PV	Photo Voltaic
RAG	Red/Amber/Green
REV	Resilient Electric Vehicle Charging
RoCoF	Rate of Change of Frequency
SPR	Scottish Power Renewables
SQSS	Security and Quality of Supply Standard
SVC	Static VAR Compensator
T&D	Transmission and Distribution
TO	Transmission Owner
TOTEM	Transmission Owner Tools for EMT Modelling
TV	Television
UFLS	Frequency Load Shedding
UKPN	UK Power Networks
UoB	University of Bristol
UoS	University of Sheffield
UV	Under Voltage
V2G	Vehicle to Grid
V2X	Vehicle to X (X = Building, Home, Load, Grid)
VS	Vector Shift
WEM	Wholesale Electricity Market
WP1	Work Package 1
WP2	Work Package 2
WPD	Western Power Distribution

CHAPTER 1
Introduction

This section introduces Sygensys and Project REV.

CHAPTER CONTENTS

SYGENSYS

Company Overview

Sygensys[1] is a start-up developing demand management and energy storage system solutions to allow effective use of renewable energy sources. Our vision is to leverage the incredible potential of bi-directional power flow from electric vehicles and battery energy storage systems to help balance electricity supply and demand, both on public grids and local microgrids.

Our solutions will provide a secure supply to domestic and industrial consumers even when electricity systems are hit by storm damage, equipment failure or cyber-attack.

Sygensys is developing patented technology to enhance the performance of Electric Vehicle (EV) charging and Vehicle to Grid (V2G) technology to improve grid resilience. We are working with a wide range of collaborators including grid operators, regulators, end users and semiconductor vendors to bring these innovative solutions to market.

Through Project REV, and other collaborative R&D activity, we will enable resilient demand side response, to provide reliable stability services which grid operators can depend on to balance the 100% renewable energy Green-Age Grid[2].

[1] www.sygensys.com
[2] Power Converters: A Growing Challenge to Grid Stability

This report highlights a wide range of potential issues, which working together we can address and enable EV charging and V2G to actively support grid resilience.

NETWORK INNOVATION ALLOWANCE

Project REV

Project Resilient Electric Vehicle Charging (REV)[1] is analysing the potential future impact of Electric Vehicle (EV) charging on electricity grid short-term (1 cycle to 10 seconds) frequency and voltage stability, and cascade fault prevention and recovery.

During Work Package 1 (WP1)[2], Project REV aimed to answer the question "How could EV charging make the grid less stable?" and went on to identify numerous mechanisms in a report. We highlighted the potential causes of, and need to effectively manage, the risks associated with mass adoption of EV, V2G and smart charging. These risks should be addressed by regulation, market design and standardisation activities alongside EV-based DSR system implementation.

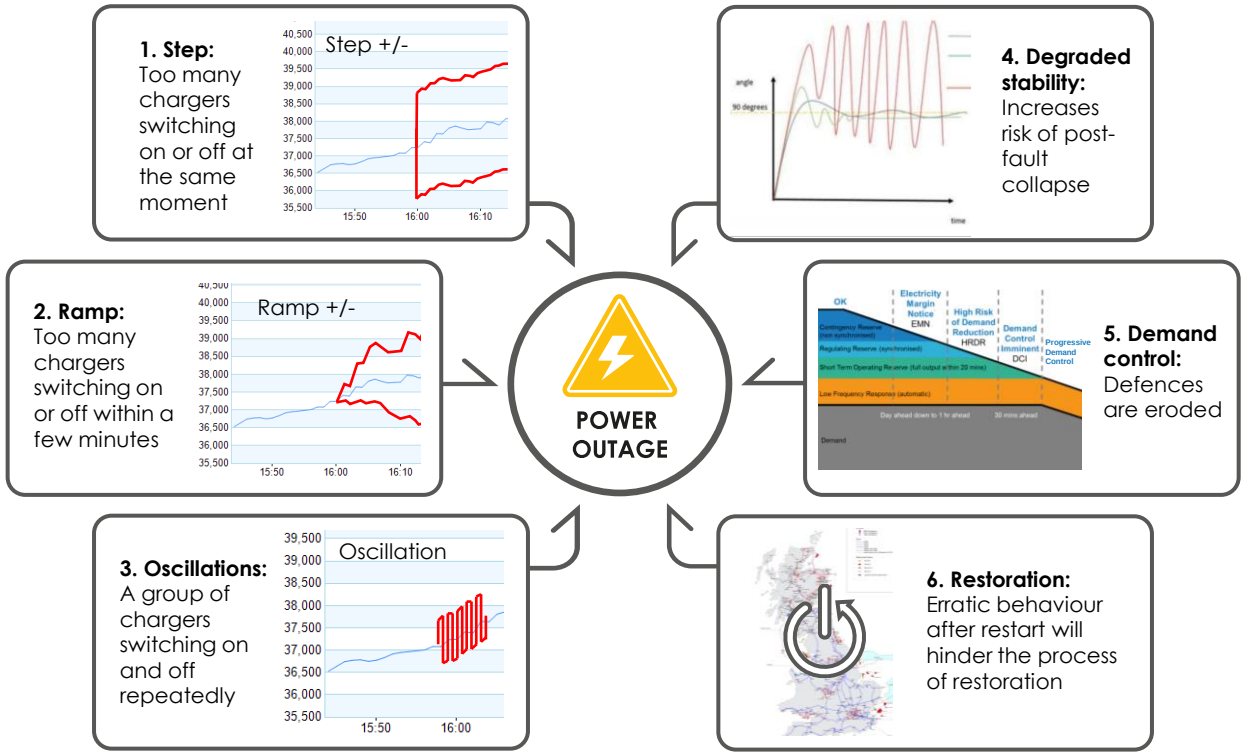
In WP2 we have undertaken simulation studies to explore a number of these issues related to grid stability including coincident tripping and the changing voltage sensitivity of loads. During these studies, we identified some limitations of existing load modelling.

We also analysed the issues identified in WP1, and this report presents a prioritised list and details of actions currently underway to address the issues. This report highlights how quickly smart EV Charging (EVC) and Vehicle to Grid (V2G) is likely to be adopted, the many benefits offered to both grid operators and consumers, along with some of the forecasting challenges in this rapidly evolving market.

This project has been funded by National Grid ESO through the Ofgem Network Innovation Allowance scheme project number NIA2_NGEOS006[1]

[1] Project REV on ENA Smarter Networks Portal
[2] Project REV WP1 Webinar

Key issues identified in Project REV work package 1



See the Work Package 1 report[1][2] for more details of these issues.

FUTURE TRENDS

The scale of EV charging

National Grid ESO's Future Energy Scenarios (FES) 2022[1] predicts a total available load from EVs of over 200 GW in the late 2030s. This is the total power that would be required if all EVs were charging at the same time. In reality this would never be seen, as consumers will choose to charge their vehicles at different times and many will not need to charge every day. This is fortunate, as the potential demand vastly exceeds current network capacity [2]. Exceptional situations, such as restoration of supplies after a multi-day power outage, could lead to exceptionally high demand from EV charging.

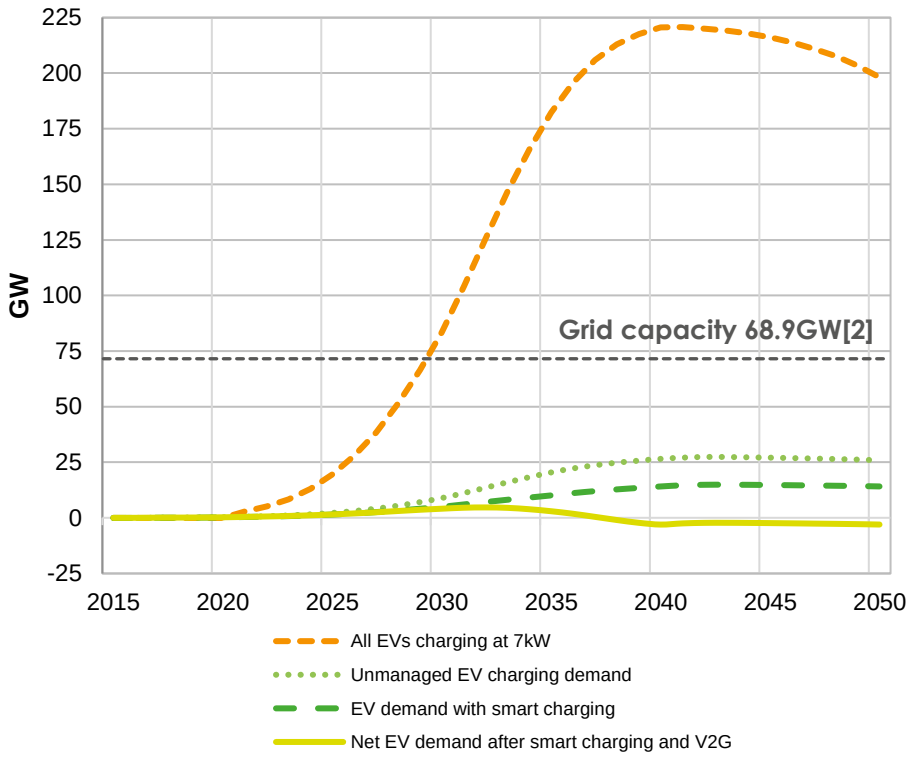
If unmanaged (non-smart) charging were widely adopted, the forecast weekday evening peak power requirement for EVC is up to 25GW. This represents a diversity factor of 0.125 with approximately 1 in 8 EVs charging at the peak.

The challenge for grid operators is not only to meet the demand for power, but also accurately match generation to demand second by second. Diversity in the timing of demand changes is critical to grid operability. If 1% of EVs in the late 2030s were to start charging at the same instant, that would create a load step of over 2GW which could have a massive impact on grid operability.

Evening peak is the time of day at which wholesale energy costs are typically highest. Smart charging systems will respond to these costs and, where possible, delay charging to periods of lower cost energy. This helps reduce peak demand. Further to this, V2G may allow EVs to provide power to the grid at peak times. The graph shows a 17GW peak demand reduction when V2G capability is added to smart charging.

Project REV is focused on EVs, however much of the analysis in this WP2 report applies to a wide range of smart Distributed Energy Resources (DERs), not just EV and V2G. Heat pumps, for example, are predicted to be another rapidly growing load on the grid. These will also be controlled by flexibility systems, to help reduce peak load on the grid.

The importance of EV charging diversity. Total EV capacity compared to EVC evening peak.



[1] Future Energy Senarios 2022 - Consumer Transformation Scenario | National Grid ESO
[2] UK: Energy transmission network capacity 2021

Timing diversity for consumer loads is critical for grid operation. This must be maintained in smart charging systems.

THE WORK PACKAGE 2 REPORT

Objective of WP2 studies

Project REV WP1 raised a wide range of issues which could arise from the mass adoption of smart EVC and V2G. This WP2 report builds on the findings of WP1. However, it should be noted that WP2 does not address all of the issues raised in WP1, instead it concentrates on a few specific topics where more detailed analysis was required to gain a deeper understanding of the issue.

We have used analysis and grid simulation studies to investigate the impact of mass EVC and V2G on the system stability in the 0 to 10 second time period. This demonstrates how small-scale, distribution-connected, behind-the-meter resources can impact stability at a national transmission level.

This report is split into the following chapters:

- RoCoF and vector shift
- Under and over voltage
- Stability analysis and modelling
- The benefits of smart charging and V2G

This activity added detail to aspects of the WP1 report findings, and also identified any limitations of simulation tools and models. The report explores the potential financial benefits of smart charging and V2G and looks to identify factors which may influence the benefits of these systems.

At the end of each section, a series of findings and recommended next steps are presented. These are prioritised on a Red/Amber/Green (RAG) scale. See right.

Prioritization

1

Each recommendation will be shown in a rectangular box on the **left of the page at the end of each chapter.** This colour box denotes an essential action.

2

This colour box denotes a desirable action.

3

This colour box denotes an optional action. This is shown in the key below.

ESSENTIAL ACTION DESIRABLE ACTION OPTIONAL ACTION

This WP2 report has been written for NGESO. The analysis is focused on meeting their needs. The underlying issues raised in WP1 have broader impact across the industry

INTRODUCTION

Tools used in WP2 studies

WP2 relates to the impact of LV-connected EVC and V2G assets on the HV transmission system. This required investigating how a range of simulation tools, including NGESO's current analysis suite, could be applied outside their normal use cases.

For the WP2 studies, the Project REV team had access to and support using the National Grid ESO Off-Line Transmission Analysis system, referred to as "OLTA". This is used for load flow (static) and phasor-based (rms) simulation within Digsilent PowerFactory. NGESO use it for design, planning and optimization studies from 10 years ahead down to hours ahead in the control room. This tool has been in use for about 15 years.[1]

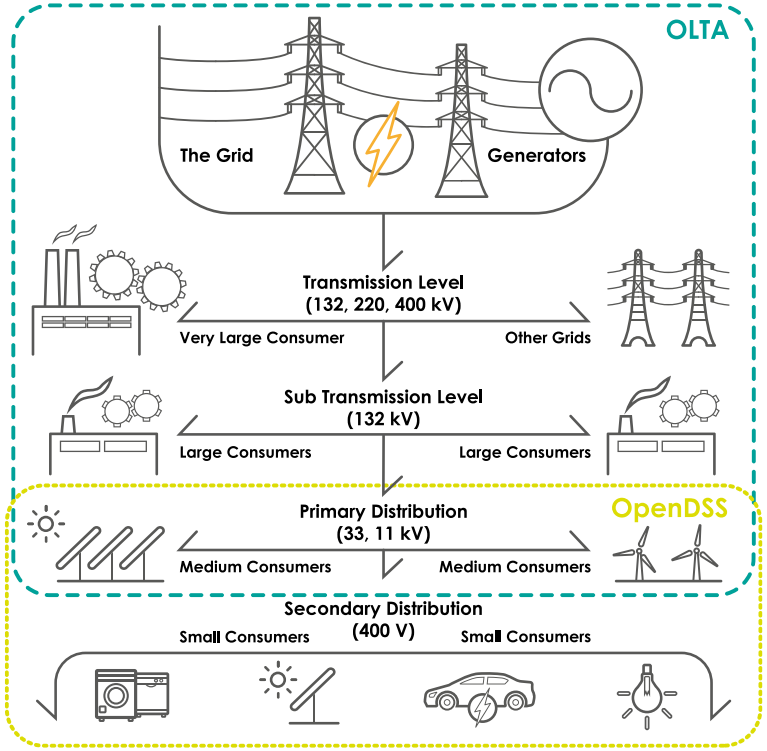
The OLTA model covers the full GB transmission system at 400, 275 and 132 kV and includes HVDC links. It also includes some parts of the distribution MV system down to 33kV. This model is useful when considering wide-area phenomena, for example related to frequency, rate of change of frequency (RoCoF) and voltage.

In OLTA, loads are modelled as aggregated demand at both Grid Supply Points (GSPs) and within the MV distribution system. However, EVC and V2G are typically connected at LV (400/230V), so for some studies we needed to model down to the LV level in the distribution network - for example, to study the 'last mile' voltage drop across distribution feeders, which has a major impact on system performance.

For this purpose, we used OpenDSS with a representative MV/LV network model[2] including approximately 150,000 individual LV connections. The OLTA and OpenDSS simulations were undertaken separately; there was no attempt at co-simulation or co-modelling – these challenges are described in [3].

During this process looking at emerging challenges to the system, we have identified some potential limitations of current NGESO modelling techniques and the need to enhance capabilities in future to help analyse the impact of mass adoption of EVC and V2G.

Transmission and distribution modelling tools



[1] Timeline for OLTA introduction
[2] Hybrid European MV-LV Models for Smart Distribution Network Modelling
[3] Impact of IEEE 1547 Standard on Smart Inverters and the Applications in Power Systems

Mass EV adoption is a challenge for modelling tools across transmission and distribution.

ACKNOWLEDGEMENT

Analysis Process

A key objective of Project REV is to identify and assess the mechanisms which may impact short-term grid stability and recovery from incidents. This has been undertaken through a series of brainstorming sessions in WP1 and system studies and analysis in WP2, with input expertise and data from industry sector experts from organizations including:

- Sygensys – Project lead
- National Grid ESO (NGESO)
- Energy System Catapult (ESC)
- Energy Networks Association (ENA)
- UK Power Networks (UKPN)
- Electric Power Research Institute (EPRI)
- Western Power Distribution (WPD)
- National Physical Laboratory (NPL)
- Norwegian water resources and Energy directorate (NVE)
- Scottish Power Renewables (SPR)
- University of Bristol (UoB)
- University of Sheffield (UoS)

We thank all contributors for sharing their knowledge. This report has been produced by Sygensys based on the input from a broad range of contributors, but it may not reflect the views of those organizations or the individual participants.

We would welcome feedback from NGESO on the findings in this report, as well as from participants in the EV charging supply chain including vehicle and charge point designers and manufacturers, operators, aggregators and DNOs. Going forward we are keen to collaborate to address the issues raised within this report.

For any inquiries regarding this document please contact: rev@sygensys.com

CHAPTER 2

RoCoF and Vector Shift

This section describes issues related to Loss of Mains protection based on RoCoF or Vector Shift, and highlights the need for a mandatory vector shift fault ride-though specification for DER.

CHAPTER CONTENTS

RoCoF and VECTOR SHIFT

Frequency and phase-based Loss of Mains detection techniques

Loss of Mains (LoM) protection is an important function within Distributed Energy Resources (DER). It is a key safety feature that stops the generator delivering power if it becomes disconnected from the grid. This helps reduce the risk of electric shock and damage to equipment. LoM may occur directly at the point of connection of the generator, or may occur if a small region of the grid (otherwise known as an island) becomes disconnected from the bulk power system. LoM protection must, however, not operate at the wrong time as it will reduce available generation capacity.

Historically, Rate of Change of Frequency (RoCoF) and Vector shift (VS) were accepted forms of LoM detection for DER connected to the GB grid. As the capacity of inverter-connected renewable generation connected to the GB grid has increased, both the inertia and short-circuit level from synchronous machines such as coal-fired steam turbines has fallen. This led to larger frequency changes and vector shifts during system disturbances.

The use of VS-based LoM detection can lead to embedded generators tripping rapidly after a system disturbance. This so-called “coincident tripping” is highly undesirable because it creates a significant risk of cascade failure; this risk has been recognised since at least 2012[1].

From 01/02/2018, VS was disallowed as a form of LoM protection[2] and the limit for RoCoF protection was raised from 0.125Hz/s to 1Hz/s with a 500ms duration[3]. This was as high a level as was reasonably possible, to avoid coincident tripping in a low inertia system whilst maintaining safe operation[4]. The ALoMCP[5] funding programme was introduced to help operators update existing generators to the new setting.

The importance of this change was highlighted on 9 August 2019 [6] where there was significant loss of supply involving coincident tripping. 500MW of distributed generation tripped, of which 150MW was due to VS protection and 350MW was due to RoCoF protection set at the old limit of 0.125Hz/s.

Retrospective change can be expensive and time-consuming.

In 2012[1], inappropriate LoM protection thresholds were identified as a serious threat to system security.

10 years later, it has so far cost £29m in direct payments to update generator protections at 8,845 sites and £4.1m expenditure in programme administration and delivery[7]. There have also been substantial additional balancing costs to manage the coincident tripping risk.

The projected saving in the balancing costs from this program is £20.0m per annum[7].

We need to design and implement robust and grid-friendly smart charging systems now, because updating 10 million plus EV chargers retrospectively would be a daunting, if not impossible, challenge.

[1] Frequency Changes During Large Disturbances
[2] GC0079: Frequency Changes during Large Disturbances and their effect on the total system
[3] Engineering Recommendation G99 Issue 1 – Amendment 1
[4] Assessment of Risks Resulting from the Adjustment of ROCOF Based Loss of Mains Protection Settings
[5] The Accelerated Loss of Mains Change Programme (ALoMCP) | National Grid ESO
[6] | National Grid ESO LFDD 09/08/2019 Incident Report
[7] ALoMCP Window 9 Report

Early regulatory action is needed to avoid having a large installed base of under-performing equipment which adds to grid operation costs.

RoCoF

RoCoF detection challenges

ER G99 defines the detection threshold for RoCoF and a specific test method and limits[1]. However, these tests are based on a pure sinewave signal; in the field, relays may also be subjected to harmonics, phase imbalance and noise. RoCoF events may also happen simultaneously with a voltage event, and some incidents may produce a step change in phase, otherwise known as a vector shift. All of these factors may influence the value of RoCoF measured by the relay.

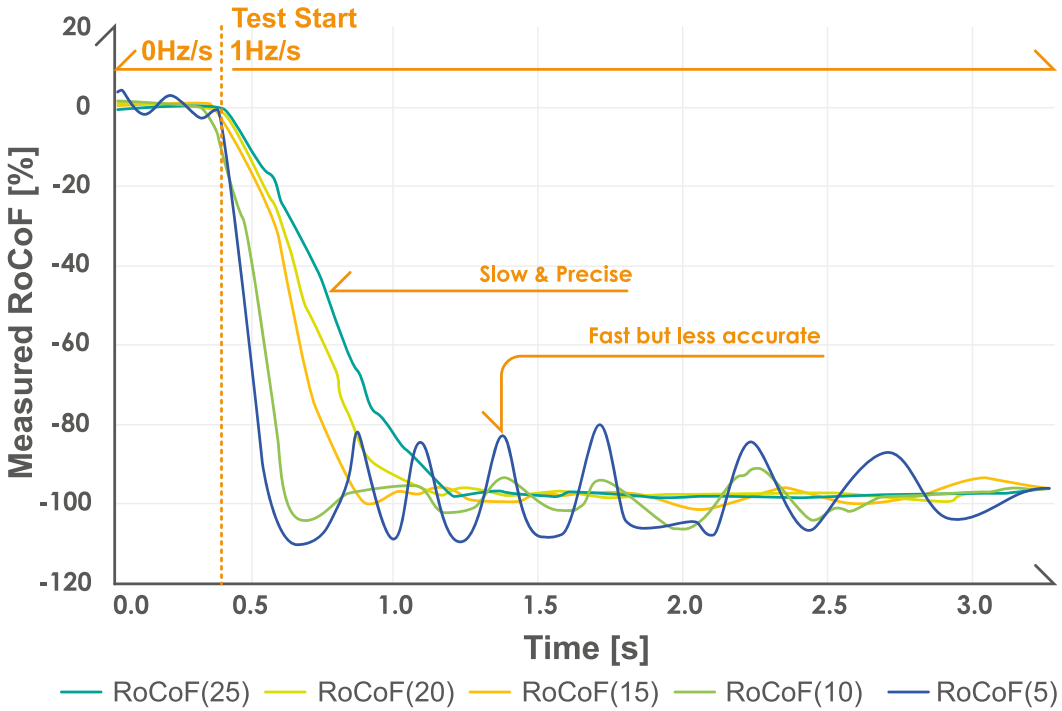
Relay manufacturers design and implement their RoCoF detection algorithms both to pass the regulatory tests and to operate with the imperfect signals encountered in real-world conditions.

For example, a low-pass filter may be used to reduce the impact of noise and harmonics. Design of these filters involves compromise; narrow bandwidth filters are good for noise reduction and accuracy, but increase the delay, slowing the speed of LoM detection.

Not all products use the same algorithm, as this is not defined in the standard. Some products have been known to have issues[2]. The graph on the right shows the effect of one particular parameter in one type of relay: the number of cycles used to calculate the average ("filtered") value of RoCoF. When there is a step change in RoCoF from zero to 1Hz/s, averaging over five cycles ("RoCoF(05)") gives a fast tripping response but with a less accurate tripping threshold, whereas averaging over 25 cycles ("RoCoF(25)") gives a more precise threshold but slower operation.

The variations between manufacturers' products can lead to a significant difference in performance, such that for a group of generators connected at the same Grid Supply Point with the same nominal RoCoF protection settings, some generators might trip and others remain connected for a given power system disturbance. Similarly, tools used for modelling grid behaviour will also use an algorithm to calculate RoCoF, and it can be important to have an understanding of how they operate.

Impact of filter length (in cycles) on the speed of response and accuracy of a RoCoF detection algorithm.



[1] Engineering Recommendation G99 Issue 1 – Amendment 1 sections 10.6.7.1 and 15.4.1
[2] VS LoM relay issues, Presented at The Distribution Code Review Panel Meeting, 8 March 2017

The algorithms used to calculate RoCoF have a significant impact on product performance.

RoCoF

Regional variation of RoCoF

In the following section of this report we have investigated RoCoF effects. As a base test case, we took the loss of infeed from an interconnector on the south coast as a typical cause of negative RoCoF (falling frequency). It should be noted that a positive RoCoF (rising frequency) will be caused by a sudden loss of load or outfeed.

The frequency of a synchronous grid is normally considered to be a system-wide parameter. However, over a short period of time, phase variations across the grid can lead to slight differences in instantaneous frequency. This leads to variations in RoCoF across the system. The location of the highest RoCoF measured over a 500ms period (as specified in sha [1]) may not be physically close to the original incident. As a result, and counter-intuitively, generators with RoCoF protection may trip at a significant distance from the fault rather than close by.

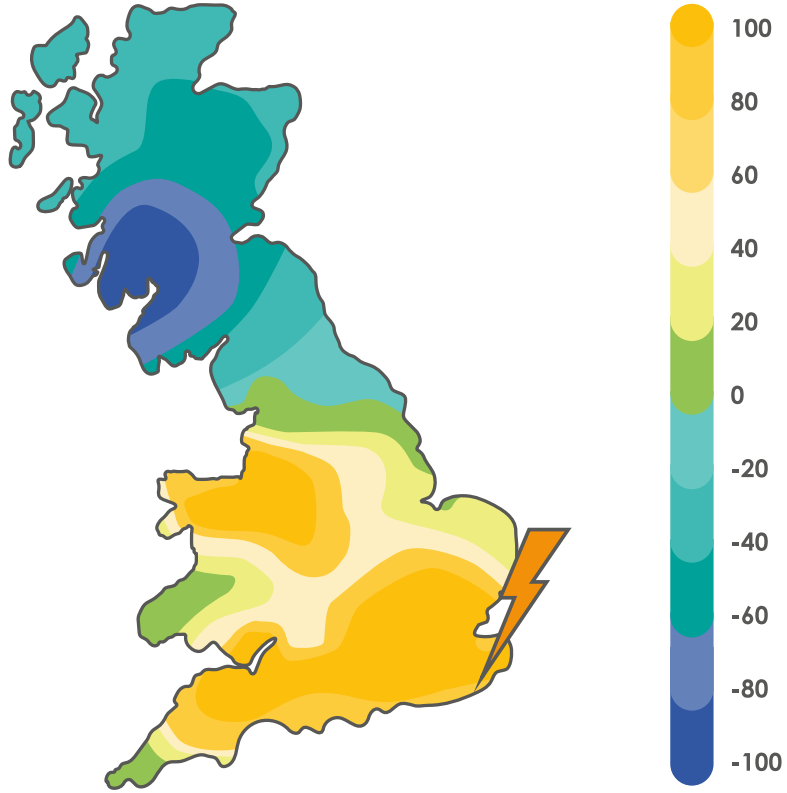
It is possible that some regions will encounter a RoCoF that is noticeably higher than the average measured on a national basis. This regional effect has been recognised by National Grid, for example within the EFCC project[2].

The regional impact will be dependent on the type, location and size of the original incident and the grid operating conditions at the time – particularly the regional distribution of inertia and fast frequency response. It is therefore important during system security studies to either model this effect or allow some margin against the protection threshold if a national calculation of RoCoF is used.

Modelling generators with RoCoF protection at multiple locations across the grid can help show the potential for tripping to occur in some locations well before the average level of RoCoF reaches the G99 threshold. This could then trigger cascade tripping.

[1] Engineering Recommendation G99 Issue 1 – Amendment 1
[2] The Enhanced Frequency Control Capability (EFCC) Project - slide 14

Map showing the regional variation in RoCoF as a percentage of peak RoCoF



RoCoF is not a system-wide parameter, it is specific to a location.

RoCoF

Inter-area oscillation impact on RoCoF tripping

In a large synchronous grid there can be the potential for inter-area oscillations, with a cyclic variation in power transfer between two regions following a disturbance. This variation in power transfer leads to a variation in phase, frequency and RoCoF between the regions.

The presence of these oscillatory modes may be seen clearly during recovery from a large incident, but the system is managed in such a way that the magnitude and duration of these oscillations is kept to an acceptable level.

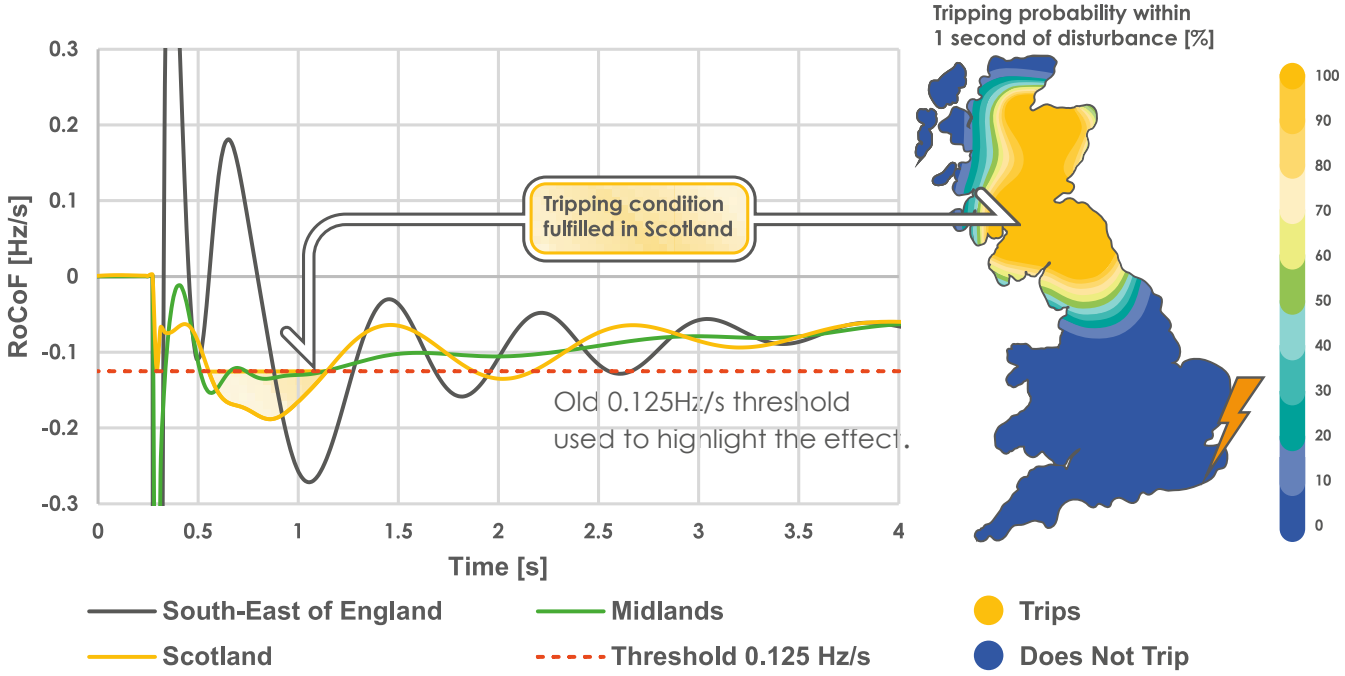
A well-known example on the GB grid is a North-South oscillation which can limit the level of safe power transfer between Scotland and England. This oscillation can be observed in simulations and in recordings of actual events. The precise characteristics of this oscillation (amplitude, frequency and damping) will depend on operating conditions such as the generation mix, load level and power transfers, so will vary hour by hour.

Recent research[1] using a simplified model of the GB system has shown that if the inter-area oscillation mode has a frequency lower than 1 Hz, it can have a significant impact on RoCoF detection. A generator in one region may experience a sustained RoCoF above the national average for the half cycle period (>500ms) of the inter-area oscillation, triggering "premature" RoCoF tripping; see the yellow shaded area on the graph. Conversely, a generator affected by a local, faster oscillation (>1Hz frequency so <500ms half period) could experience "re-setting" of the RoCoF detection which would then prevent tripping, as can be seen in the grey line on the graph.

This effective variation in threshold can help explain tripping at a distance from the event that caused the RoCoF.

[1] A Novel Hardware-in-the-Loop Approach to Investigate the Impact of Low System Inertia on RoCoF Relay Settings

Simulation of HVDC link trip in South-East of England, 1000 MW loss, causing tripping in Scotland (Reduced GB model)



Sustained RoCoF of sufficient duration to trip generators may only occur away from the location of the disturbance.

SYGENSYS

RoCoF

Cascade tripping sequence

At first it may appear that a few small DER generators tripping coincident with a large incident is not a major issue. The loss of generation capacity will only have a small impact on the power balance in the grid. However, this loss of capacity can add to the initial incident and increase the risk that available reserves will not be adequate to compensate for the losses. It is especially a concern after a large initial loss of infeed (generation) or outfeed (load).

Coincident tripping may lead to a longer period of sustained RoCoF and/or a higher value of RoCoF, which then has the potential to cause further generators to trip. Ultimately this can lead to a cascade event and loss of supply for some consumers.

This risk formed a significant part of the justification for changing the RoCoF threshold by G99 from 0.125 Hz/s to 1 Hz/s to allow for the growth in inverter-based PV and wind generation which do not contribute to inertia.

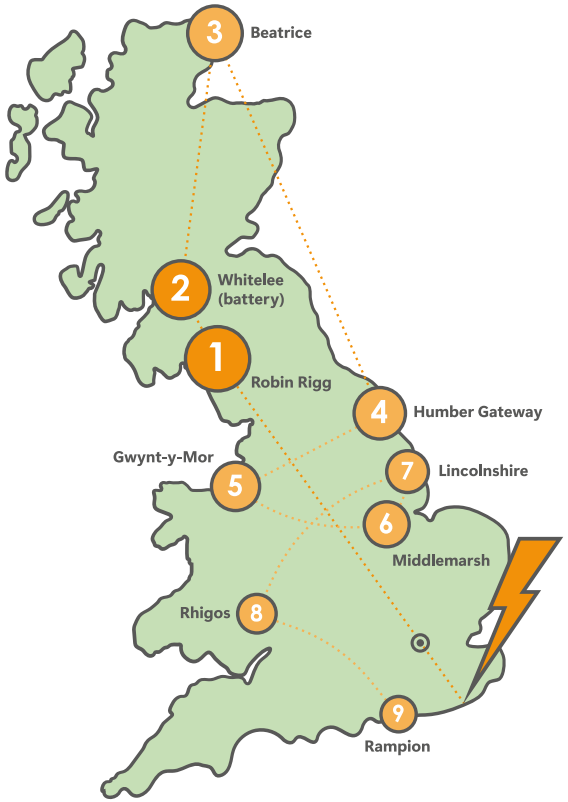
"The proposals prevent the need for mitigating actions such as the constraint of largest infeed and **the constraint of asynchronous generators**."[1] (in this context, "asynchronous" refers to inverter-based generators).

The study result right shows a simulated V2G cascade event on a full OLTA model of the GB transmission system. This is an artificial test case with RoCoF protection relays with a low threshold added to a number of existing 100MW wind farms (plus one battery site). The low RoCoF threshold setting was used to demonstrate the tripping sequence. The event was initiated by a simulated 500MW infeed loss.

Loss of infeed from the interconnector caused sequential tripping of generators around the country, as shown in the numbered sequence of events. Counterintuitively, tripping does not start close to the original incident. In normal operating conditions, the levels of inertia must be sufficient to prevent this happening.

[1] Frequency Changes during Large Disturbances and their Impact on the Total System

Simulated cascade tripping sequence (full GB model)



Tripping of small DER generators has the potential to contribute to a cascade event across the GB grid.

RoCoF

Data related to high RoCoF events for post-fault analysis

As part of Grid Code modification activity GC0105 and GC0151, National Grid ESO are publishing data[1] on a range of system incidents. This allows generator operators and other users of the grid to gain a greater understanding of the challenges faced in managing incidents on the grid as levels of renewables increase and check the performance of their assets, recorded by their local measurement equipment, coincident with these events.

On 16 May 2022 there was a coincident trip and part de-loading of two interconnectors leading to a 1481MW loss of outfeed. This resulted in a peak reported RoCoF of +0.202 Hz/s. This is well below the protection threshold of 1Hz/s specified in G99 for V2G and other embedded generation.

At that specific time, with that level of RoCoF, the risk of coincident tripping of DER was low as RoCoF only reached 20% of the threshold. Whilst the 1Hz/s RoCoF threshold should give a considerable safety margin for some years to come, if inertial services are procured in the future to “just” meet this threshold, local RoCoF variations should be modelled to ensure system security.

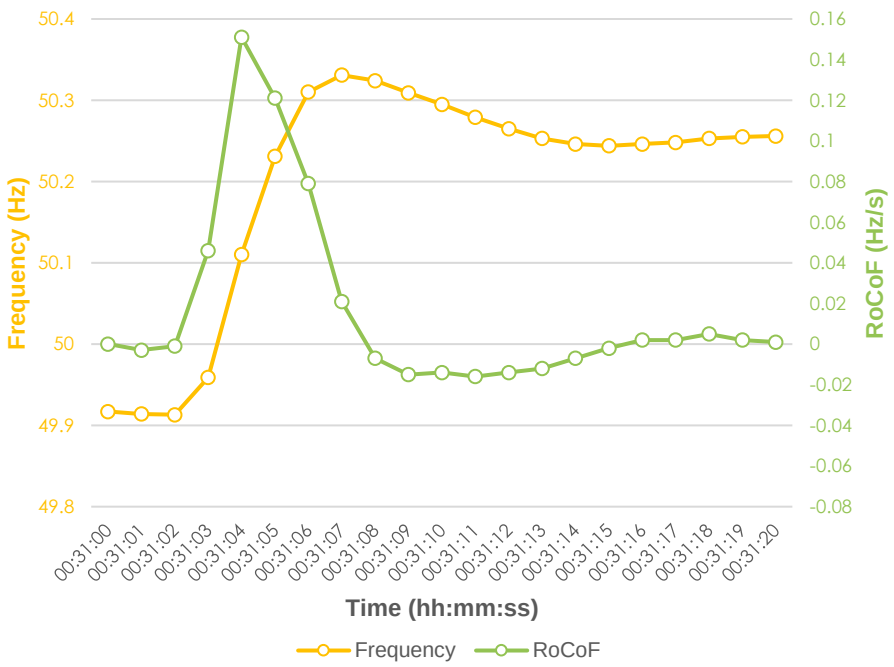
Limitations of the current data published by NGESO including [1] and [2] are:

- Frequency data published is 1 sec rate, which does not allow assessment of the 500ms RoCoF limit
- One frequency is reported for whole country; this does not allow calculation of regional RoCoF effects
- The reported RoCoF is not consistent with the associated figures for inertia and infeed/outfeed loss. See note right.
- Voltage waveforms are generally not available, so this does not allow detailed investigation such as [3] including investigation of potential impacts of combined vector shift or voltage disturbances simultaneous with RoCoF events.

Wider availability of more extensive data would help grid Users, equipment manufacturers and academic researchers.

[1] GC105 & GC151 System Incidents Reports
[2] ESO Data Portal: Home | National Grid Electricity System Operator
[3] Example of use of waveform data for incident investigations: Texas Event: March 22, 2022

Public data[1][2] at one second resolution limits the analysis of RoCoF events.



Note that from the 1s reported data, the calculated peak RoCoF is only 0.151Hz/s as above. The NGESO summary table gives 0.202Hz/s based on non-public higher resolution data, whilst the theoretical value of RoCoF (calculated from the reported inertia and infeed loss) would be 0.252Hz/s.

High time resolution data is essential to allow successful post-fault analysis for RoCoF events.

RoCoF

The RoCoF threshold and its impact on inertia requirements and restoration

As a result of increasing renewable inverter-connected generation, “Costs and volume of actions have been increasing year on year due to an increase in the number of low inertia periods and higher wholesale costs with approx. £100m spent in the last year to manage inertia” [1]

In the future, National Grid ESO is therefore planning to be able to operate the grid with lower inertia, such that RoCoF should not exceed 0.5 Hz/s [2]; see box right. This has only been possible because of the change of RoCoF limit to 1 Hz/s and the ALoMCP which has funded generator operators to make retrospective changes. There will remain a good margin between the maximum planned RoCoF, 0.5Hz/s, and the nominal tripping threshold, 1 Hz/s, providing allowance for regional and device variations.

RoCoF is also important during system restoration, or "black start" - the process of repowering the grid after a regional or system-wide power outage. In a given area, the process starts from a single anchor generator which repowers a small part of the network, referred to as an "island". This is gradually expanded, adding blocks of load and generation to restore the system.

The island system will be resource limited with potentially very low inertia. During block loading, unusually large RoCoF events and rapid voltage excursions may occur, potentially simultaneously. Within the Distributed Restart program [1], a design margin has been proposed with a recommended operational RoCoF limit of 0.8 Hz/s. Further work may be required to assess the ride-through capabilities during restoration of LV-connected devices including EVC and V2G.

Reference [3] states “It is assumed that any existing DSO Under Frequency Load Shedding (UFLS) and Over Frequency Generation Shedding (OFGS) can be disabled or set to wide limits for the island operation period, so the relevant limits are also related to DER G99 recommendations.” It should be noted that G99 includes the new mandatory under-frequency response for BESS, which could be highly beneficial during restoration, helping reduce the risk of under-frequency system collapse.

[1] ESO Operational Transparency Forum 24 August 2022
[2] Operability Strategy Report December 2021
[3] Assessment of Power Engineering Aspects of Black Start from DER - Section 3.1.1

Operating the GB grid with lower inertia and higher RoCoF

“Today we ensure system inertia is always above 140GVA.s. Going forward minimum system inertia could be as low as 96GVA.s for zero carbon operation by 2025. Our studies indicate that if we have a 1.8GW largest loss on the system and we need to limit RoCoF to less than 0.5Hz, this means we need to keep inertia above 90GVAs. If we assume the largest loss on the system is ~6GVAs (corresponding to a 1800MW largest loss), this means our pre-fault inertia needs to be kept above 96GVAs.”

“Our future forecasts show that system inertia is likely to drop below this requirement in the next few years. This is part of the driver for the stability pathfinders as they are buying the system inertia needed to meet our requirement.” [2]

As inertia falls, we need to make sure RoCoF remains below generator tripping thresholds with an adequate margin.

VECTOR SHIFT

Vector Shift Ride-Through

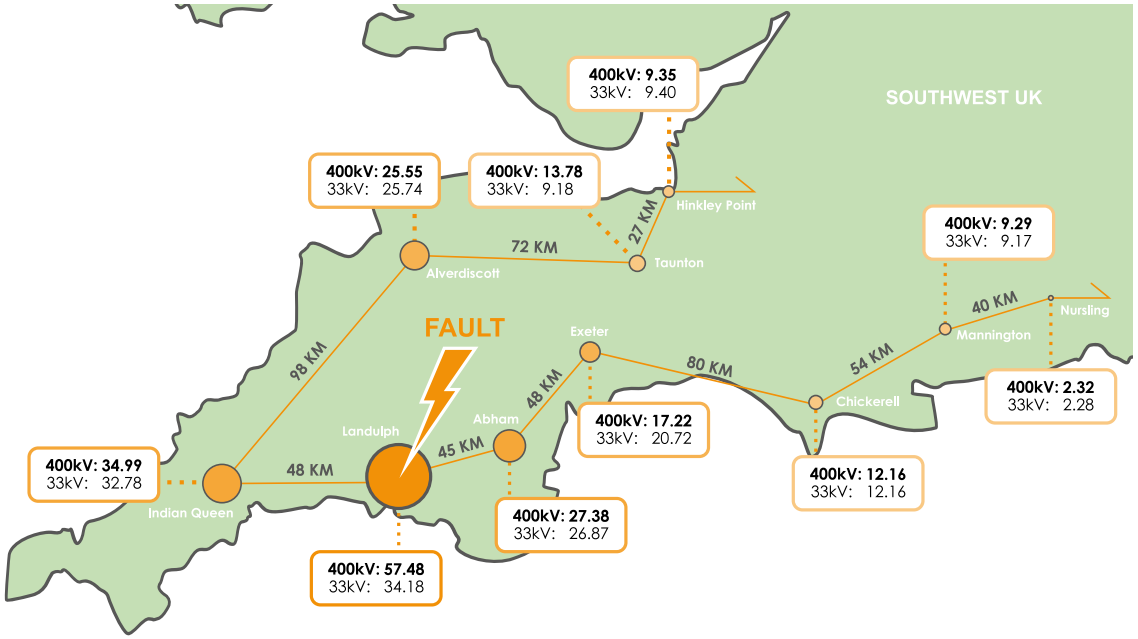
"In May 2016 WPD suffered a wide-spread loss of distributed generation as a result of Vector Shift Loss of Mains protection operation in the South-West licence area."[1] The map shows an example of the area that can be impacted by VS for a single incident. Away from the fault, at each location the VS at HV transmission and MV distribution is almost identical. At this time, most VS protection was set to a threshold of 6 degrees. In 2018 when VS protection was disallowed, a corresponding VS ride-though requirement of +/-50 degrees was proposed [2], but currently has not been reflected in the mandatory requirements for generators in G99. Confusingly, however, it is included within the recommended protection system type tests.

The ALoMCP has reduced the number of generators with 6 degree VS protection, however some sites have not been updated, so a risk remains[6]. Mitigation of this risk requires additional reserve holding. There is, however, no allowance in [6] for generators without VS protection tripping on large VS events. This could be due to Phase-Locked Loop "unlock" or spurious frequency calculations leading to under- or over-frequency tripping.

All converter-connected generators, including V2G, will ultimately trip at some level of VS, but the required ride-through performance is currently not clearly defined. One report shared with GC0155 [3] members showed an example of a wind farm generator tripping with VS ~20 degrees which, if seen for mass V2G, would be a major concern. **By the time of mass adoption of V2G, we would anticipate that adequate VS ride-though performance should be mandated.**

The topic of vector shift ride-though capability for loads is rarely discussed. Historic load types have no mechanism by which they would de-load due to VS. By contrast, it is possible that software-controlled power converters used in loads such as EV OBCM could potentially de-load for a short period if subject to a major VS event. Due to time limitations, the Project REV team have not investigated this issue.

Vector shift in degrees across a region around a fault, [4][5]



[1] Inadvertent Operation of Loss of Mains Protection
[2] DC0079 Frequency changes during large disturbances and their impact on the total system
[3] SCOTTISH POWER RENEWABLES 05/07/2022 GC0155 Phase Jump Evidence - Private communication
[4] GC0079: Frequency Changes during Large Disturbances and their effect on the total system - Phase 1 & 2 | National Grid ESO: meeting 8 Mar 2017
[5] Map of VS disturbance
[6] Frequency Risk and Control Report 2022

It is essential that the vector shift fault ride-though required for grid security is defined within regulations.

VECTOR SHIFT

Vector Shift impact on inverter-based resources

Like synchronous machines, inverter-based resources (IBR) such as V2G must track the phase of the grid during a contingency event. This helps ensure that current delivery to the grid is in phase with voltage. Typically, IBRs will use a phase-locked loop (PLL) which provides a local internal phase reference that is kept in synchronisation with the grid.

For rapid changes in phase, a synchronous machine may suffer pole-slip. The equivalent for an IBR is that the PLL suffers an “unlock” condition, where the phase of the PLL is no longer successfully tracking the phase of the grid. The tracking performance of a PLL is determined by its algorithm design and can be very different from one product to another. IBR PLLs may become unlocked for a grid phase step of as low as 15 degrees, whereas in other products the PLL may successfully ride through phase jumps of up to 90 degrees or more[1].

Concerns over the capabilities of PLLs to track phase during a disturbance are well known. For example, see right; this is an event from the USA[2] where PLL loss of synchronisation was the main cause of coincident tripping. A lack of inverter-level oscillography data significantly limits the ability to conduct detailed analysis on this type of tripping to identify if PLL loss of synchronism is due to vector shift, voltage sags or a combination of both.

Optimising PLL design within inverter-based resources involves many trade-offs[3]. These relate to both voltage and phase jump ride-through requirements, plus the combination of system strength and any requirement for fault current injection during under-voltage conditions.

If an IBR trips because of a vector shift, there is the potential for a range of error messages, from the obvious PLL Unlock or Loss of Sync to a wide range of others, which may in part be due to PLL error, for example;

- AC Over-Current, which can be caused by the inverter delivering current out of phase with the grid due to PLL phase tracking errors. This could lead to injection of reactive power leading to an over-voltage error message.
- Under- or Over-Frequency, as the PLL may be used within the frequency detection algorithm.
- Loss of Mains or RoCoF, as a phase step may impact the RoCoF measurement accuracy.

[1] Behaviour of distributed resources during power system disturbances: AEMO
[2] Odessa Disturbance Report
[3] Optimal control setting and PLL types

PLL Loss of Synchronism is a well known issue for IBRs

Cause of Reduction	Reduction [MW]
PLL Loss of Synchronism	389
Inverter AC Overvoltage	269
Momentary Cessation	153
Feeder AC Overvoltage	147
Unknown	51
Inverter Underfrequency	48
Not Analyzed	34
Feeder Underfrequency	21

Odessa Disturbances Texas May 9, and June 26, 2021 [2]

Some IBRs are very sensitive to vector shift, leading to a risk of coincident tripping.

RoCoF AND VECTOR SHIFT

Recommendations

1

Grid operators need to allow margin for variations in regional RoCoF and in product RoCoF algorithm performance, for normal operation and during restoration. **Use of the full 1 Hz/s RoCoF range should be avoided.**

2

Vector shift fault ride-through to be specified in regulations. For example, via GC0155

3

Implement improved grid RoCoF (and vector shift) monitoring and data sharing **going beyond GC0105/GC0151**

ESSENTIAL ACTION DESIRABLE ACTION OPTIONAL ACTION

Bullet points from slides

- Early regulatory action is needed to avoid having a large installed base of under-performing equipment which would add to grid operation costs.
- The algorithms used to calculate RoCoF have a significant impact on product performance.
- RoCoF is not a system-wide parameter, it is specific to a location.
- Sustained RoCoF of sufficient duration to trip generators may only occur away from the location of the disturbance
- Tripping of small DER generators has the potential to contribute to a cascade event across the GB grid.
- As inertia falls, we need to make sure RoCoF remains below generator tripping thresholds with an adequate margin.
- High time resolution data is essential to allow successful post-fault analysis for RoCoF events.
- It is essential that the vector shift fault ride-though required for grid security is defined within regulations.
- Some IBRs are very sensitive to vector shift, leading to a risk of coincident tripping.

Introducing a vector shift ride-through requirement is necessary to ensure system security.

CHAPTER 3

Over and Under Voltage

This section explores the impact of under and over voltage protection in ECV and V2G systems, including coincident tripping.

CHAPTER CONTENTS

INTRODUCTION

EVC and V2G operating voltage range

In this section we consider how EVC and V2G over- and under-voltage protection combined with grid voltage excursions could have an impact on grid operability.

Electrical products are designed to operate over a specified voltage tolerance range. This is related to the voltage tolerance of the power supplied by the electricity utility. Products may fail to operate correctly if the voltage is too low or too high and may even be physically damaged.

In EV charging systems connected to the GB grid, the EVSE will typically include under- and/or over-voltage protection. This voltage protection is typically used to protect sensitive electronics from damage during over-voltage conditions, prevent the risk of serious mal-operation including over-heating during low voltages and may form part of the safety system aimed at preventing electric shock. The OBCM may also include separate under- and over-voltage protection.

As an example, consider the short dips in the voltage supplied to the EVC that may be experienced occasionally. Typically this occurs while grid protection systems are clearing a fault. Some product regulations define requirements for low voltage fault ride-though which are aimed at ensuring that the most common forms of voltage dips do not adversely impact the consumer experience. This does not necessarily mean continuous product operation. Regulations may allow products to pause or reset and auto-restart. This is common for some EV charger systems and would not normally even be noticed by the consumer.

V2G is considered a generator in terms of the Grid Code, and voltage-based protection is mandated as part of a broader protection system via G99[1]. The vehicle must stop providing power to the grid when voltage is outside predefined limits for set durations. This helps support safe operation of the grid and prevents unplanned island formation.

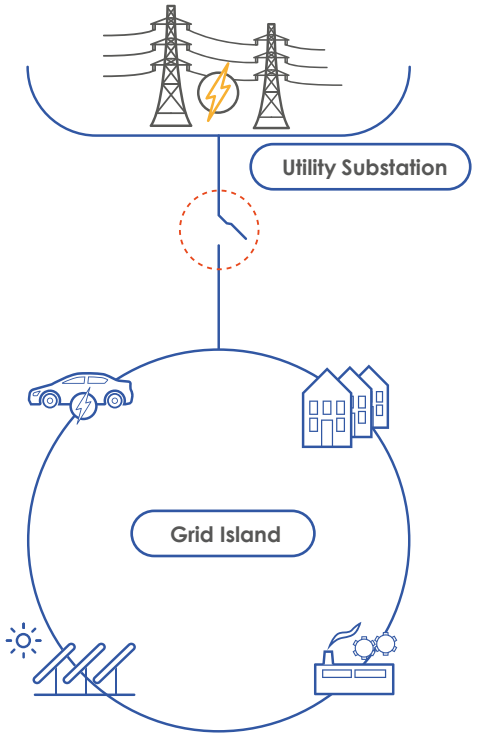
A section of the grid isolated from the bulk power system is known as an island

Detection of unplanned islands is important for:

Personal Safety
If a generator feeds power to disconnected lines, there is a public and worker safety risk from downed lines.

Power Quality
Island power regulation may be ineffective.
Power disruptions and instability are more likely.

Equipment Damage
Voltage and frequency fluctuations may cause damage to utility and customer equipment.



[1] Engineering Recommendation G99 Issue 1 – Amendment 8

Voltage-based protection is used both on EVC and V2G to help support safe operation.

INTRODUCTION

Typical voltage distribution at the point of connection

Most EVC and V2G will be connected to the LV network at 230V single-phase or 400V 3-phase. For this analysis we will consider typical 7kW-rated domestic products connected to a single-phase supply, but a large proportion of the analysis is also applicable to 3-phase connections such as forecourt rapid chargers.

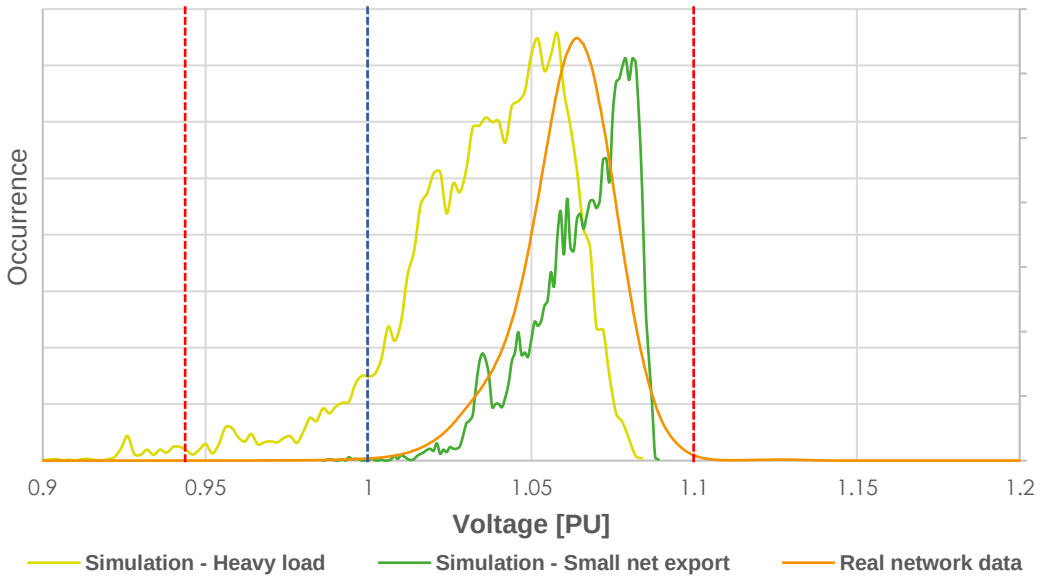
The single-phase LV voltage tolerance specification [1] is 230V +10% -6%. However, the most common supply value is around 240V [2]. This high voltage bias, a legacy from the old GB 240v +/-6% specification, allows for the significant voltage drop in the LV system which may occur at times of high load.

As we decarbonise the economy, peak loads are forecast to rise, with significant contributions from EV charging and heat pumps. This will result in increasing voltage drops along distribution feeders, especially for consumers who are towards the end of long radial feeders. Conversely, the power output from local embedded generation, including roof-top solar PV and V2G, can lead to local voltage rises.

As an example of the distribution of voltages which can be present at LV, a representative 33kV to LV network was modelled in OpenDSS including approximately 150,000 individual LV connections, based on [3]. The MV feed into the model fixed the 33kV voltage at 1 PU.

Two simulated cases are presented representing different times of day: a heavily loaded network and the same network with a small net export of power due to embedded generation. For comparison, real network data[4] shows the distribution of voltages recorded over a 6-month period for approximately 100 properties. Note, however, that these are not typical properties; they all had PV and battery storage and as a result show unusually high maximum voltages.

Domestic voltage profile seen at consumer premises



"DNOs ensure compliance with these legal limits by a deliberate and cautious approach of running the system at the top end of this range to ensure that voltage does not fall below the minimum legal level when demand surges."[5]

[1] The Electricity Safety, Quality and Continuity Regulations 2002
[2] Western Power Voltage Limits Assessment Discussion Paper
[3] Hybrid European MV-LV Models
[4] Cornwall LEM Residential Electricity Dataset with Solar Production and Battery Storage
[5] Optimising voltage across the grid | Yorkshire & Humberside Climate Commission

The full +10%, -6% voltage tolerance range is used in current distribution systems, with a potential for some infrequent voltage violations at both limits.

INTRODUCTION

Causes of wide-area voltage events

Within this WP2 analysis, our interest is in wide-area voltage events that impact a large number of consumers simultaneously. We are not concerned by local voltage events which only impact a few properties at a time, as they would not have a larger impact on grid operability.

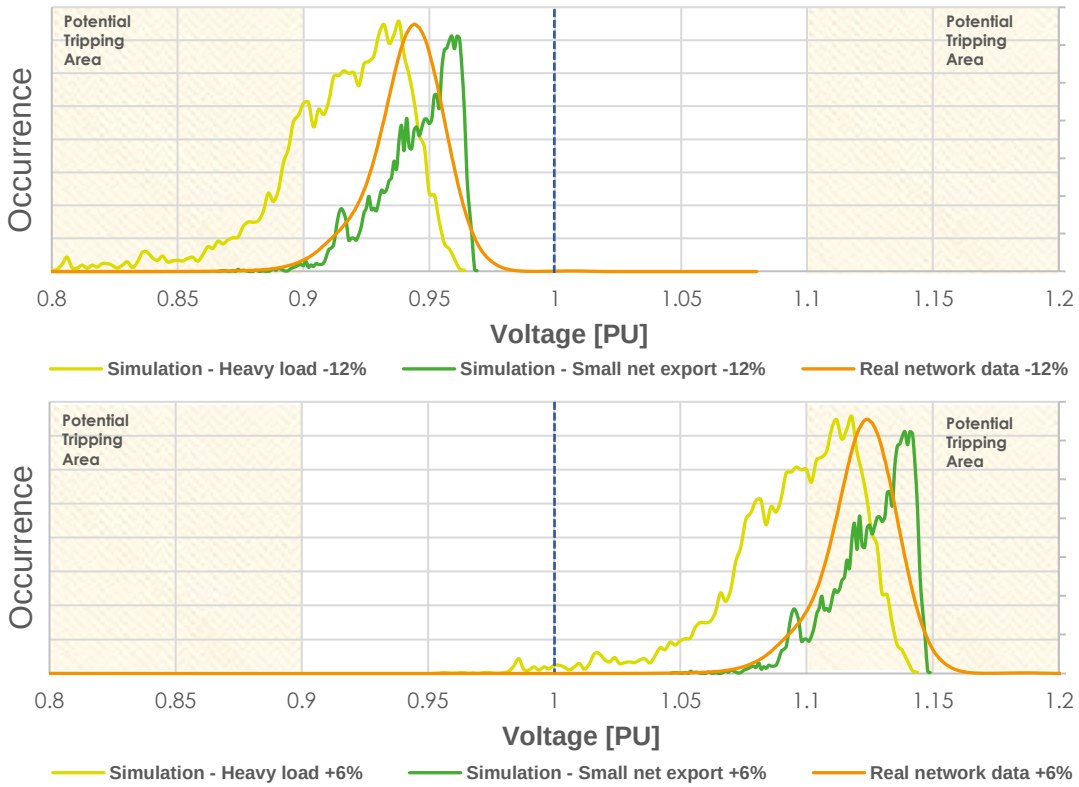
The most common transmission events giving large voltage drops are short-circuit events followed by the operation of transmission protection systems. These may occur due to a range of causes including storms and equipment failure. The grid protection systems will normally clear faults quickly[1] in <120ms. However, if the primary protection system fails to operate, an independent back-up protection will act to give a fault clearance time of no slower than 800ms in England and Wales or Offshore and 300ms in Scotland[1]. After this period, the voltage should return to levels set out in the SQSS. The SQSS permits voltage steps of up to +6% and -12% for the most severe transmission system faults, with changes of up to +/-3% for routine operations [2].

More sustained but smaller magnitude voltage variations will occur throughout the day, with variations in load and transmission system configuration. Grid operators have a number of mechanisms for adjusting voltage including reactive power dispatch from generators, switched reactive compensation and tap-changers. Larger voltage changes may be seen periodically, for example due to switching reactive compensation equipment and taking circuits in and out of service.

Changes in voltage on the HV transmission system can be reflected over relatively wide areas of LV system, and the potential impact of these changes is shown on the right. A major attenuation of the change may be seen for single-phase faults due to the impact of transformers with star-delta winding connections. A much smaller attenuation in the step change will be seen for 3-phase faults and other events, where transformers have almost no impact. This small attenuation can be due to the impact of embedded generation within the MV and LV networks.

[1] Grid code: CC.6.2.2.2.2 Fault Clearance Times
[2] Grid code: Example step offset taken from the maximum in CC.6.1.7 This is not intended to cover all possible scenarios

Example transmission voltage dip and voltage rise impacting consumer voltages.



Potential tripping area shown as +/- 0.1PU is indicative only. Actual thresholds for EVC and V2G will vary. Size of offset based on [2]

An event at transmission can impact the voltage in the distribution system for many consumers.

SPEED

The slow response time of network-level voltage control

Voltage control is becoming increasing difficult for both transmission and distribution operators.

- "Over the last decade, the regulation of voltage, by controlling reactive power, has become particularly demanding" [1]
- "Initial reviews of ED2 business plans and network models suggest that there will be a number of instances where Low Voltage (LV) networks are on a trajectory to experience both transformer thermal issues as well as non-compliant feeder voltages." [2]

Some mechanisms for voltage control within the T&D networks are relatively slow-acting. Tap-changers used for voltage control are electro-mechanical and have limited cycle life (designed for a few operations per day max). Some may have a wide tapping range, for example +10%-20%[3]. To avoid frequent operation due to hunting, techniques including dead-bands and delays are introduced. Delays can be as long as 120 seconds or more.[4]

This slow response is reflected in the statutory voltage limits and measurement techniques which are based on average values over a long time period. (ESQCR[5] no time limit defined, BS EN 50160 10 minutes) This allows voltage to be outside the statutory range 230V +10-6% for significant periods. SQSS[6] states "the target voltages at Grid Supply Points should be achieved **after** the operation of local reactive switching and auto-switching schemes, and **after** the operation of Grid Supply Transformer tap-changers." This may take a minute or more and there is no specific restriction on under- or over-voltage during this period. This issue is reflected in real life measurement data. "Monitoring of PV cluster networks over summer 2014 revealed that 29% were subject to voltage values over 253V for short periods of time over the three week monitoring period." [7]

The challenge of voltage control to consumers is being addressed by new distribution network technologies. Looking forward to the 2030s, we may find that new forms of smart voltage control will be available; see right.

Emerging voltage control technology

Independent Phase Voltage Control

IONATE's innovation is a new type of power-flow control device – the Smart Hybrid Transformer. It is a drop-in replacement for existing transformers, and capable of controlling three critically important power characteristics simultaneously.

Distribution grid voltage profiles are complex and vary constantly. Increased visibility and control will support the connection of more renewables and electric vehicles, whilst improving stability and efficiency. [8]

Use of DER for voltage control

There is an increasing interest in obtaining reactive power services for the transmission system from distributed energy resources. This involves coordination between the transmission and distribution companies, and the distributed generators. [9]

[1] Voltage Screening Report - National Grid ESO
[2] Western Power Distribution - Solving Intelligent LV - Evaluating Responsive Smart Management to Increase Total Headroom (SILVERSMITH)
[3] Code of Practice for the Economic Development of the 132kV System
[4] Code of Practice for Managing Voltages on the Distribution System Northern Power Grid
[5]] The Electricity Safety, Quality and Continuity Regulations 2002
[6] National Electricity Transmission System Security and Quality of Supply Standard
[7] Changing Standards (Statutory Voltage Limits)
[8] Smart Hybrid Transformer
[9] Use of Distributed Generation to Control Reactive Power at the Transmission Distribution Interface

It is important to know that GB grid voltage specifications are for average voltage measured over many minutes.

SPEED

The fast response time of EVC and V2G to voltage excursions

The impact of voltage events on EVs is dependent on both the duration and the size of the voltage excursion. For EV charging, both the EV OBCM and EVSE may include voltage protection, and this may be set at different thresholds with different speeds of response. There may be significant variations between products from different manufacturers.

A graph of typical under/over-voltage requirements for EVC[1][2] and V2G[3], with timescales, is shown on the right. Products are likely to evolve over the next 10 years as this market matures, so these figures may change over time. Performance requirements will change due to a combination of regulatory action and consumer feedback.

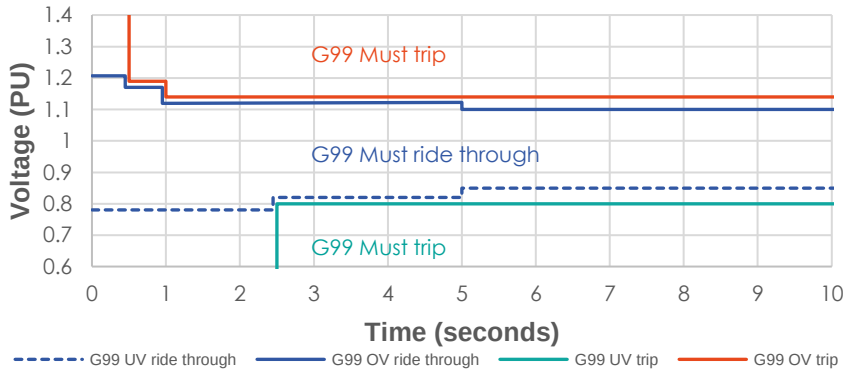
For the purposes of the analysis in this report, we considered two types of events, both with the permitted performance specified in ESQCR[4] and other power quality regulations:

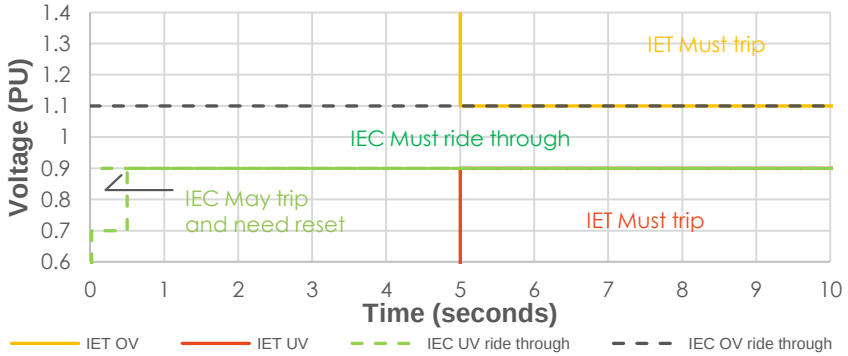
Short events ~0.05 to 0.4 sec.
This is the time it may take for network protection systems to clear a fault. In most cases HV and MV protection operation is towards the lower end of this range, but occasionally where primary protection fails the back-up protection will take significantly longer to operate. Voltage-based protection systems in EVC and V2G are unlikely to operate for voltage excursions in this timescale, however there could be issues with fault ride-through.

Sustained events 5 seconds or more.
This duration is considered as it is longer than TO and DNO protection operating times, but faster than typical tap-changer mechanisms used for network voltage control. The majority of EVC and V2G voltage-based protection systems will operate for voltage excursions in this timescale, before tap-changers act to restore voltages.

Note our terminology deliberately does not match IEEE 1159 “Recommended Practice for Monitoring Electric Power Quality” as the timescales in this analysis relate to specific time thresholds specified in under- and over- voltage regulations applicable to the GB grid.

Example ride-through characteristics V2G top, EVC bottom





[1] BS7671 18th Edition Online Training - Regulation 543.3.3.101(ii)
[2] IEC 61000-4-34:2005+A1:2009 Table 1 Class 2
[3] Engineering Recommendation G99 Issue 1 – Amendment 8
[4] The Electricity Safety, Quality and Continuity Regulations 2002

Voltage-based protection systems found in EVC, V2G and other LCT are fast responding and can be tripped by voltage excursions allowed by the SQSS.

TRIPPING RISKS

Effect of voltage excursions on EVC and V2G

Consider the impact that a significant voltage event in the transmission system could have on EVC and V2G systems. For this analysis, we take the example of a 3-phase fault at 400kV, close to our Oxfordshire office, which is cleared in 80ms protection. This type of event is relatively serious and rare for the GB grid, but it is important that security of supply is maintained.

For this analysis we will assume a ride-though performance such that about 38% of both EVC and V2G may trip for a 0.5 PU sag. This is based on small-scale analysis by Sygensys of EV-related products and a large study of the impact of real incidents on PV inverters[1]. The latter will include combined voltage dips and vector shift. Longer or deeper dips are likely to trip a higher proportion of devices. For comparison, larger grid-scale assets are required to ride through a sag of 0.7 PU lasting 0.384 seconds [3].

If at the time of this event there were 10 GW of V2G nationally, as may be anticipated at 7pm on a weekday in the mid 2030s, our analysis has shown that for this sample contingency about 250MW may trip (approximately 35,000 EVs), which may not automatically restart for 20 second or longer; some may need manual reset. **Contingences at other times or locations could have a more serious impact.**

Our modelling used OLTA and we have checked the accuracy of the approach against sample data for a real incident. This included PMUs at transmission level and a fault recorders at distribution MV level. Unfortunately, there is no readily available high sample rate time-synchronised measurement data at LV that could be used to verify voltages seen by consumers as part of post-incident analysis.

A wide range of other contingencies can cause under- or over-voltage conditions which, in some cases, can persist for several minutes. These have the potential to cause rapid loss of generation or load. A specific concern is mechanism intended for loss of neutral/PE detection BS7671:2018 Amendment 1 20202 clause 543.3.3.101(iv) [5]. This has voltage limits of <207 or >253 V for 5 seconds making EVC sensitive to voltage excursions which may be caused by other reasons, such as transmission system events.

Proportion of inverters tested that do not ride through short-duration voltage sags[1]

	Duration of Voltage sag		
Depth of voltage sag [PU]	80 ms duration	120 ms duration	220 ms duration
0.2	17%	21%	31%
0.3	31%	31%	41%
0.4	34%	31%	41%
0.5	38%	38%	52%
0.6	45%	48%	55%
0.7	48%	48%	55%
0.8	55%	55%	59%

[1] Table 5. Proportion of inverters tested that do not ride through short duration voltage sags
[2] Operational visibility of DER
[3] CP.A.3.5.1 Complete Grid Code
[4] Review of GB electricity distribution system's electricity security of supply, reliability and power quality in meeting UK industrial strategy requirements
[5] BS7671 18th Edition Online Training

Voltage excursions at transmission level may impact many devices causing loss of load or generation.

TRIPPING RISKS

Impact of wiring resistance in consumer premises on DER tripping risks

Voltage drops due to cable resistance in consumer premises can adversely impact both EVSE and V2G. A cable voltage drop can make the EVC system trip while charging due to under-voltage at the EVSE. Similarly, cable voltage drop in the reverse direction can make a V2G trip due to over-voltage.

Wiring resistance within the consumer premises can have a significant impact on voltage seen at the load point. IET wiring regulations state that the voltage drop from the origin of the installation to any load point should not exceed the following:

- Lighting 3%
- Other uses 5%

Voltage drops of this size can be a problem for loads, especially high-power loads such as 7kW EVSE which include under-voltage protection. See box right.

The issue of over-voltage tripping is well known for domestic generators such as PV installations. This is partly because, historically, DNO networks were not designed for reverse power flow from behind-the-meter generation.

At times of high PV generation, voltages on DNO networks can rise towards, and sometimes even exceed, the upper limit of the regulated supply voltage range. Over-voltage at the PV inverter can then be caused by the voltage drop from the PV system to the point of supply at the meter. As a result, system installations are recommended[1] to have cables sized such that there is a 1% maximum voltage drop on the wiring.

To minimise these risks, there is a need to install large cross-section cabling, especially where EVSE are installed at a significant distance from the meter. However, installers compete on cost and so may prefer to install lower-cost, small cross-section cable which is legal but which increases the risk of nuisance tripping.

EV tripping can occur even when voltage is within the 10-minute average specification limit

"In a single-phase installation protection is provided by a device that electrically disconnects the vehicle from the live supply conductors and protective earth in accordance with Regulation 543.3.3.101(ii) within 5 seconds if the voltage at the charging point between the line and neutral conductor is greater than 253 V rms or less than **207 V** rms"[2]

"If the maximum rated voltage drop (5%) for an installation is applied (230 x 0.05) 11.5 V can be lost. This would then lead to a voltage of 216 V – 11.5 V = **204.5V** being detected at the EVCP or at the O-PEN monitoring device where it is installed at the end of the radial circuit. If this is the case, it may therefore be prudent to design the circuit provided for the EVCP with a lower volt-drop of 1-2% to prevent this, although this would entail using conductors with an increased cross-sectional area." [3]

[1] Guide to the Installation of Photovoltaic Systems
[2] BS7671 18th Edition Online Training
[3] UK-Power-Networks-and-ECA-how-you-can-connect-electric-vehicle-charge-points

Wiring resistance in consumer premises cannot be ignored when assessing the risk of tripping.

TRIPPING RISKS

Risks associated with proposed change to -10% voltage tolerance

There are proposals to expand the GB voltage tolerance to 230+-/10% [1][2]. The change from -6% to a -10% limit helps accommodate voltage drops in distribution networks seen at high load, which are forecast with mass adoption of LCT. This change of tolerance would bring GB into line with the EU. The increased foot-room for the DNO could help reduce the need to upgrade some parts of the LV infrastructure. UK research in 2015 [3] stated "it can be concluded that UK adoption of the wider EU voltage parameters of 230V +/- 10% would most likely be indiscernible to customers." A more recent report[1] highlights "modern power electronic devices typically accepting voltage inputs of 230V +15%/-20%".

Before any change is made, there are several additional factors which the industry and regulators need to consider:-

1. Under- and over-voltage protection in domestic smart energy appliances is much more sensitive to supply voltage than most other products. Nuisance tripping is already reported at both high and low thresholds. Any change of the lower tolerance risks more frequent triggering of the under-voltage protection as noted in [2].
2. The reaction time of protection systems is typically 5 seconds or less, but the voltage specification for the DNO supply is based on a 10-minute average. This means that voltage sags and swells may trip protection systems while remaining within current regulatory limits. See right.
3. Even a small amount of tripping coincident with a voltage excursion due to serious but rare transmission contingencies is highly undesirable as EV charging and V2G becomes a 10GW+ resource. Most LV-connected DER tripping is currently invisible to DNOs and NGESO.
4. There are already almost 1 million PV systems installed that include under-voltage protection based on the current -6% tolerance with added margin. It is not practical to update the product settings along the lines of the ALoMCP.
5. The -10% limit already applies for up to 5% of the time; see right. Would -15% be allowed for 5% of the time?
6. The voltage drops caused by the resistance of wiring from the meter to the products needs to be considered in the analysis of the potential impacts of a change to -10%. This significantly impacts the risks of nuisance tripping.
7. With mass LCT it is forecast that many more supplies will be towards the lower supply limit than is currently the case.
8. Widening the lower voltage limit implies accepting higher distribution energy losses, degrading energy efficiency.
9. If voltage limits were changed to -10%, Demand Reduction by voltage reduction within OC6 [4] would be compromised[2]. This further voltage reduction, of up to 6 %, may impact operation of the some consumers equipment.

[1] Low Voltage Network Capacity Study Phase 1 Report – Qualitative Assessment of Non-Conventional Solutions
[2] Electricity Engineering Standards Review: Technical Analysis of Topic Areas
[3] Customer Voltage & Power Quality Limits 'Changing Standards'
[4] OC6 Demand Control

Grid voltage specifications are for averages

"BS EN 50160 defines the category of the monitoring device and the testing period of a ten-minute average root mean square (RMS) measured over seven consecutive days. It dictates that the parameters of the supply voltage shall be within the range of **+10/-6% during 95% of the test period** and the mean value shall be between 90% and 110% of the nominal voltage during this period." [3]

"The project team adopted a 5% exceedance rule, in line with the BS EN 50160 standard, as the basis for its selection criteria wherever possible. This document denotes this as a 'significant' exceedance. " [3]

The proposed -10% voltage limit would increase the risk of under-voltage tripping of EVC, V2G and other LCT.

TRIPPING RISKS

Mass EVC and V2G tripping risks on the GB grid

With the predicted growth of behind-the-meter DER, including V2G and EVC which are each expected to become well over 10GW capacity, the voltage ride-though performance of these resources is likely to become materially important to system security. At varying times and locations, embedded generation will be pushing voltage high and increased loads pulling voltage low. This eats into voltage margins for protection thresholds.

At present, the occurrence of voltage-based DER tripping is not very apparent. There is very little data available on the frequency of tripping of LV-connected DER resources on the GB grid. This is because, in most cases, DER will automatically reconnect after an event and so is not noticed by the consumer. There is no related SCADA data available to grid operators, and the power lost during events is rarely noticeable at national level.

Similarly, there is little data measurement available from the DER LV point of connection regarding the timescale of voltage events that could cause tripping. Most voltage monitoring is based on timescales of minutes, rather than the 0.5 to 5 second voltage protection system response times.

For example, the ENA recommends[1] setting smart meters to record extreme over- and under-voltages when >1.15PU (265V) or <0.83 PU (190V) have been recorded for a duration of **180 seconds or longer**. This is far removed from the ECV and V2G regulations. For example IET Regulation 543.3.3.101(ii) for ECV which sets thresholds 1.1PU (253V) and 0.9 PU (207V) for just **5 seconds**.

Based on the analysis in this report, with the current regulatory framework, including lack of clarity[3], there is a risk of occasional mass tripping of ECV load or V2G on voltage protection in response to a transmission system contingency. This is particularly challenging to model as data on the performance of EVC and V2G is limited and full evaluation could require some form of co-simulation of both T&D networks.

Tripping risks are associated with both low and high voltages.

"Unlike Low Voltage Ride Through (LVRT), which is a mandatory basic requirement in almost every international and national grid code, High Voltage Ride Through (HVRT) has seen comparatively less emphasis in the grid codes. HVRT requirements identify the performance of the generation asset during a voltage rise."

"For DER, overvoltage may occur in several situations, such as line-to-ground faults and fault clearance, during large-scale tripping of generation or load, or during the transient periods by switching on large capacitor banks." [2]

[1] ENA Standard Electricity Network Operator Electricity Smart Meter Configurations
[2] IRENA Grid Codes Renewable Systems 2022
[3] GC0155 Clarification of fault ride-through requirements

Fault ride-though of LV connected DER will become critical to grid operability as this sector grows to tens of GW.

DATA

Monitoring of voltage excursions

One of the key tools DNOs can use to monitor voltages at consumer premises are Smart Meters[1]. These have features designed specifically to monitor voltage excursions. However, the way in which these are used does not reflect the rapid adoption of distributed energy resources by consumers and their fast response time to under- and over-voltage.

For example, the ENA recommendation for settings of Smart Meter voltage monitoring[2] states that network switching events can cause a temporary voltage rise or fall of 6 to 10% until corrected by tap change operation in say 180 seconds. The recommended thresholds for recording extreme over-voltages are therefore <190 or >265 V for 180 seconds. The time threshold for average RMS under- and over-voltage are also equally lax, requiring the rms voltage to be <212V or >258V (2% tolerance is added to the +10-6% limit to allow for meter inaccuracy) for at least half an hour duration before it is recorded as an event.

These recommended settings are far removed from the thresholds used within voltage-based protections systems for EVC and V2G, which typically will operate for voltage excursions with a duration well under 10 seconds. The way in which Smart Meters are currently being used does not provide useful information on how voltage excursions may impact EVC, V2G and other DER which include voltage protection mechanisms. Similarly, many of the statistics presented regarding LV voltages are based on averages over a period of 10 minutes or longer.

With increased adoption of LCT which include voltage protection, this is likely to lead to increasing levels of tripping. Voltage control within the statutory limits is not sufficient to ensure reliable operation of these products. This could become a significant source of complaint for DNOs.

At a far more basic level, data for DER is very limited “Currently around 25% of generation connected to the GB system is not readily visible to the ESO.”[4] This means that significant tripping due to voltage excursions could go unnoticed, with underlying issues not being identified until there is a major loss identified via painstaking post-fault analysis. The ENA are currently working to improve visibility [6], but LV-connected resources such as the current ~4.3GW of <50kW PV[7] and future V2G are out of scope. Similarly, data on GB grid power quality and its impact on consumer devices is sparse.[5]

Grid operators have poor visibility of the operation of distributed generation.

“Great Britain has reached high penetrations of distributed generation (DG). Historically, there has been a lack of technical requirements for DG to provide system support and for network operators to monitor, control and gather detailed information on DG installations. As a result, much of it is unobservable and uncontrollable. This work has analysed the available data sources for the amount, size and type of DG installations in GB**. It is found that the lack of transparency and consistency of data are likely to act as an obstacle to the development of a more active distribution network.**” [3]

[1] Use of smart meter information for network planning and operation
[2] ENA recommendation for settings of Smart Meter voltage monitoring
[3] The growth of distributed generation and associated challenges:
[4] Operational visibility of DER
[5] Review of GB electricity distribution system's electricity security of supply, reliability and power quality in meeting UK industrial strategy requirements
[6] Operational DER Visibility and Monitoring Open Networks Cost Benefit Analysis | February 2022
[7] Solar photovoltaics deployment

DNO voltage monitoring does not normally consider DER tripping thresholds.

STATE OF THE ART

AEMO: DER voltage disturbances analysis

"AEMO has undertaken a multi-year program of work to understand the aggregate behaviour of distributed energy resources (DER) during and following power system disturbances. This allows AEMO to develop significantly more accurate models of DER behaviour, with an aim to improving how AEMO manages power system security in periods with large quantities of DER operating in the National Electricity Market (NEM) and Wholesale Electricity Market (WEM)."[1]

"Key findings on voltage behaviour

• There is considerable evidence of extensive disconnection of DPV in response to voltage disturbances. This can increase contingency sizes and impact the market through AEMO needing to take actions such as the enablement of increased frequency reserves, or implementation of more stringent network constraints.

• As a result of this finding, improved voltage ride-through behaviour is now required for new DPV inverters installed in South Australia, and will soon be required of new inverters installed Australia-wide, with publication of the new Australian Standard AS/NZS4777.2:2020. This should minimise further growth in contingency sizes associated with DPV disconnection in response to voltage disturbances.

• Despite changes to Australian Standards, a large quantity of legacy DPV with these behaviours remains installed. AEMO has developed power system models that represent this voltage disconnection behaviour, for use in examining the impacts on power system security in periods with high levels of DPV operating.

• On the basis of power system studies utilising these new models, AEMO is progressively working with network service providers (NSPs) to update power system limits and operating procedures to account for DPV and load performance in operating the power system in a secure state with high levels of DPV output"[1]

Coincident tripping for voltage disturbance may not be 'seen' by GB operators, but should not be ignored

- "There is considerable evidence of extensive disconnection of DPV in response to voltage disturbances."
- "As a result of this finding, improved voltage ride-through behaviour is now required for new DPV inverters."
- "Despite changes to Australian Standards, a large quantity of legacy DPV with these behaviours remains installed. Retrofit of these installations to improve voltage ride-through capabilities is likely to be prohibitively costly. " [1]

[1] Behaviour of distributed resources during power system disturbances

We can learn about disturbance analysis from grid operators who have a high penetration of DER.

OVER AND UNDER VOLTAGE

Recommendations

1

Recognise and actively manage the risks associated with mass coincident tripping of LCT due to under- or over-voltage as adoption increases.

2

Consider the risk to grid stability from coincident tripping of LCT as part of the assessment of the proposed voltage limit change.

3

Implement improved time resolution for grid LV monitoring so it can identify the risks of coincident tripping of fast LCT voltage protection.

ESSENTIAL ACTION DESIRABLE ACTION OPTIONAL ACTION

Bullet points from slides

- Voltage-based protection is used both on EVC and V2G to help support safe operation.
- The full +10%, -6% voltage tolerance range is used in current distribution systems, with a potential for some infrequent voltage violations at both limits.
- An event at transmission can impact the voltage in the distribution system for many consumers.
- Voltage excursions at transmission level may impact many devices causing loss of load or generation.
- Fault ride-though of LV connected DER will become critical to grid operability as this sector grows to tens of GW.
- We can learn about disturbance analysis from grid operators who have a high penetration of DER.
- It is important to know that GB grid voltage specifications are for average voltage measured over many minutes.
- DNO voltage monitoring does not normally consider DER tripping thresholds.
- Voltage-based protection systems found in EVC, V2G and other LCT are fast responding and can be tripped by voltage excursions.
- Wiring resistance in consumer premises cannot be ignored when assessing the risk of tripping.
- The proposed -10% voltage limit would increase the risk of under-voltage tripping of EVC, V2G and other LCT.

Voltage-based protection for EVC and V2G may lead to coincident tripping of significant load or generation.

CHAPTER 4

Stability Analysis and Modelling

This section investigates the impact of ECV and V2G on grid short-term voltage and frequency stability, and highlights potential opportunities for improved modelling.

CHAPTER CONTENTS

INTRODUCTION

Stability analysis and load response

In the earlier chapters we have highlighted the importance of voltage and frequency (RoCoF) control for correct operation of EVC and V2G. In this section we consider how mass adoption of EV and other LCT may impact stability due to a change in the load response to voltage variations caused by contingency events.

Analysis is presented under three headings[3]:

- **Voltage stability:** The ability of the power system to maintain or recover voltage magnitudes to acceptable levels following a contingency event;
- **Transient stability:** The ability of the power system to maintain synchronism when subjected to a contingency event;
- **Oscillatory stability:** The existence of adequate power system damping after a disturbance, with or without the application of a contingency event.

All three forms of stability must be maintained for system security. NGESO provides a Balancing Principles Statement [4] "to assist market participants in understanding our actions in achieving the efficient, economic and co-ordinated operation of the transmission system and ensuring the security of the system at all times". The section "Principles Relating to Response and Reserve Holding" states "We will calculate response and reserve holding levels based on the following criteria … (v) system characteristics such as inertia and **load response**."

In this context, "load response" refers to the natural response of load to varying frequency and voltage; it does not mean demand-side response, where loads are configured or controlled specifically to provide services to grid operators. In recent years, there has been significant focus on inertia and the impact of inverter-based generation, including attempts to measure the inertia of demand [5], but with little attention paid to load response.

Grid-following inverter-based generation has reduced grid inertia.

The "report published in 2004, primarily dealt with fairly slow, electromechanical phenomena, typically present in power systems dominated by synchronous machines and their controls. Since that time, the dynamic behavior of power systems has gradually changed due to the increasing penetration of converter interfaced generation technologies, **loads**, and transmission devices and has progressively become more dependent on (complex) fast-response power electronic devices, thus arising new stability concerns."[1]

"These inverter-based controls have thrown a curve ball at the industry"[2]

[1] Stability definitions and characterization of dynamic behavior in systems with high penetration of power electronic interfaced technologies (ieee-pes.org)
[2] Task Force report on grid stability concepts receives IEEE PES Prize Paper Award (umich.edu)
[3] Definition based loosely on Power System Stability Guidelines: AEMO
[4] Balancing Principles Statement
[5] 'Sonar of the power grid': new inertia measurement tools planned for Great Britain's electricity system
[6] Definition and classification of power system stability

Wide-scale adoption of power converter technology has a major impact on grid stability.

INTRODUCTION

Load modelling for stability analysis

Stability analysis is a key tool used for planning the development and operation of the transmission system to meet the requirements set out in the Security and Quality of Supply Standard (SQSS)[1]. The SQSS specifically requires that "voltage step change limits must be applied with **load response** taken into account." [1]

In 2010 the Fundamental SQSS Review [2] said that "A "Heavy Industrial" (P1/Q2) load response characteristic was used throughout in the absence of any better information. Voltage step-changes are sensitive to the load response and the appropriate choice of characteristics is a matter of great uncertainty." **The "Heavy Industrial" load model was defined in PLM-ST-9 [3] in 1985 and has not been updated since.**

This was the most pessimistic of the load models in PLM-ST-9 so its use represented a cautious approach, which is good for system security but is probably not cost optimal. This load model is still being used where load response is required to assess voltage step changes.

The approach of using historic load types in system modelling is typical in the industry, see right. There has been little, if any, recent investigation of load response for stability modelling related to GB grid; for example, as far as we are aware it has not been considered explicitly within the stability pathfinders[5].

Since 1985 loads have changed dramatically. Many loads are now connected via electronic power converters, rather than directly, and many of these converters include protection. This significantly changes the load response, which will not match the 'Heavy Industrial' load model.

Recent international research [4] has highlighted that "a need has emerged to develop a fundamentally new class of load models and next-generation data tools." "There is a need for high-fidelity composite load protection models for induction motor loads to better represent the aggregate dynamic behavior of distribution systems in the transmission system dynamic simulations and studies" Based on the analysis in this report, we believe similar composite models including load protection for EV and other LCT will be required for future stability studies.

Load response modelling usually takes a back seat to generation and transmission.

"Bulk power transmission system planning requires accurate models of all the major generation, transmission, and load components. Loads play an increasingly important role in power system dynamic stability and **load representation has historically been the least accurate of the three components modeled to help control a system**." [4]

[1] National Electricity Transmission System Security and Quality of Supply Standard
[2] Fundamental SQSS Review
[3] CEGB Voltage Criteria for the Design of the 400 kV and 275 kV Supergrid System (PLM-ST-9)
[4] Open-Source High-Fidelity Aggregate Composite Load Models of Emerging Load Behaviors for Large-Sale Analysis (osti.gov)
[5] Network Option Assessment (NOA) Pathfinders

Load response models used for stability modelling should be updated.

STABILITY ANALYSIS

Voltage stability analysis

Voltage stability studies are carried out by NGESO to ensure that post-fault voltage step changes are acceptable, and that voltage collapse does not occur. The present approach to these studies may prove inadequate in future. EVC demand or V2G generation could be disconnected for "secured faults" due to the sensitivity of voltage protection on EV and other LCT.

The spirit of the SQSS is that demand and generation should not be disconnected for secured fault events. For example, the definition of voltage collapse (which is unacceptable) is as follows:

"Where progressive, fast or slow voltage decrease or increase develops such that it can lead to either tripping of generating units and/or loss of demand." [1]

Protection systems for EVC and V2G typically have voltage limits based on a small tolerance beyond ESQCR[2], which is assessed using a 10-minute average measurement. However, their protection systems have response times of 5 seconds or less. A contingency event may occur while the rms voltage is already at or even just beyond the SQSS 10-minute average limit, for example after planned operational switching but before tapping occurs.

Many of the voltage control mechanisms used within the grid after a contingency event take longer than 5 seconds to respond; see right. This allows voltage to remain outside the SQSS 15-minute average limit for long enough to trigger EV protection systems.

In future, large volumes of EVC demand and V2G generation could trip as a result of voltage step changes that are currently permitted by the SQSS. NGESO and the DNOs may need to reconsider their approach to "security of supply" with the emergence of these sensitive power electronic devices. For voltage stability studies, a greater focus may be required around the 1 to 10 second time period, also known as the "Transient" or "Time Phase 1" period (see appendix.)

Post-contingency mechanisms impacting voltage recovery.

"Transient Time Phase: The time within which fault clearance or initial system switching, the transient decay and recovery, auto switching schemes, generator inter-tripping, and fast, automatic responses of controls such as generator AVR and SVC take place.... Typically 0 to 5 seconds after an initiating event." [1]

This period excludes Delayed Auto Reclose and slower voltage control actions including operation of mechanically-switched reactors and capacitors and TO and DNO tap changers.

[1] National Electricity Transmission System Security and Quality of Supply Standard
[2] The Electricity Safety, Quality and Continuity Regulations 2002
[3] CEGB Voltage Criteria for the Design of the 400 KV and 275 KV Supergrid System (PLM-ST-9)
[4] Open-Source High-Fidelity Aggregate Composite Load Models of Emerging Load Behaviors for Large-Sale Analysis (osti.gov)

The fast response of LCT protection systems needs to be considered in voltage stability analysis.

STABILITY ANALYSIS

EV frequency response, inertia and power factor

Looking to the mid 2030s, on some summer nights EVC is forecast to be up to 50% of the load on the grid. It is important that the load models used in stability studies are representative of this new type of load.

The load response of EVC and V2G is far removed from historic load types. EVC and V2G, along with many modern generators and loads, use power converters. These have many advantages as key characteristics, measured at the grid interface, can be optimized independently of the rest of the system.

This, for example, allows converter-connected loads to maintain unity power factor within a small tolerance, which is good for system efficiency. Historically, loads could have a wide range of power factors, which increased losses and made voltage control during disturbances more challenging; see right.

Similarly, converter-connected systems can often work over a wide range of frequencies with no power variation. For example, many EVC will operate from 45 to 65 Hz. This means the EVC will provide no frequency-based load relief.

Software-controlled converters can, however, tailor this response if required. For example, this would enable the implementation of the G99[2] mandatory under-frequency response for BESS, including V2G. As frequency falls below a set threshold, outside the normal control range, charging power will be reduced. If frequency falls further, they will provide power to the grid.

Alongside a naturally flat frequency response, ECV loads and V2G provide no natural inertia. In future, V2G may provide inertia if grid-forming controls are implemented.

[1] Fundamental SQSS Review: Fig C 8
[2] Engineering Recommendation G99 Issue 1 – Amendment 8

Power factor impact on immediate post-contingency voltage

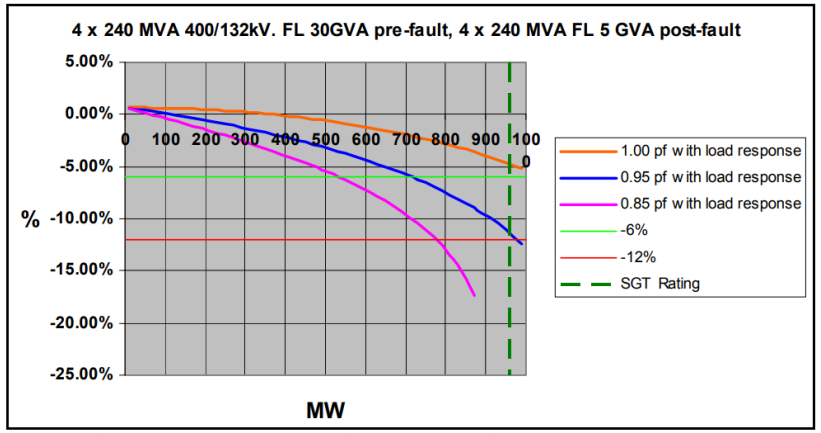


Figure C 8. Voltage step change for an outage of a double circuit only on a four-transformer 400/132kV substation resulting in a weak system post-fault.

The graph from [1] shows that the closer the load is to unity power factor, the better the voltage response is likely to be.

Unity power factor of converter-based loads may help voltage stability, but loss of frequency-based load relief and load inertia will degrade frequency stability.

STABILITY ANALYSIS

Voltage Stability

The stability of voltage supplied to consumers is important for correct operation of their equipment. Grid operators have to maintain voltage within a narrow band set by regulatory standards.

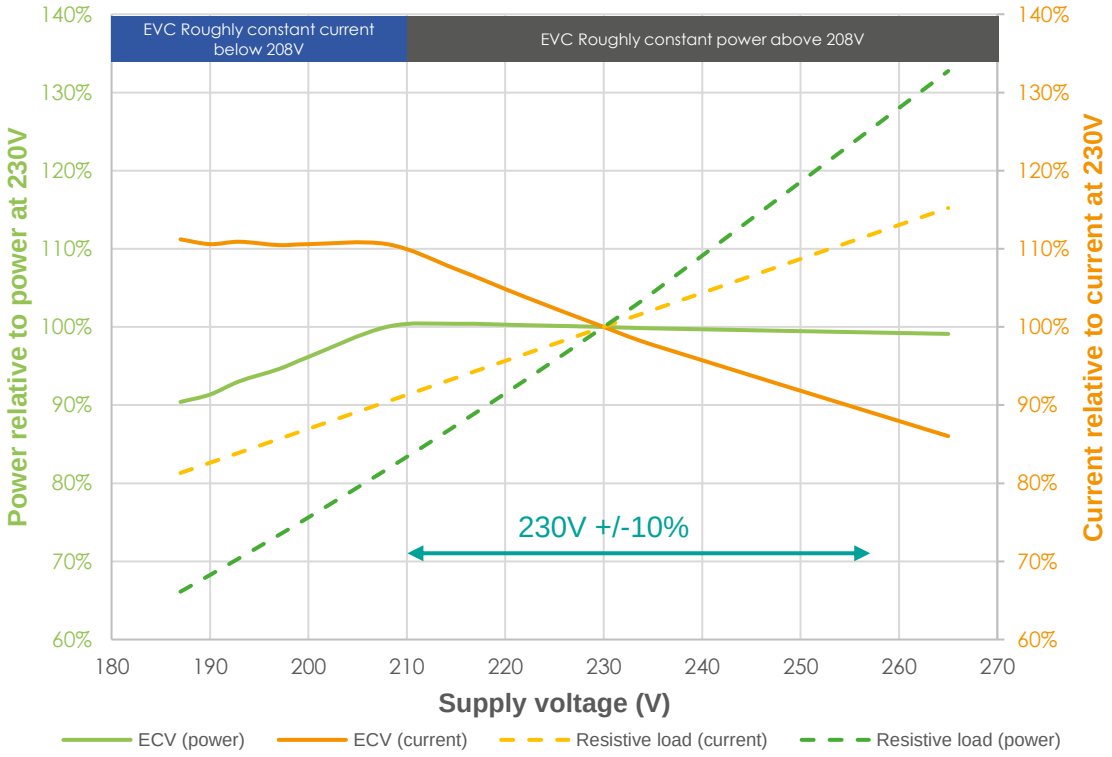
If the power taken by a load reduces with falling voltage, known as voltage load relief, this helps grid stability. In WP1 we highlighted that, when measured over the period up to 10 seconds after a change in voltage, an EVC load is generally constant power or constant current; see graph right. This represents a potential loss of load relief.

Constant power operation would appear to be a natural choice for EVC; however, some chargers may alternatively operate with a constant input current. This provides the shortest possible charging time for consumers. For domestic chargers, which are forecast to be used for approximately 70% of EV charging, the fastest possible charging is often limited due to the 32A maximum current of the Type 2 connector used on most EVs for AC charging[1].

Mass EV charging represents a major new load on the grid. The constant power / constant current nature of this load is different to the historic load types which are used within NGESO OLTA modelling. This has the potential to impact voltage stability.

For the purpose of this analysis, we have chosen to analyse the potential impact of increasing constant power load. This was chosen because constant power is the worst-case condition for voltage stability, compared to constant current.

Example EV Charger constant-power behaviour with varying supply voltage compared to a resistive load



[1] Type 2 connector - Wikipedia

EVC can present a constant-power load to the grid.

SYGENSYS

STABILITY ANALYSIS

The impact of EV load response on the voltage stability margin

Here we consider the potential effects of EVC on voltage stability in the range before the under- or over-voltage protection limits are exceeded.

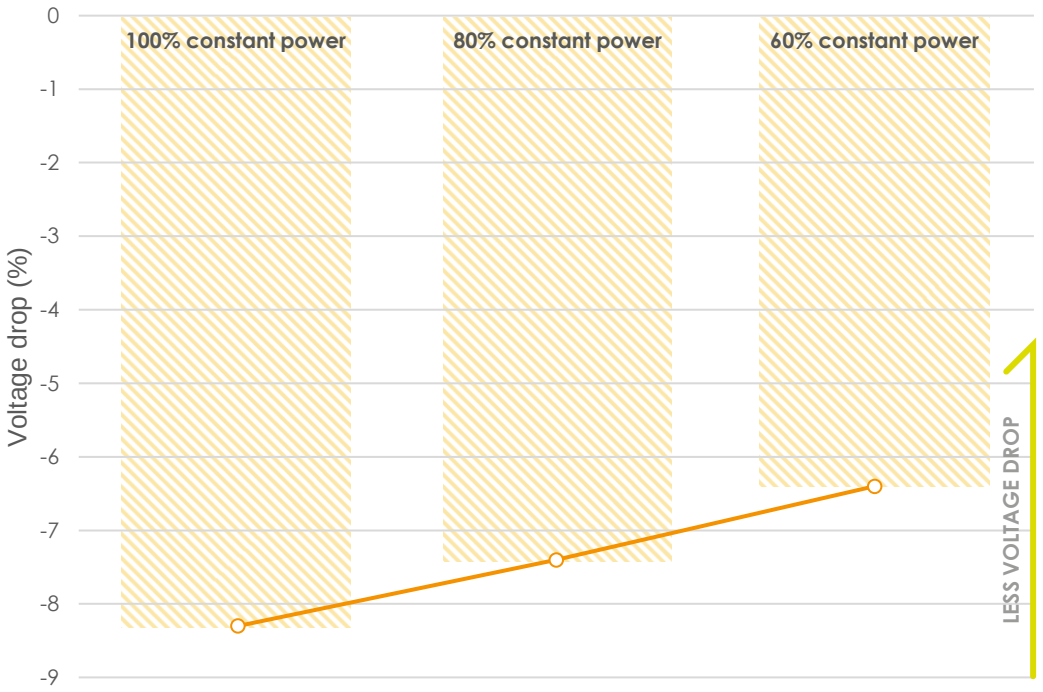
In this study we have taken an onerous voltage stability test case from the NGESO OLTA system. For the active power component of loads, we varied the proportions of constant power and constant impedance behaviour and assessed the impact on voltage drop during a specific disturbance. We are interested in the short-term impact in the seconds following the disturbance, so have considered results for the period before any tap changing.

The test cases we used varied the proportion of constant power load from 60% to 100%. This constant power load would represent not only EVs but also other loads which use electronic power converters, for example variable speed drives which will be constant power for small voltage variations (unlike directly-connected motors which will provide natural load relief).

As anticipated, the results on the graph right show that the higher the proportion of constant power load, the higher the voltage drop in the contingency study. This behaviour would make it harder to prevent LCT tripping on voltage excursions, for both positive and negative step changes in voltage.

Due to the lack of information around present-day and future load characteristics, it is not possible to quantify the increased risk from EVCs or the potential need for mitigating actions, if any. More detailed analysis of the response of EV chargers and other loads to varying voltage would be required to produce an accurate load model.

The impact of increasing constant-power load on pre-tapping voltage in a contingency study



Constant-power loads can degrade voltage stability.

STABILITY ANALYSIS

Future voltage stability modelling

With the growth of LCT, LV voltage control will become increasingly important for consumers and grid operators alike. EVC and V2G are more sensitive to voltage excursions compared to most historic devices connected to the LV network. Given that their protection functions will operate within seconds, particular consideration needs to be given to post-disturbance, pre-tapping voltages.

Key challenges for future load modelling include:

- Present-day load characteristics are not well known, and it can be difficult to predict future changes.
- The introduction of EMT studies[2] to provide more accurate modelling of converter-based generation will increase the importance of load modelling.
- The approach to load modelling must consider the compromise between accuracy and simulation time; studies need to run reasonably quickly because of the volume required to maintain secure and economic operation of the grid.
- Distribution network loads from large numbers of customers need to be accurately represented as aggregate load models, for example at Bulk Supply Points (BSPs).
- Simulation results need to be evaluated to assess how much LV-connected generation or load might trip as a result of a transmission disturbance.

These challenges should be addressed because improved modelling of loads could help with identifying new risks, evaluating potential solutions and reducing costs. For example:

- Modelling the impacts of voltage excursions on loads is important when considering the potential value of fast-responding reactive power from DER.
- The proportion of constant-power load could influence the choice between relatively slow-acting switched reactors and fast electronically-controlled SVCs[1] for post-fault voltage control.

DNOs will play a key role in reactive power management

Voltage
What is the next big operational challenge?
"There is also a need to work with DNOs to improve reactive power forecasting which would enable **more accurate modelling**, leading to improved analysis and identification of any voltage issues." [3]

"Our next big challenge is to overcome the challenges of accessing **reactive power from distribution connected assets**. As the volume of embedded generation continues to grow, accessing reactive power capability on these assets is key to managing **transmission network voltage levels**." [3]

[1] Static VAR compensator -Wikipedia
[2] TOTEM (Transmission Owner Tools for EMT Modelling) Extension
[3] Operability Strategy Report December 2021

LCT is both part of the challenge and a potential solution for voltage control.

STABILITY ANALYSIS

Potential for enhanced transient stability

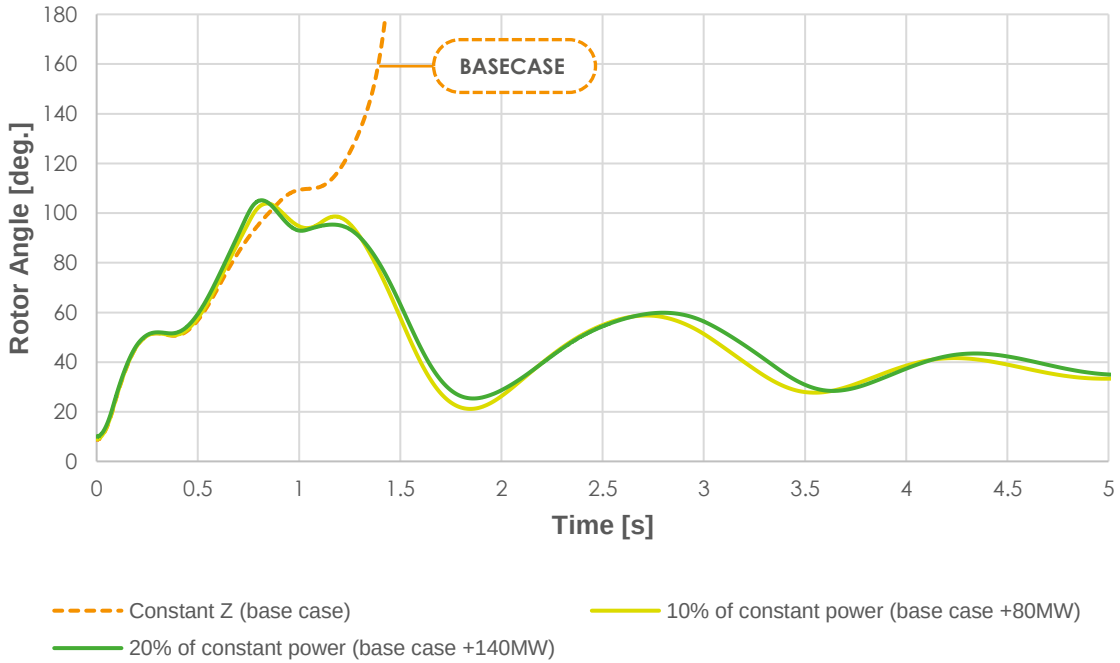
Transient stability is the ability of the power system to maintain synchronism when subjected to a fault event. During the fault, synchronous generators accelerate because electrical demand falls due to the reduced voltages whilst the mechanical power input to the generators is largely unchanged. Once the fault is cleared, it is vital that the generators decelerate and return to synchronous operation. Loss of synchronisation is called "pole-slipping" for synchronous generators.

In this study, we have taken a transient stability test case from the NGESO OLTA system which involves a double circuit fault and trip in Scotland. Our base case sets the power transfer across a transmission boundary such that the system is just unstable after fault clearance (i.e. with pole-slipping). In line with NGESO (and industry) standard practice, the base case OLTA study uses 100% constant impedance load models.

We then changed a small proportion of the load from constant impedance to constant power, to represent the potential impact of increasing EVC load. At 10% constant power, the system is stable even with an extra 80 MW power transfer over the boundary; with 20% constant power, it is stable with 140MW extra power transfer. Algorithm failure occurred for high proportions of constant power, indicating that this is a numerically challenging simulation.

Counter-intuitively, this study shows that introducing constant power load helps transient stability; compared to 100% constant impedance, a modest increase in boundary transfer was possible. The existing modelling approach with constant impedance loads may be conservative for system security and good for simulation speed, but it may slightly over-constrain system operation.

Pole slip study showing the impact of changing load response



Accurate modelling of voltage load response can improve transient stability.

STABILITY ANALYSIS

Transient stability of inverter-based resources

Currently, NGESO transient stability analysis is based only on the performance characteristics of generators modelled within the OLTA system. These will include synchronous machines and large IBRs with controller models provided by the generator operators.

The current OLTA modelling approach does not make any specific attempt to identify the risks associated with vector shift tripping of small IBRs, which may have radically different performance to the generators currently modelled. This means that existing transient stability modelling may not accurately identify the risk of loss of generation from DER due to PLL loss of synchronisation, and indeed the rms simulation method itself may not be sufficient to analyse PLL behaviour.

At some times of day, DER will be a significant proportion of total generation, and any tripping of IBRs would only be indirectly apparent to NGESO and the DNOs through its impact on frequency and net demand. “Currently around 25% of generation connected to the GB system is not readily visible to the ESO”[1]. This means the location of significant tripping could go undetected.

Small IBRs, including V2G, may have very different characteristics to synchronous machines, especially as phase step ride-through requirements for GB are currently unclear or undefined[2]. Data from AEMO, who have identified serious concerns in this area, show some IBR PLLs may become unlocked for a grid phase step as low as 15 degrees, whereas other products may successfully ride through phase jumps of up to 90 degrees or more[3].

Several V2G products on the GB market are listed on the ENA type test register[4]. The test reports, for example [5],[6] show that these comply with the +/- 50 degree requirement of “Loss of Mains Protection, Vector Shift Stability test.” However, this only applies to the protection system, so does not determine if the PLL itself remains locked and the product continues delivering power to the grid during this test. Some products may curtail power for a short period, also known as "momentary cessation", which may not be classed as disconnection but could still be a worrying coincident loss of generation. See right.

Potential V2G response to phase angle jumps

Inverter behaviour was classified as one of three types:

- Ride-through – the inverter remains connected to the grid during and after the disturbance. After the disturbance, the inverter continues to inject same amount of power as in the pre-disturbance condition.
- Power curtailment – the inverter reduces the output power in response to the disturbance but remains connected to the grid. The inverter then returns to the pre-disturbance output power (adhering to the power ramp-rate defined in the relevant standard). This category includes inverters that reduce their output power to zero yet remain connected to the grid.
- Disconnection – the inverter disconnects from the grid in response to the disturbance.

[3]

[1] Operational visibility of DER
[2] GC0155 Clarification of fault ride through
[3] Behaviour of distributed resources during power system disturbances
[4] ENA type test register
[5] Nichicon V2G compliance test report
[6] Wall Box Quasar V2G compliance test report

Current transient stability analysis may overlook some of the impact on the rapidly growing population of DER.

STABILITY ANALYSIS

Potential for enhanced oscillatory stability

This test case studies the impact of a double circuit transmission fault which is known to be close to oscillatory stability limits.

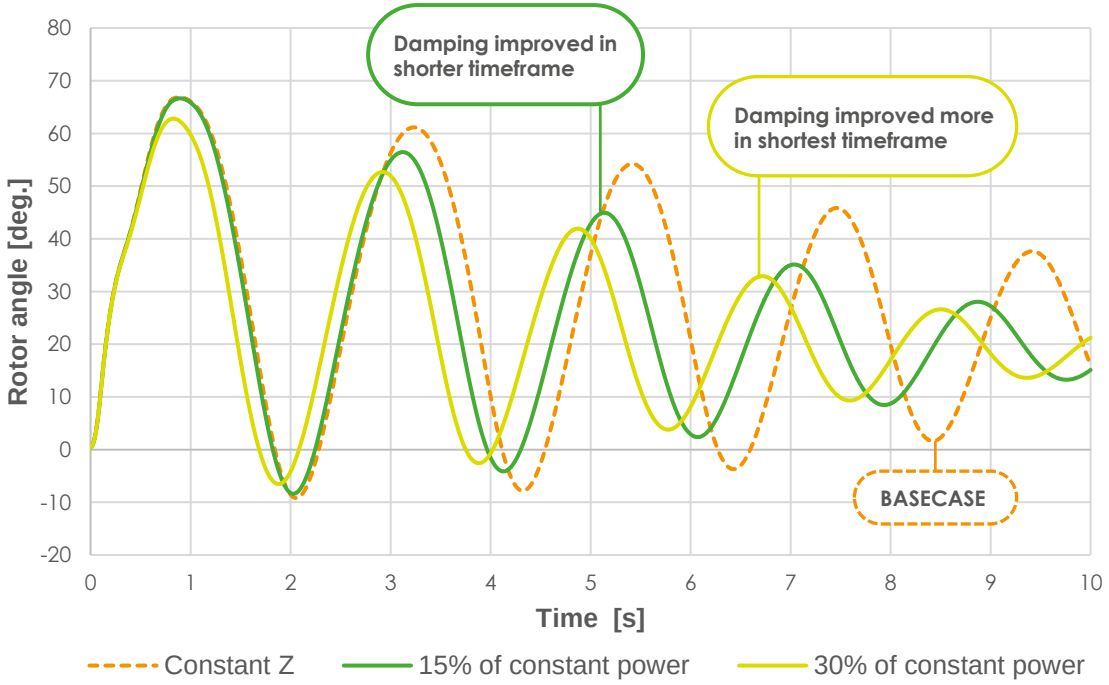
Oscillatory stability studies are normally performed by NGESO using constant impedance loads. This result is shown in the graph as the base case. It shows a marked oscillatory behaviour with a period of approximately 2 seconds. There is a slow decay of amplitude, taking about 10 seconds for the amplitude to fall by a factor of two from 80 degrees peak-to-peak (p-p) to 40 degrees p-p.

Changing a small proportion of the load to constant power significantly improves the damping of the system. As for transient stability, this was an unexpected result. If we consider the 15% constant power case, the amplitude falls by a factor of two in 6 seconds. A further reduction to about 5 seconds is seen for the 30% constant power case.

The output graph from this study shows oscillation of the rotor angle (phase), but the simulation also includes voltage effects. The change from constant impedance to constant power has no direct impact on phase, it will only have an impact at demand nodes where there is a voltage variation. This study shows that a change of load composition can have a significant impact on oscillatory behavior.

Improved modelling of loads could help improve the accuracy of oscillatory stability studies, with the potential to show increased oscillatory stability margins.

Oscillatory stability with different proportions of constant power loads



Inaccurate load response models will impact oscillatory stability analysis.

STABILITY ANALYSIS

Demand control

Another form of system stability is the capacity of system control measures to handle the condition where demand exceeds the available supply, including all reserves. Fortunately, this is an exceedingly rare situation for the GB grid. If this situation were to occur, there is a risk of rapid system collapse with voltage and/or frequency falling.

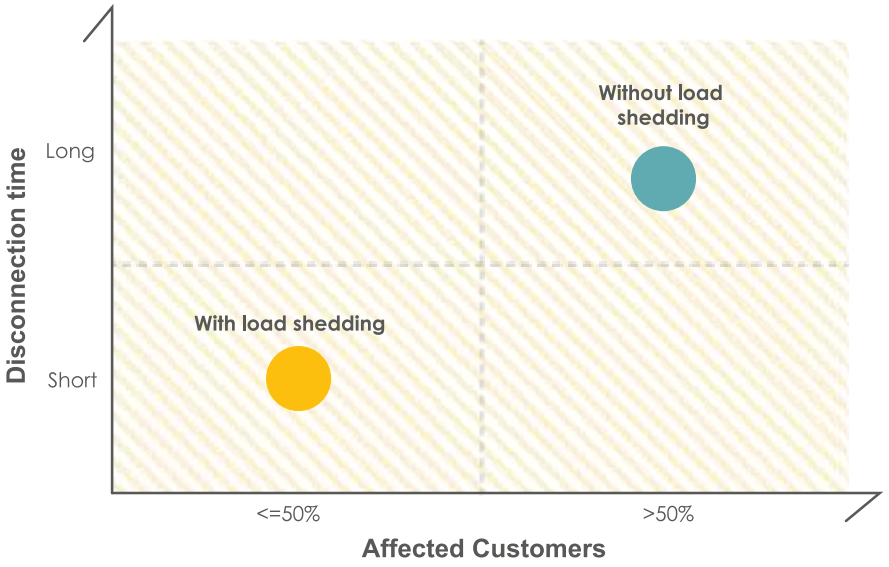
Grid Code section OC6 [1] provides two tools which can be used to prevent system collapse in this scenario; both relate to reducing demand to a level which can be supported by the available supply.

The first of these mechanisms is demand reduction by voltage reduction. If reserves fall below a critical level, for example, NGESO can instruct DNOs to reduce demand by lowering voltage. Historically, this voltage reduction has provided demand reduction due to the impact of voltage load relief, whilst having little impact on the performance of consumer equipment. With the growth of converter-based loads, both of these factors will change: loads may be constant power, so providing no voltage relief, but there may be increased tripping of loads which have under-voltage protection and are already close to low voltage limits.

The second OC6 mechanism is Low Frequency Demand Disconnection (LFDD). This operates by disconnecting parts of the distribution network when the frequency reaches specific thresholds. Historically, this just disconnected demand, but now it can also impact embedded generation, reducing its effectiveness. This is a topic of recent research[2], [3] which highlights many of the challenges. A further emerging challenge is the mandatory under-frequency response of BESS[5], which can rapidly change from importing to exporting as frequency falls, but whose output might be lost by operation of LFDD.

As far as we are aware, there has been no detailed modelling of the medium-term impact (mid 2030s) of the changing nature of loads and BESS on the effectiveness of OC6 Demand Control. This would need more representative LCT models which include elements of frequency and voltage load response, together with the protection and control systems.

Consumers may not like the prospect of demand control, but it is beneficial. [4]



The usage of under-frequency load shedding schemes leads to benefits for all customers[4] in reducing the scale and duration of a blackout.

[1] OC6 Demand control
[2] The growth of distributed generation and associated challenges: A Great Britain case study
[3] Impact of low inertia and high distributed generation on the effectiveness of under frequency load shedding schemes
[4] Fig 17 Electricity Engineering Standards Review Technical Analysis of Topic Areas
[5]] Engineering Recommendation G99 Issue 1 – Amendment 8

Current demand control techniques will need review and updating as we move to mass adoption of LCT.

STABILITY ANALYSIS

Stability during system restoration

Maintaining stability during system restoration is particularly challenging. As the system is re-energising, the island grows by adding generation, load and new network segments. During this process, it is anticipated that wider than usual voltage and frequency excursions may occur; see next slide. There is a risk that this may cause tripping of generation or loads leading to instability.

The capacity, location and status of DER is unlikely to be known accurately, which makes planning and restoration operations difficult. Some resources may reconnect as soon as power returns within specification, others may have a delayed restart or require manual intervention. In addition, the communications networks used by small DER are not likely to be resilient to loss of power. Similarly, ANM schemes which depend on DSR may not have resilient communications.

The potential benefits of V2G to resilience are often mentioned, for example[1]. They have the potential to play a major role in restoration. With the frequency response characteristics set out in [2], BESS including V2G will behave as an active form of load bank during restoration, providing frequency and voltage response. As far as we are aware, this potential contribution to restoration has not been studied in detail, and the BESS regulations were not defined with maximising benefits to restoration in mind, so some BESS responses may be far from ideal in these conditions. Further benefits to restoration could occur if V2G is equipped with grid-forming controls.

On the downside, widespread LCT adoption will give rise to a significant increase in Cold Load Pick-Up (CLPU) during restoration. The Distributed Restart project refers to a CLPU 200% above normal demand by 2030 due to loss of diversity[3]. This figure may be higher and sustained for longer periods in future with high take-up of EVs and heat pumps, especially for outages of a day or more. Addressing this issue could be important to avoid overload of DNO assets during re-energisation.

EVs could become an important flexible resource for restoration

"Because EVs are quite flexible in how they charge and contain significant reserves of fast to access energy in their batteries they are well suited to contributing to balancing supply and demand in the electricity system. **They can contribute to both the ongoing balancing of dispatched electricity with demand and in the emergency management of contingencies."** [1]

[1] The A to Z of V2G
[2] Engineering Recommendation G99 Issue 1 – Amendment 8
[3] Power engineering and trials, Assessment of power engineering aspects of Black Start from DER, Part 1 – July 2020, page 3

Large cold load pickup from LCT will hamper reenergization.

STABILITY ANALYSIS

Voltage and frequency excursions during restoration

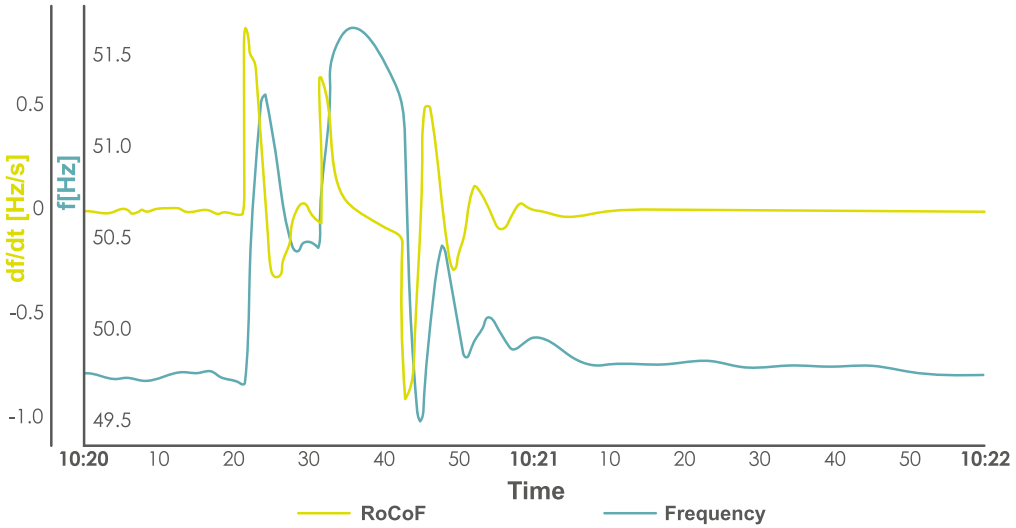
The Distributed Restart Power Engineering Trials[1] have been studying the challenges of distributed restart and have identified voltage excursions as a key issues. Simulation of the energisation of two supergrid transformers showed 11kV three-phase voltages peaked at 26.5kV (71% overvoltage*) during the energisation transient with a Total Harmonic Distortion of 78%. Whilst no load was connected during this test, this highlights the challenge of voltage control during restoration, and suggests that there is a real risk that EV chargers and heat pumps may trip during restoration, either on overvoltage or PLL "unlock" due to waveform distortion.

These high voltages formed one of the key findings from the trials: for islanded networks, "Voltage transient magnitudes and durations, generated by transformer inrush currents, were more severe on the test networks due to the low fault level (high source impedance) than would normally be experienced on an intact network with higher fault levels."[2]

The figure opposite shows frequency and RoCoF test results for the Distribution Restoration Zone Controller[3], which is designed to manage voltage and frequency in an island network during restoration. These are just simulated results, but they illustrate the very different system conditions that can be expected during restoration. The test results met the requirements of [4]; "the DRZ-C companies were requested, to design a system to operate within the frequency and voltage limits as specified within ENA Engineering Recommendation G99", but this has yet to be demonstrated in restoration trials with LV connected DER.

**The system was operating at a reduced voltage for the test to reduce the magnitude of overvoltages, so compared to the nominal voltage of 8.25kV this represents an overvoltage of 127%.*

During restoration, frequency may vary significantly and RoCoF can be high [3]



[1] Power Engineering and Trials, Demonstration of Black Start from DERs (Live Trials Report), Part 1, December 2021., page 38.
[2] see[1] page 6.
[3] DRZC Factory Acceptance Testing 1 Report by GE Digital April 2022, page 63.
[4] Power Engineering and Trials Assessment of Power Engineering – Aspects of Black Start from DER Part 2 – December 2020

Voltage and frequency control during restoration is difficult and excursions could lead to DER tripping.

MODELLING

New modelling needs

Historically, the detailed performance characteristics of behind-the-meter DER have not been regarded as materially significant in the context of full GB system stability studies. Given the forecast of rapid growth to tens of GW in the 2030s, they are likely to be significant soon.

Changes are not only limited to DER generation alone. Loads such as EVC will play an active role in balancing supply and demand and will include protection systems, which can impact system-wide performance during contingency events. This presents a serious challenge for system modellers.

Full co-simulation of the GB TO and DNO networks is not currently practicable in OLTA. The multiple millions of LV-connected DER have to be represented by aggregate models to make system simulation viable. This has typically been as a ZIP load model at a BSP and a static generator to represent aggregate embedded generation, such as wind and solar farms. Any behind-the-meter generation is simply netted off against load.

IBR have complex software control algorithms and represent a new modelling challenge alongside the long-established requirement to model controllers for synchronous machines, HVDC and other devices such as series compensation.

Ensuring power system component models are accurate representations of distribution-connected resources is difficult. Model verification and validation is often a labour-intensive and relatively manual process, so is rarely attempted. Direct testing of load response, for example, requires imposing voltage steps on consumers; this is intrusive and not risk-free, and has not been carried out in GB for model validation purposes since privatisation in 1990 (though there has been testing of load response for OC6 demand reduction[1]).

This situation is not unique to GB. However, in regions where there have been major DER contributions to incidents, there have been significant moves to enhancement DER modelling both in terms of the models [2] and the tools[3] used for modelling. Tools suppliers are responding to the emerging needs and developing tools for large-scale mixed transmission and distribution system analysis[4][5].

International examples of the need for more advanced modelling.

"AEMO has undertaken **a multi-year program of work to understand the aggregate behaviour of distributed energy resources (DER) during and following power system disturbances.** This allows AEMO to develop significantly more accurate models of DER behaviour, with an aim to improving how AEMO manages power system security in periods with large quantities of DER operating". [2]

"Electromagnetic Transient Modeling and Model Quality Checks: NERC strongly recommends that EMT modeling and studies be incorporated into NERC Reliability Standards to ensure that adequate reliability studies are conducted to ensure reliable operation of the BPS moving forward. **Existing positive sequence simulation platforms have limitations in their ability to identify possible performance issues, many of which can be identified using EMT modeling and studies.**"[3]

[1] System HILP Event Demand Disconnection (SHEDD)
[2] Behaviour of distributed resources during power system disturbances
[3] Recommendations for Industry Action- NERC 2021 California Solar PV Disturbances Report
[4] Large EMT & Phasor-domain Simulation on the cloud: OPAL-RT
[5] How to achieve 108000 nodes of mixed transmission and distribution

Load modelling from the 1980s will not be fit for purpose for the 2030s.

MODELLING

Aggregate EVC and V2G models

The forecast rate of load growth on the system combined with the change in load mix is something that has not been seen in the last 50 years. The growth of EVC, V2G and heat pumps will have a major impact on grid stability and this needs to be reflected in the models used within simulation studies.

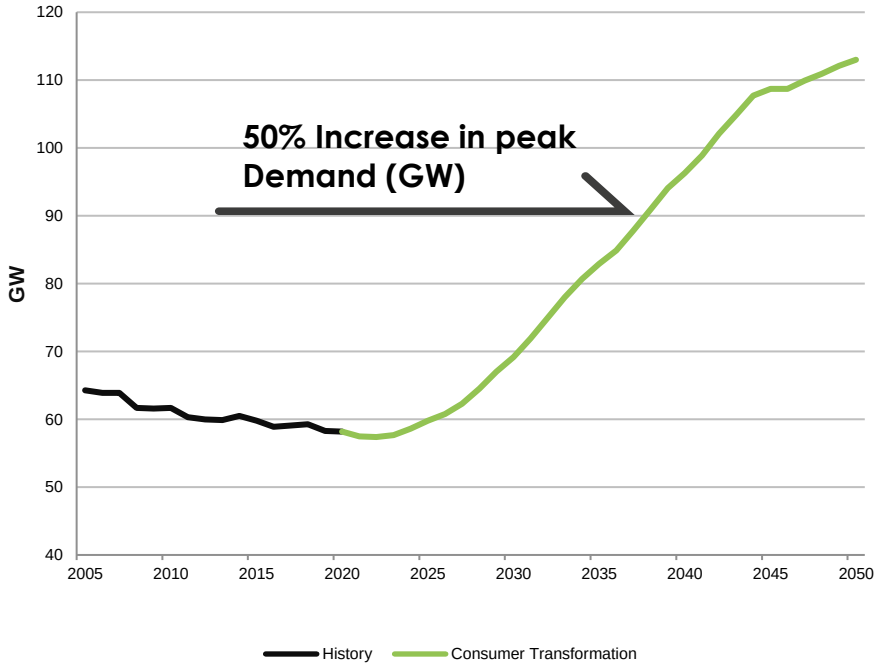
For small deviations around nominal voltage and frequency, these loads will be largely constant power with unity power factor, and provide no inertia. For larger deviations, the impact of their protection systems will be seen, which may be significant during contingencies.

Current V2G systems are grid-following and include LoM protection based on voltage limits and RoCoF. They have no variation in power for small voltage changes and provide no inertia or power system stabilizer function. For wide frequency deviations, they have mandatory under-frequency and an optional over-frequency response plus protection.

Ride-though performance will be complex, with the potential for PLL to lose synchronization on vector shift. Recovery may be delayed; V2G generation has a 20s minimum reconnection delay after it trips, but it may default to charge following reconnection and then wait for restoration of communications with an aggregator before commencing V2G. EVC-only products may limit ramp rates or turn on and off almost instantly. Future V2G systems may be more capable, including grid-forming or other complex control modes.

The combination of many millions of these device and the complexity of these characteristics, combined with features of the distribution networks such as unbalanced single-phase connections and load-dependent voltage drops, needs to be brought together into some form of aggregate model for system simulation. Models may vary depending on the needs of the study, from simplistic for basic load flow to highly complex for some contingency analysis.

Demand on the GB grid is forecast [1] to increase rapidly



[1] Future Energy Scenarios, July 2021, National Grid ESO

The complex nature of behind-the-meter devices may have an increasing impact on grid operability.

MODELLING

Electromagnetic Transient models

The increasingly dynamic nature of a low-inertia grid and the fast complex characteristics of IBRs, such as PLL response to vector shift, has exposed the limitations of phasor-based simulation tools. This is acknowledged, for example via the National Grid ESO TOTEM project[1][2] which is looking to exploit the capability of Electromagnetic Transient tools for transmission system analysis; see right.

This activity is addressing the impacts of large-scale inverter-based generation, partly in response to BEIS and Ofgem[3] concerns regarding compliance processes and modelling processes for new and modified generation connections in relation to the power outages on 9 August 2019. For large assets, this will feed through into business as usual via the GC0141 modification.

Small DER including EVC, V2G, small BESS and PV will share some of the same characteristics of larger IBR. This extends well beyond features such as voltage-based protection. For example, if as forecast on some occasions up to 25% of demand is being met by V2G, there is a significant risk of control system interaction between V2G inverters or other new forms of instability. Control system interaction would be a form of loss of temporal diversity which could cause multiple small resources to behave in the same manner at the same time, leading to significant effects at regional or even national level.

Some studies of the detailed performance characteristics of EVC and V2G systems could benefit from the use of EMT modelling, especially investigation of fast phenomena which cannot be accurately represented within phasor-based simulation. These issues may need to be studied at feeder or substation level and the results used to enhance aggregate models used for GB system-wide studies.

EMT modelling for GB transmission

TOTEM (Transmission Owner Tools for EMT Modelling)

"**Conventional phasor-based RMS simulation tools have limitations in studying weak, low inertia systems due to the level of detail that is represented.** A move to developing more detailed electromagnetic transient (EMT) based models which will address these concerns is proposed as a solution and is seen as a key way of de-risking the integration of the technologies described above." [1]

"This project is focused on the 'Development' of innovative tools and resources for power system modelling and analysis. It will produce a model that can mimic large volume power electronics and enable formulation of mitigation measures to future proof the GB network associated with the energy transition." [2]

[1] TOTEM (Transmission Owner Tools for EMT Modelling)
[2] TOTEM (Transmission Owner Tools for EMT Modelling) Extension
[3] GC0141: Compliance Processes and Modelling amendments following 9th August Power Disruption

Phasor-based rms simulations tools cannot identify all of the stability issues related to IBRs

MODELLING

Benefits of improved modelling

The ability to accurately and effectively model stability constraints is essential to efficient operation of the system as noted right.

Improved modelling of uncertainty should lead to a range of outcomes including:

- Better estimates of transfer capability leading to reduced curtailment of renewable generation.
- Improved analysis of system stability limits, reducing need for reserves.
- Enhanced ability to model complex interactions in low-inertia weak grids.
- Better understanding of the risks associated with LV-connected DER, which would require inclusion of the aggregated effects of DER connected within the distribution networks.
- Long-term planning based on forward-looking, predicted load characteristics, rather than models of historic load.
- Support for more detailed post-contingency analysis.

The challenge is to deliver these enhancements:

- With confidence regarding accuracy, which would require good load model verification and validation.
- Achieving good simulation speed to allow regular assessment of a wide range of contingencies.
- Where possible, allowing for greater automation of the study processes.
- Integration with both current rms and future EMT modelling environments.

It is expected that the returns from improved modelling would provide a significant return on the investment for improved load modelling.

Probabilistic planning for stability constraints

"Lack of automation in the assessment of stability means that the ESO has to prioritise boundary calculation due to computation time – analysis can be very time consuming and so is focussed on specific areas of the transmission network. For long term planning, power system analysis is currently carried out using deterministic approaches (e.g. selected background studies such as Winter Average Cold Spell – ACS demand or summer minimum demand). **These technical studies do not consider all the variability and uncertainty associated with future energy scenarios which could have a significant impact on stability**. In the future, this might lead to under- or over-estimated transfer capabilities and sub-optimal techno-economic solutions."
[1]

[1 Probabilistic planning for stability constraints

Investment in improved modelling has potential for a large payback.

STABILITY ANALYSIS

Recommendations

1. Develop enhanced load models to improve the accuracy of stability simulations which recognize the significant change in load relief.

2. Investigate how best to include the impact of LCT protection systems in stability studies.

3. Assess the potential impact of mass smart system controlled LCT on OC6 demand control and cold load pick-up and mitigate the risk.

4. Exploit the ways in which ECV, V2G and other LCT can enhance voltage control

ESSENTIAL ACTION DESIRABLE ACTION OPTIONAL ACTION

Bullet points from slides

- Wide scale adoption of power converter technology has a major impact on grid stability.
- Load modelling from the 1980s will not be fit for purpose for the 2030s.
- The complex nature of behind-the-meter devices may have an increasing impact on grid operability.
- Phasor-based rms simulations tools cannot identify all of the stability issues related to IBRs
- Investment in improved modelling has potential for a large payback.
- Unity power factor of converter-based loads may help voltage stability, but loss of frequency-based load relief and load inertia will degrade frequency stability.
- EVC can present a constant-power load to the grid
- Constant-power loads can degrade voltage stability.
- Current transient stability analysis may overlook some of the impact of the rapidly growing population of DER.
- Load response models used for stability modelling should be updated.
- Accurate modelling of voltage load response can improve transient stability analysis.
- Inaccurate load response models will impact oscillatory stability analysis.
- The fast response of LCT protection systems need to be considered in voltage stability analysis.
- Voltage and frequency control during restoration is difficult and excursions could lead to DER tripping.
- Current demand control techniques will need review and updating as we move to mass adoption of LCT.
- Large cold load pickup from LCT will hamper reenergization.
- LCT is both part of the challenge and a potential solution for voltage control.

Improved stability modelling has the potential to help improve system security and reduce operating costs.

CHAPTER 5

The Benefits of EV Smart Charging and V2G

This section describes the technical and financial benefits which can be achieved using smart charging and V2G

CHAPTER CONTENTS

HISTORICAL PERSPECTIVE

Demand-Side Response

Smart charging is a growing form of flexible demand. It is a key component of the Electricity Networks Strategic Framework[1] and is rightly promoted by BEIS, Ofgem, OZEV and energy companies.

Off-peak tariffs promote Demand-Side Response (DSR) by encouraging power consumption at times of low demand. This is good for consumers, as it can lower their energy costs, and good for grid operators as it can help reduce peak load.

DSR has formed a part of GB grid operations for decades. Originally, dual metering and electromechanical timing allowed for fixed off-peak timing for domestic storage heating. Later, this was enhanced by a radio timing system which provided different groups of households with different off-peak periods. This was based around the Economy 7 tariff.[2]

Technology has progressed a long way and we now have smart EV chargers allowing remote control of the charging schedule. This can include control via an aggregator dynamically adjusting charging in response to wholesale market pricing. Smart meters can then be used to support billing for agile tariffs, providing consumption data for each half-hourly settlement period to consumers and energy suppliers. They also support bidirectional metering with monitoring of energy being supplied to the grid from generators such as roof-top solar PV.

Mass adoption of EV smart charging is predicted to dramatically increase the DSR capacity, providing greater flexibility in demand for grid operators. V2G provides additional flexibility with the ability to supply power back to the grid, and even potentially to provide grid stability services such as frequency-dependent power output.

[1] Electricity Networks Strategic Framework: Enabling a secure, net zero energy system
[2] Economy 7

Radio teleswitch-controlled dual rate meter used for Economy 7

Demand-side response to pricing has brought benefits to GB grid operations for decades.

FORECASTS

Economic benefits of smart charging

The economic benefits of EV DSR and V2G have been covered in a wide range of reports. In this section of the WP2 report we highlight some of the most recent analysis and go on to explore some of the challenges in forecasting.

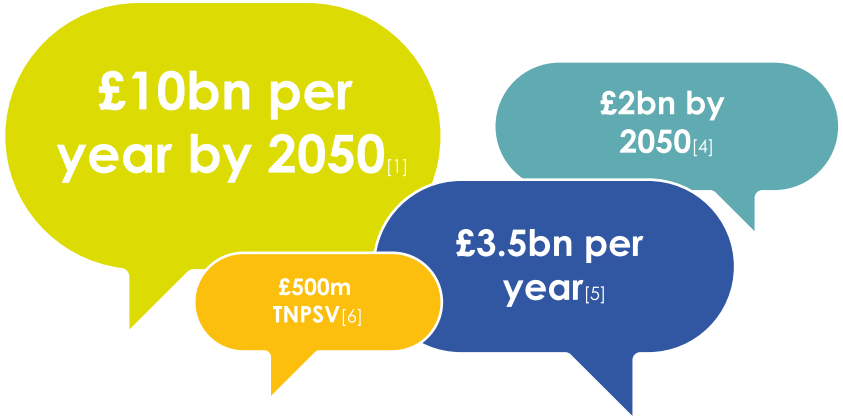
The BEIS Smart Systems and Flexibility plan[1] covers all forms of flexibility. "Better managing how and when we use energy cost reductions could be worth up to £10 billion per year by 2050."[2] It highlights that most gains from flexibility will occur after 2030, as the proportion of renewable energy generation increases and network constraints, in the form of transmission and distribution network capacity, have a greater impact. Setting the £10 billion saving into context, the Electricity Networks Strategic Framework: Enabling a secure, net zero energy system[3] states "At around £10bn annually, network charges represent approximately 20% of the typical household electricity bill."

Looking specifically at EVs, the Electric Vehicle Energy Taskforce report Charging the Future: Drivers for Success 2035[4] states "Smart charging delivers savings to the energy system worth £2bn by 2050 by cutting distribution network reinforcement costs."

A Kaluza case study [5] reports "Research has shown V2G has the potential to save £3.5bn per year in areas such as grid infrastructure reinforcement, storage and generation, as a result of the support it offers during periods of increased energy demand."

More conservatively, the impact assessment for the recent smart charging regulations [6] identified a Total Net Present Social Value of £500m. It should be noted that this assessment represents only the impact of the specific government policy to introduce mandatory requirements for smart charge points.

It is challenging to put a value on smart charging benefits separate from other flexibility services.



"Time is short and regulatory change is a slow process; we're calling on all suppliers to get ahead of that and offer true half-hourly tariffs now."[7]

"Our data predicts that a typical EV charger could earn £110 per year by stacking savings from half-hourly settlement of smart-charged EV charging electricity volumes (£66) and revenues from ongoing participation in balancing and flexibility markets (£44)."[8]

[1] Transitioning to a net zero energy system: Smart Systems and Flexibility Plan 2021
[2] Delivering a smart and secure electricity system
[3] Electricity Networks Strategic Framework: Enabling a secure, net zero energy system
[4] EV Energy Taskforce: Drivers for Success 2035 | Reports | Electric Vehicle Energy Taskforce
[5] Case study: Kaluza-enabled vehicle-to-grid (V2G) charging
[6] The Electric Vehicles (Smart Charge Points) Regulations Impact Asessment
[7] Flexitricity Outlines Wish List For 2022 As The UK Builds Momentum Towards Its Net Zero Targets
[8] FRED Flexibly-Responsive Energy Delivery
[9] Assessing the value of electric vehicle managed charging: a review of methodologies and results

Smart charging will offer considerable benefits, reducing the need for investment and operating costs.

THE TRANSITION TO NET ZERO AND AN ENERGY CRISIS

Forecasting challenges

Forecasting 10 to 30 years into the future is difficult at the best of times. As this report is being written, we are in a period of market turmoil:

- An up to ten-fold increase in the wholesale gas price from two years ago[1] with its impact on prices[2]
- New offshore wind generation has been procured at lowest-ever Contract for Difference prices [3]
- A proposal to introduce market reforms with nodal wholesale pricing.[4]

Over the next ten years, flexible demand and storage will grow rapidly. Taking the example of battery storage, FES 2022[5] predicts battery energy storage system (BESS) capacity increasing from 1.6GW in 2021 to as much as 20GW by 2030 and 35GW by 2050. Note there is already a pipeline of 27GW of grid-scale battery storage projects in the connection queue[6] and early market saturation is predicted for some services[10]. As we move towards 2050, we must also consider the potential impact of hydrogen used for energy storage.

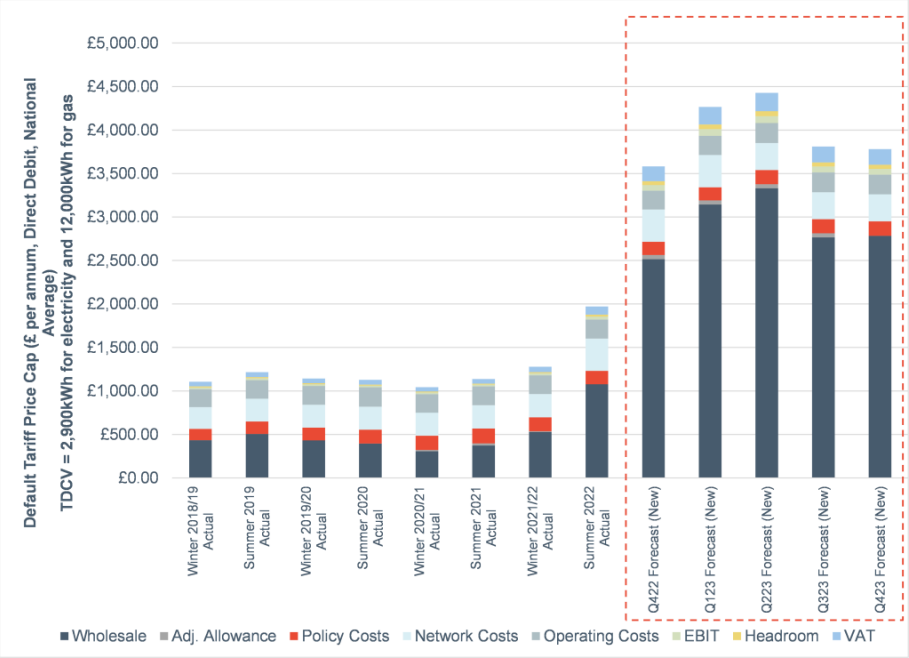
As a result of this more than ten-fold increase in BESS capacity, we anticipate that the frequency regulation and higher-value shorter-term reserve markets for ESO will be dominated by these fixed utility-scale battery storage projects, ahead of mass deployment of V2G. The fixed location and large asset size provides simplicity of control and better certainty of response for ESO.

[7] states “There are diminishing returns associated with increased availability of V2G i.e. the flexibility market is finite.” As the scale of flexible resources increases, the energy price variation through the day may decrease.

“By 2030, the UK could have almost 11 million EVs on the road. If 50% of these vehicles were V2G enabled, this would open up 22TWh of flexible EV discharging capacity per year” [8]

There is significant uncertainty over the costs of V2G hardware. V2G is currently expensive, with a £2000+ retail cost for a V2G charger, but Sygensys believes it could become a standard feature on most vehicles and may represent less than £50 added cost in the OBCM by 2030.

The impact of changes in the GB energy price cap



Source: Cornwall Insight [9] August 2022

[1] UK Natural Gas
[2] Price cap forecasts for January rise to over £4,200 as wholesale prices surge again and Ofgem revises cap methodology
[3] UK awards almost 11 aGW in biggest-ever national renewables auction | WindEurope
[4] Net Zero Market Reform
[5] Future Energy Scenarios 2022
[6] The numbers behind the record-breaking rise of the UK's battery storage market
[7] V2GB Vehicle to Grid Britain
[8] Case study: Kaluza-enabled vehicle-to-grid (V2G) charging
[9] Bidirectional Chargers Explained - V2G Vs V2H Vs V2L
[10] UK battery revenues – Timera Energy

Note: With the exception of the graph above, all figures in the report are based on market prices Winter 2021/2 or earlier.

The energy sector is in a period of long-term transition and short-term crisis, which makes forecasting difficult.

SYGENSYS

BENEFIT TO GRID OPERATORS

Time-shifting demand

A basic form of DSR is simple time-shifting of demand. Typically, this aims to move demand from the period of peak demand in the early evening to a period of lower demand, such as overnight. As previously noted, this has been happening for many years in the GB market driven by ToU tariffs such as Economy 7, which offer low rates during a fixed overnight period. A range of suppliers offer tariffs which are a variant of this general concept, and these have been widely adopted by GB EV drivers who have residential chargers, as can be seen in data sets such as[2].

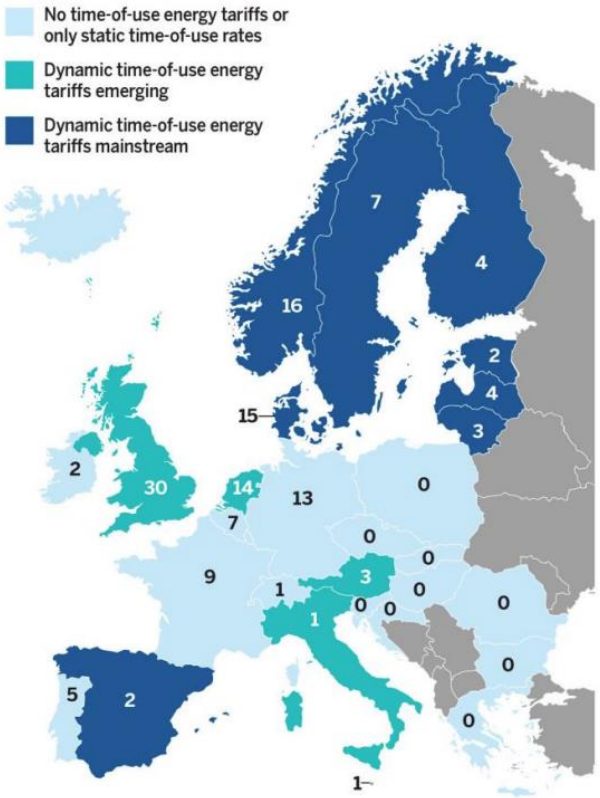
Fixed time periods and rates of this type are simple to understand and offer economic benefits to both the suppliers and the customer. However, they do not reflect the real-time wholesale market price for electricity, which will vary depending on the match between supply and demand. Recently, more dynamic tariffs have become available, where the price can vary from one half-hour settlement period to the next. These allow EV charging to respond dynamically to the market need. See right for the number of smart charging tariffs available across Europe.

Typically, demand will be shifted within a day, but given the capacity of many EV batteries and normal vehicle usage patterns, it is possible to shift some demand between days. This brings further economic benefits. Good forecasts of both energy costs and travel patterns can help optimise these systems.

It should be noted that, over the last few months, a number of the EV-specific tariffs have been withdrawn in the GB market due to financial pressures on energy suppliers caused by the large price increase for gas and the pressures this has caused within the market. To an extent this is counter-intuitive, as flexible demand from smart charging should be a benefit to suppliers. However, market structures are not currently set up to handle the extreme market volatility we are seeing.

On a longer-term basis, we are confident that smart charging is likely to become the norm for residential charging in the GB market. The FES 2022[3] forecast that up to 90% of consumers will engage with smart charging by 2035 remains credible.

Smart charging tariffs and services across Europe [1]



[1] The time is now: smart charging of electric vehicles
[2] Smart Energy Research Lab Observatory data
[3] Future Energy Scenarios 2022

Tariffs changing on the half hour do not accurately reflect underlying market dynamics.

BENEFIT TO GRID OPERATORS

V2G used for arbitrage

V2G can take smart charging to the next level, by enabling vehicles to provide power to the grid at periods of high demand and/or shortage of supply. It is being studied extensively in research and trials [1][2][3][4] but has yet to reach the stage of significant commercial deployment in GB.

A typical use case could start with a consumer driving home from work and plugging their vehicle in. As this is typically a period of high demand, the vehicle would provide power back to the grid for a few hours, helping reduce the evening peak seen by the grid operator. Later in the evening, it would charge the battery so the vehicle is ready for use by the consumer in the morning. It is predicted that this power storage can achieve a round-trip efficiency of over 90%[3], excluding T&D losses.

If there is a large enough price difference between the high-cost evening peak period and the low-cost overnight period, there can be significant financial payback for the consumer - up to £725 per year in recent trials[2]. Additional gains can be achieved for properties where there is local generation such as solar PV, by timing the sale of energy generated to maximise consumer revenue.

These benefits may be impacted by a number of potential downsides for V2G:

- Cost of the V2G charger
- Round-trip efficiency
- Impact on EV battery life
- Reliability of the V2G control systems

As technology matures, we anticipate that these concerns will fade. To realise the full benefits of V2G, however, consumers will have to choose to plug in their vehicles for most of the day, even if typically they only need a charge every four days.

"Customers in the trial have been able to earn as much as £725 a year without needing to do anything except keep their cars plugged in when they are not in use.

Research has shown V2G has the potential to save £3.5bn per year in areas such as grid infrastructure reinforcement, storage and generation, as a result of the support it offers during periods of increased energy demand." [2]

"If the average AC unit costs approximately around £100 per month to run, then V2G effectively reduces the consumer cost of AC by 50%." [3]

[1] Long-term estimates of V2G opportunities V2GB Project
[2] Case study: Kaluza-enabled vehicle-to-grid (V2G) charging
[3] Could V2G help solve the air con conundrum?
[4] Powerloop V2G trial

V2G, combined with other BESS, can play a major role in managing peaks and enhancing system resilience.

BENEFIT TO GRID OPERATORS

Constraint management

The growth of decentralised renewable generation has given rise to export constraints in a number of grid locations. These will become more extensive and will be joined by import constraints in areas with high concentrations of LCT such as EVs and heat pumps. Both transmission[1] and distribution[2] network operators are looking to use flexibility to address those constraints. This includes grid scale storage[3].

National Grid ESO highlighted "The majority of actions to reduce generation in 2020 was on wind units; £400m for constraining just over 3TWh. This is mostly from wind assets in Scotland, where we see high generation, and lower demand, hence leading to the need to export power to demand centres further south."[1]

The adoption of 'flexibility first' by a single DNO alone has projected "net benefits of up to £156 million could be delivered by avoiding traditional reinforcement costs over the course of 2023-28."[2]

Constraint management can take many forms, from a simple fixed import and/or export limitation at a site, to dynamically controlled variation in power as part of a wider Active Network Management scheme. The recently updated ENA Engineering Recommendation G100[4] includes major revisions to better support the service needs of these rapidly developing services.

Constraint management services to grid operators are likely to be provided via aggregators controlling the charging/V2G for many EVs simultaneously. The millions of EVs are predicted to be almost exclusively connected to distribution networks. This provides a benefit of being able to deliver highly localised services to meet the needs of DNOs that could not be provided by large grid-scale assets.

The DNO "has a **'flexibility first'** commitment. This means prioritising flexibility solutions where we can and only implementing network solutions where flexibility is not viable. By taking this flexibility first approach, we will reduce the need for conventional network reinforcement and endeavour to ensure that every kilowatt-hour of renewable energy is utilised." [2]

"We believe that our proposals will encourage network operators to take a more strategic approach to network planning and reinforcement. This includes **investing ahead of need where it is efficient to do so** and considering alternative approaches to reinforcement to meet the capacity needs of customers." [5]

[1] Local Constraint Market Service Design Consultation
[2] Distribution Flexibility Services Procurement Statement
[3] Storage for Constraint Management
[4] Engineering Recommendation G100 Issue 2 2022
[5] Access and Forward-Looking Charges Significant Code Review:

EVs have the potential to help manage both local DNO and TO constraints.

BENEFIT TO GRID OPERATORS

Other grid support services

EVC and V2G have the potential to provide a wide range of grid support services which could provide significant benefit to grid operators. For example, it is well known that aggregators can use EVs and other DERs to provide pre- and post-contingency services such as dynamic regulation, moderation and containment[1]. That said, the market for these services from EVs is in its infancy.

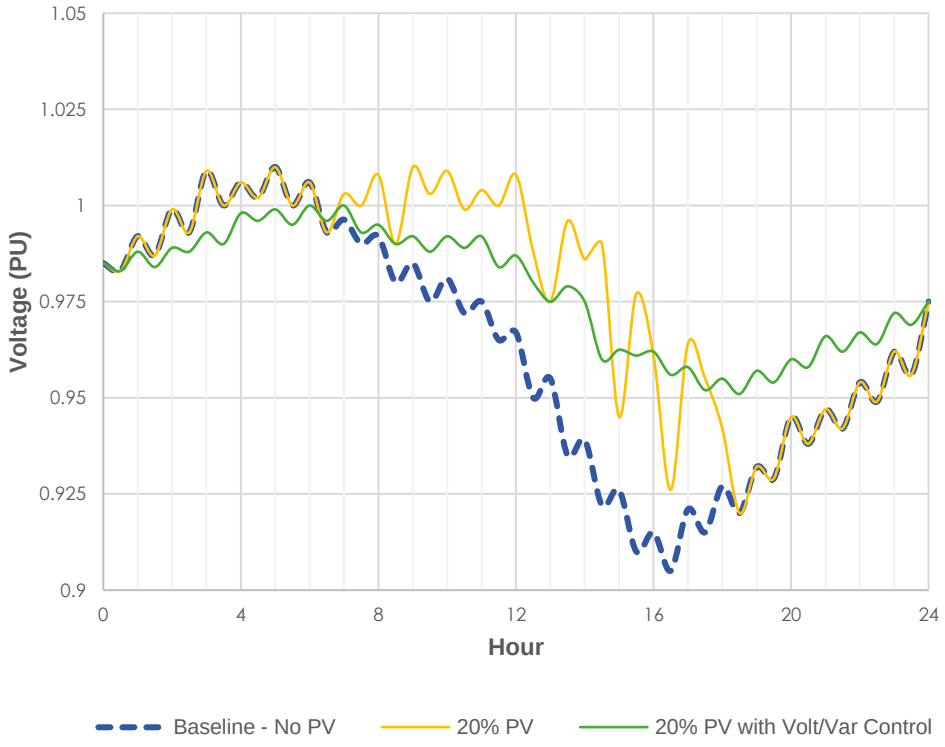
V2G, like all new BESS on the GB grid, will have to provide a mandatory[2] under-frequency response at frequency extremes that may be encountered during some unsecured faults. Mandatory requirements will naturally have push-back from some market players[3] as they are not remunerated, but preventing system collapse has benefit for all grid users.

A recent change to the GB Grid Code Minimum Specification Required for Provision of GB Grid Forming [4] states “electric vehicles which have an import and export capability (V2G - Vehicle to Grid) provide a good fit for providing Grid Forming in so far that whilst the individual contribution may be modest, the cumulative effect on the Total System could be very significant whilst providing opportunities for Aggregators and Suppliers.”

A much wider range of services can technically be provided by EVC and V2G, but current market design and/or regulation in GB does not presently support these. For example, the National Grid ESO Power Potential[5] project has investigated how DER connected to the distribution network in the area has the potential to provide both reactive and active power services to the transmission system. For an example from the USA see right . These techniques can also be extended to address harmonic control. In many cases this can be achieved entirely in software, not adding to hardware costs.

In future, these types of approaches could be exploited by GB DNOs to address the challenges to their networks coming from the mass adoption of LCT, where the LCT becomes a broad part of the solution. This may reduce the need for infrastructure investment.

Simulated voltage smoothing showing the benefit of volt-var control [6][7]



[1] National Grid ESO frequency response services
[2] Engineering Recommnendation G99 Issue 1 – Amendment 8, 12.2.3.3 (d).
[3] Flexitricity Outlines Wish List For 2022 As The UK Builds Momentum Towards Its Net Zero Targets
[4] GB Grid Forming specification GC0137
[5] Power Potential project
[6] National Grid USA EPRI: IEEE 1547 settings
[7] Impact of IEEE 1547 Standard on Smart Inverters and the Applications in Power Systems

EVC, V2G and other LCT can provide a wide range of grid support services, not just time-shifting load.

BENEFIT TO GRID OPERATORS

Summary of benefits of smart charging and V2G

In all likely scenarios, we believe smart charging will play a core role in the future GB grid market-place. Operation will eventually become largely invisible to the typical consumer, in contrast to some of the highly engaged early adopters involved in current V2G trials.

There are a clear range of benefits from smart charging, but it is difficult to forecast the value this may deliver because the market and technology is changing so quickly. For example, mass supply from grid-scale storage facilities is likely to significantly reduce the value of short-duration reserve services.

A conservative estimate of the savings from smart charging is around £400m per year by 2030, growing significantly through the 2030s. This estimate is based on a mid-range forecast from FES2022[1] of 10 million EVs and 75% participation in smart charging, combined with half the saving of £110 estimated in FRED[2] allowing for increased competition in the flexibility market. Further benefits will be achieved through the 2030s as EV numbers grow and as V2G/V2X technology, products, regulation and market design mature.

Smart charging and V2G will find a stable place alongside other flexibility services including grid-scale and home BESS. The total national storage capacity will be large enough to significantly reduce diurnal price variations, whilst the margin for intermediaries such as aggregators will be squeezed.

There is a large potential market for V2G, however its impact is dependent on a range of factors, many of which are highly specific to the market conditions, especially the trade-offs between flexibility and reinforcement ahead of predicted need. We anticipate EV smart charging will make a major long-term contribution to local constraint management. Cost savings to consumers compared to fixed-rate tariffs will remain, but will be lower than the "up to £725 per year" which has been achieved in V2G trials[2].

Critically, with robust system design and implementation, smart charging and V2G will provide a radically improved security of supply compared to a situation with completely unmanaged EV charging.

"Ofgem has a pivotal role to ensure that the costs and benefits of transitioning to a low-carbon energy system fall fairly."[4]

As we develop technology and the markets for smart charging and V2G, we must be mindful of the potential impacts on fuel poverty. We have already seen that it was the more affluent consumers who had the capital to invest in solar PV and are now reaping the benefits. There is a risk that market design may return the majority of the savings from EV smart charging and V2G to those who can afford to invest in the technology, with the risk of further increasing relative fuel poverty.

[1] Future Energy Scenarios (FES 2022)
[2] FRED Fleibly-Responseive Energy Delivery
[3] Case study: Kaluza-enabled vehicle-to-grid (V2G) charging
[4] Stepping up to the net zero challenge: Ofgem

Robust system design is a key element to unlocking the major savings to be gained from smart control of EVC and V2G.

BARRIERS TO REALISING THE FULL BENEFITS

Current Time-of-Use tariff load steps and management

As noted in WP1, the current GB market is based on a half-hourly settlement period. This helps support variable rate Time-of-Use tariffs but also produces a risk of large numbers of EVs changing their charging or V2G state at the same time, producing a large load step. Corresponding frequency steps can already be seen regularly in the GB grid frequency on the half hour. These load steps need to be managed with fast-responding generation resources dispatched to match demand, which will add to system balancing costs.

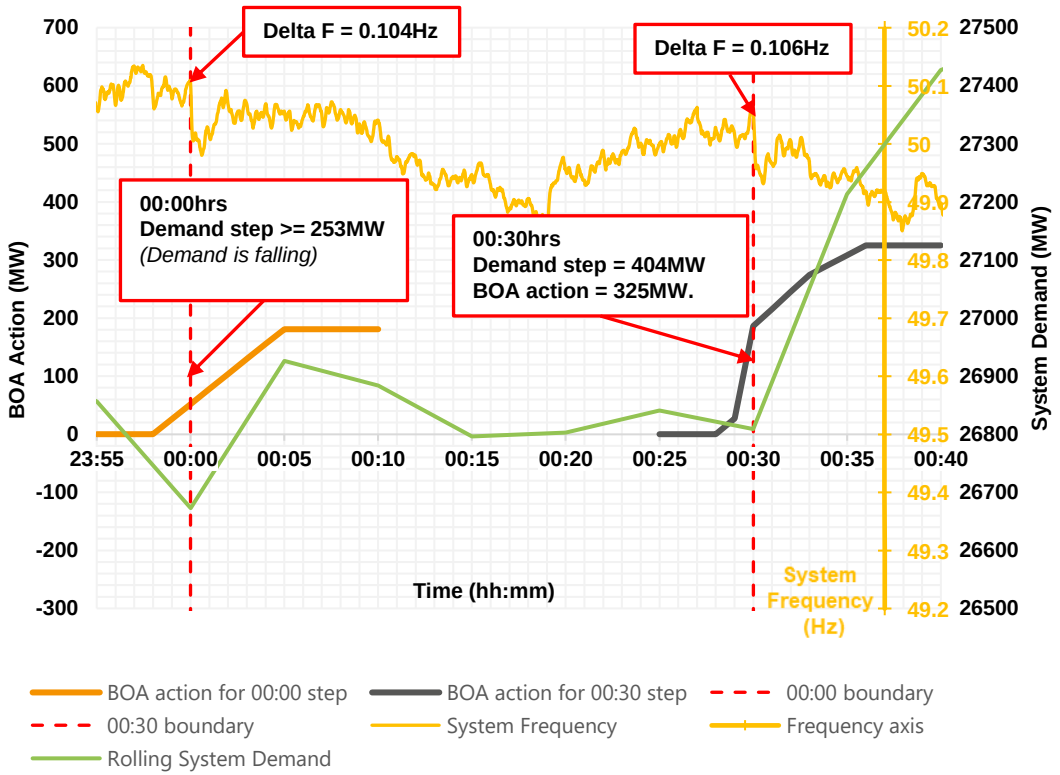
The graph right shows an example of cumulative BOA actions on the two hour boundaries, together with the 5-minute system demand taken from the BMRS website[1]. Note that there is considerable BOA activity across the whole period, but the BOAs selected for this graph are the only ones that appear to have been issued specifically to manage load steps on the half-hour boundaries. These were identified on the basis that their start and end times were close to the boundaries.

Managing these steps can be expensive. It was noted that “historically the first half hour of the day was the most expensive half hour in the day due to rate of rise in demand from Economy 7 at 00:30am”[2]. This issue has to be addressed to realise the full economic benefits of smart charging.

The steps currently seen will not be solely due to EVC, however with the rapid growth of EVC and popularity of EV-specific tariffs, EVC load steps will grow. Random delay introduced in the smart charge point regulations[3] will help spread the step to produce a ramp over minutes, alleviating some of the pressures. Forecasting of load steps and ramps would help both with short term operations and longer term market design and planning.

[1] Balancing Mechanism Reporting Service
[2] paraphrased from Project REV WP1 webinar Q&A
[3] Regulations: electric vehicle smart charge points

Cumulative BOA actions & 5-minute System Demand around Half-Hour Boundaries at 00:00 and 00:30 on 18/3/2022



Large load steps and ramps around settlement period boundaries are a challenge for grid operators.

SYGENSYS

REALISING THE BENEFITS

Recommendations

1

Investigate the potential growth of load steps on the **half-hourly settlement period boundaries** and mechanisms to predict, manage and mitigate the associated risks.

2

Address issues with the resilience of DSR, recognizing its potential impact in enhancing or degrading the resilience of critical national infrastructure.

3

Maximize the value from smart charging and V2G by using these assets to provide grid support services, not just time-shifting of energy

ESSENTIAL ACTION DESIRABLE ACTION OPTIONAL ACTION

Bullet points from slides

- Demand-side response to pricing has brought benefits to GB grid operations for decades.
- Smart charging will offer considerable benefits, reducing the need for investment and operating costs.
- The energy sector is in a period of long-term transition and short-term crisis, which makes forecasting difficult.
- Tariffs changing on the half hour do not accurately reflect underlying market dynamics.
- V2G, combined with other BESS, can play a major role in managing peaks and enhancing system resilience.
- EVs have the potential to help manage both local DNO and TO constraints.
- EVC, V2G and other LCT can provide a wide range of grid support services, not just time shifting load.
- Robust system design is a key element to unlocking the major savings to be gained from smart control of EVC and V2G.

Smart charging benefits are likely to reach £400m per year by 2030.

CHAPTER 6
Summary

This section is a summary of the report and includes an update on the impact of Project REV WP1.

CHAPTER CONTENTS

WORK PACKAGE 1

Impact from Project REV to date

Project REV has identified the potential impacts of Electric Vehicle charging on grid short-term frequency and voltage stability, and cascade fault prevention and recovery. In WP1 we detailed a significant number of risks which were not widely recognised within the industry. As a result of sharing these findings, Project REV is already having an impact on risk management processes related to EV and DSR.

The report[1] and webinar[2] have been seen by hundreds of individuals and have raised awareness of risks within the industry, both in the UK and internationally and across a wide range of stakeholders from grid operators to regulators and charge-point manufacturers.

Based on the experience gained within the project, inputs have been provided to regulatory processes including:

NGESO Grid Code[3]

- GC0154: Incorporation of interconnector ramping requirements into the Grid Code as per SOGL Article 119 – Similarity of the impact of herding of interconnectors on a settlement boundary and future scenarios with mass EVC and V2G.
- GC0155: Clarification of Fault Ride Through Technical Requirements – Importance of defining over-voltage and vector shift ride-through requirements.
- GC0156: Facilitating the Implementation of the Electricity System Restoration Standard – Explaining the potential impact of DER and DSR on the restoration process.

ENA: Proposal for topics to be addressed in future updates to ENA G99.

BEIS: Project REV is cited in the current BEIS consultation "Delivering a smart and secure electricity system"[4] and the project team plan to respond to the consultation.

The challenge for all in the industry, including regulators, is to keep pace with the rapid rate of change. Slow regulatory processes may inhibit innovation while under-regulation may lead to a large underperforming installed base of equipment which will add to grid operational costs long term, as retrospective change and product update may be virtually impossible. Over-regulation will add to costs and risk stifling innovation.

Proactive regulation is vital to facilitate innovation

"Innovation plays an important role in the transition towards a more sustainable energy system. The law is often thought of as an inhibiting factor for innovation. However, legal provisions may also serve to promote innovation. Laws which stipulate favourable conditions for renewable energy sources are an obvious example. Finally, **existing laws will often not be suited to accommodate a new technology or business model, and the legislator may be slow in reacting to these new challenges. This increases the importance of government agencies as well as non-state governance."** [5]

[1] WP1 report avaiable via ENA portal
[2] Project REV WP1 webinar
[3] Grid Code Modifications

[4] Delivering a smart and secure electricity system: the interoperability and cyber security of energy smart appliances and remote load control
[5] Governance of Energy Innovations

Increasing awareness of the way in which EVC and V2G can impact grid stability is a key objective of this project.

WORK PACKAGE 1

Underlying factors

Common-mode behaviour reducing load diversity.

The 2021 Future Energy Scenarios[1] envisage between 12 and 26 million EVs in service in 2035. With typical 7kW domestic chargers, just 2% of these chargers switching on at the same time would generate a load step of between 1.7 and 3.6 GW, significantly more severe than the August 2019 loss of supply incident[2].

Smart charging control systems could cause such synchronised action by responding to Time-of-Use tariffs, by accident or through malicious intent.

Randomisation helps soften load steps, but the volume of price-driven demand could still result in rapid multi-GW ramps.

Design for customer needs, not grid requirements.

The focus of EVC/V2G technology design is customer needs and cost; it will do “just enough” to meet grid-related regulations such as fault ride-through and high/low voltage withstand. Present regulations were not designed for a zero-carbon future so will need revision.

Charging speed is maximised by constant power / current operation, with no load response to voltage or frequency excursions. This may negatively impact system stability.

Dependence on an interconnected software ecosystem.

Smart charging depends on multiple software systems running on multiple hardware platforms from multiple vendors connected by multiple communication systems.

This complexity creates the risk of conflicting controls and unforeseen behaviour under normal and abnormal conditions (loss of comms or restoration after loss of power), and a high risk of cyber compromise.

An urgent decarbonization agenda.

It is vital that regulations are updated quickly to manage these risks while giving the industry time for implementation so that we avoid the need for a significant retrospective program (such as ALoMCP[3]);

NGESO should consider whether ToU tariffs, in the present half-hour market, will be viable when up to half of system demand is price-responsive.

Exploiting the full capability of smart EV charging Demand Side Response (DSR) flexibility and V2G can support decarbonization targets, reducing operating costs and enhancing system resilience.

[1] Future Energy Scenarios, July 2021
[2] 9 August 2019 power outage report - Ofgem
[3] Accelerated Loss of Mains Change Program

Be aware that this WP2 report does not repeat all of the topics raised in the WP1 report.

WORK PACKAGE 2

Key findings

WP2 has explored a range of issues identified in WP1 both by analysis and simulation studies. Major topics are covered are the next page, which is based on the Executive Summary at the start of this report. More specific technical points from each chapter of this report are given below:

RoCoF and vector shift

- RoCoF should not be considered a national parameter, there can be significant regional variation.
- Existing GB regulations currently lack any requirement for vector shift ride-through.

Stability studies and modelling

- Load models using for stability studies are outdated and would benefit from being updated.
- Improved stability modelling has the potential to help maintain reliability, increase capacity and reduce costs.
- Cold load pickup for smart systems and mass LCT need to be considered.

Under and over voltage

- Like DERs, converter-connected loads have under- and over-voltage protection which can lead to coincident tripping on voltage excursions.
- Existing voltage control requirements do not align with the speed of response of protection systems, and the proposed tolerance change could make tripping more likely.

The benefits of EV smart charging and V2G

- The half-hourly settlement and related tariffs help drive flexibility, but the related load steps are undesirable.
- Demand-side response control systems need to be resilient to maximise value to the system.
- A conservative estimate of the savings from smart charging is around £400m per year by 2030, growing significantly through the 2030s.

Significant cost savings can be achieved though successful deployment of smart EVC and V2G.

The capacity of EVs and domestic heat pumps on the system could exceed 100GW by 2030, eventually reaching over 300GW.
[FES 2022 data with average 7kW rating]

Capability requirements

Enhanced capabilities for ESO/DSOs:

Planning will require:
- Additional modelling data (e.g. indicative device numbers, types, locations and characteristics)
- New types of analysis (e.g. combined T&D modelling to study voltage tripping risk, EMT modelling to study fault ride-through risks)

Operations will require:
- Additional modelling data
- Additional real-time data
- Updated demand control capabilities (constant-power loads affect voltage reduction, V2G affects Low Frequency Demand Disconnection)
- Resilience against loss of smart network management services delivered via the digital domain

Forecasting, scheduling & dispatch processes will need to adapt to deliver energy over variable periods of time at lowest carbon footprint, rather than power at lowest cost

Restoration capability will need to cope with:
- Erratic behaviour of smart loads (haphazard recovery of digital systems)
- Unavailability of smart network management systems
- Huge increase in size & duration of cold load pickup

Post-event analysis will need:
- Sufficient recorded data to diagnose events involving large numbers of domestic devices;
- Modelling data to simulate device behaviour

Promote industry awareness

Raise awareness across all participants of the new challenges and opportunities from LCT.

Develop data processes

Collaborate with industry parties to define the data required from LCT devices to support effective system planning, operation and post-event analysis. Design and implement processes and systems to provide this data.

Develop modelling capabilities

Develop analysis techniques to capture the impact of transmission events on consumer LCT devices, including their fast-acting control and protection that may require EMT analysis.

Develop operational capabilities

Develop new / enhanced capabilities as follows:
- forecasting, scheduling and dispatch processes to meet LCT energy requirements over various time windows from renewable generation;
- risk assessment capability for "digital contingencies";
- OC6 demand control capabilities that are effective with high levels of constant-power loads and V2G.

Develop restoration simulation capabilities

Build a simulation capability that can analyse the following effects under restoration conditions:
- Cold Load Pick-Up with high levels of LCT;
- the likelihood of LCT protection tripping;
- the impact of different recovery behaviours for smart systems.

Develop new control capabilities where needed.

Develop regulatory framework for power domain

Develop regulations for LCT to support secure operation during normal and restoration conditions, including:
- fault ride-through capabilities;
- steady-state voltage withstand;
- smooth mandatory frequency response;
- avoiding hard-coded time periods;
- emergency control action when needed.

Reform market design

Ensure that market design enables demand to be smoothly controlled to align with renewables availability, whilst meeting LCT energy requirements over various time windows with minimum carbon footprint.

Update security standards

Consider how SQSS might be extended to cover emerging risks such as:
- "digital contingencies" (e.g. failure of ISP or aggregator IT system);
- "distributed" loss of demand or generation; multiple tripping of consumer devices due to power system events, without actual disconnection.

Develop regulatory framework for digital domain

Develop requirements for participant IT system resilience and cyber security, taking account of third-party dependencies.

Smart charging benefits likely to reach £400m pa by 2030

Operational risks

Steps, ramps or oscillations in power transfer could arise from the following sources:

Power system events
- Fault ride-through failure including vector shift
- Voltage or RoCoF protection tripping.

These could be especially problematic during restoration.

Market design & operation
- Real or accidental Time of Use price steps
- Market granularity insufficient to manage scale of LCT demands

Digital domain complexity
- Unforeseen interactions between systems
- Unanticipated behaviour of the control hierarchy (potentially loss of DSR)
- Vulnerability to failure or maloperation of eco-system components (eg ANM, aggregator or OEM systems) and infrastructure (eg ISP)
- Extensive cyber attack surface

Regulations
- Tendency to lag behind technology
- Hard-coded "economy" periods
- Loosely-defined frequency response requirements
- Network services potentially bypassing randomisation
- Randomisation only a "stop-gap"

Consumer behaviour
- Over-riding randomisation or other smart control features
- "Panic charging" ahead of real or perceived risks to supply
- "Greedy charging" during restoration

Multi-faceted risks will require a wide range of prevention and mitigation actions.

EMERGING RISKS FROM THE GROWTH IN LOW-CARBON TECHNOLOGIES

Conclusions

The pace of EV adoption over the next 10 years will contribute to an **unprecedented rate of growth in electricity grid load.**

Smart charging systems will soon control over 10 GW of load and V2G. This introduces new power and digital domain risks to electricity grid stability.

We need to address the risks urgently before they impact the security and quality of supply and to avoid the need for expensive retrospective updates.

Cost savings of over £400m per year can be achieved though successful deployment of smart EVC and V2G.

NEXT STEPS

Success through collaboration

Sygensys would like to thank to all those who have contributed to Project REV and especially National Grid ESO for the opportunity to undertake this project.

Due to their wide-ranging inputs from the contributors, Project REV has identified a significant number of issues ahead of problems being seen by grid operators. Many of these need to be resolved ahead of the mass adoption of smart EVC and V2G. This report highlights some areas where actions are already underway, but for the remainder, a broad range of stakeholders will need to be involved in the process of developing appropriate solutions.

We would encourage all innovative organisations to actively collaborate in the process. Together we can help deliver a effective resilient net zero power and transport system for 2050 and realise the substantial cost savings that can be achieved from the flexibility services EV technology can provide.

"Electric vehicles will revolutionise the way we use energy and provide consumers with new opportunities, through smart products, to engage in the energy market to keep their costs as low as possible.

Our electric vehicle priorities not only provide a way to meet our climate change targets but importantly offers ways to protect consumers from rising bills, through a three-prong approach of increased use of electric vehicles, smart charging and vehicle-to-grid technology which together can help drive down costs for all GB bill payers."

Neil Kenward, Ofgem's Director of Strategy and Decarbonisation

We would welcome feedback on the findings in this report, from NGESO as well as from participants in the EV charging supply chain including vehicle and charge point designers and manufacturers, operators, aggregators, DNOs, regulators and consumer groups both in UK and internationally.

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Urgent action is needed on regulation, modelling, system & market design to reduce risks and benefit from EVC and V2G as we move to NetZero2050.

CHAPTER 7

Appendix

CHAPTER CONTENTS

APPENDIX

Feedback on WP1

Project REV Work Package 1 was completed in February 2022. Since then, the feedback has been overwhelmingly positive. It is clearly raising the awareness of the risks of mass adoption of EVC and V2G to security of supply and has been influencing key decision makers. Two questions have been asked repeatedly:-

Why haven't these problems been seen already in markets with high EV penetration such as Norway?

This has been addressed by Norwegian grid operator NVE who highlighted[1][2] the fact that their system is already designed for high consumer demand due to wide-scale electrification of heating, so EV charging is a relatively small additional load. See graph. In addition, their generation is dispatchable renewables with over 90% of power coming from hydro which provides high inertia. By contrast, GB demand is low and EVC represents a significantly larger increase in load; the GB grid also has lower inertia.

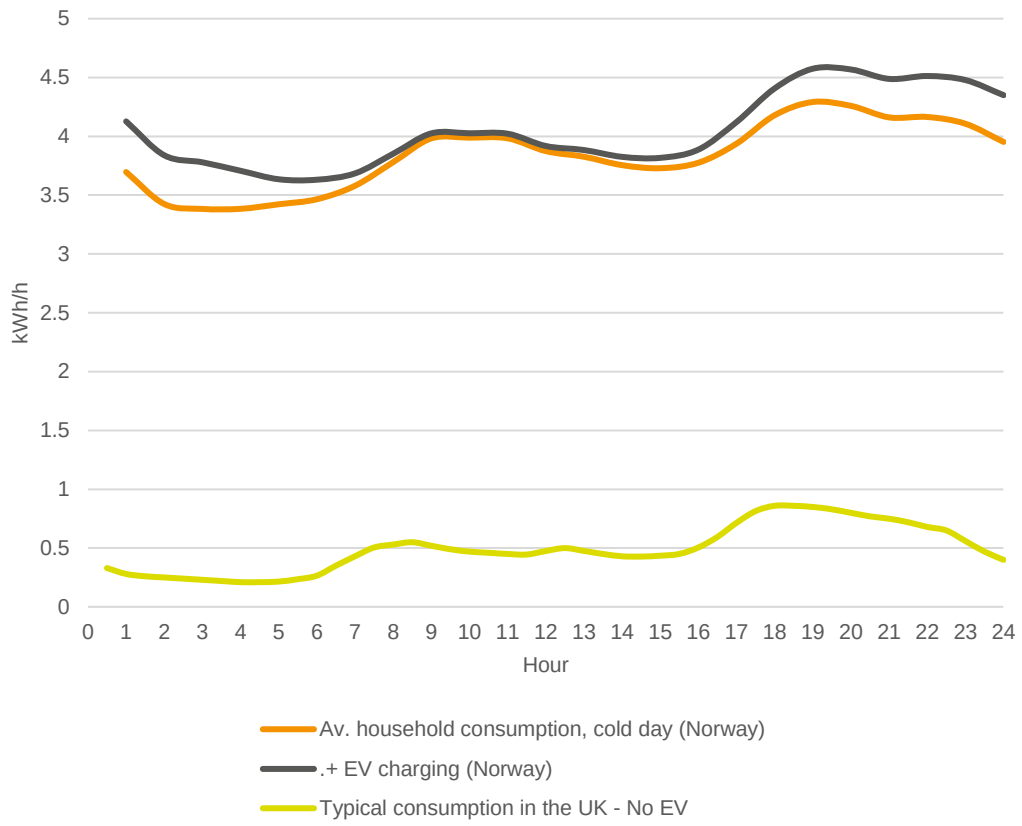
WP1 may have been catastrophising, exaggerating the potential risks?

If there were no mitigation of the issues identified in WP1 for 10 years, some of them would have a serious impact on grid operability and costs. The aim of the report was to highlight problems in an accessible way to a broad range of stakeholders so that appropriate mitigations can be developed and catastrophic power outages can be avoided.

The key message from WP1 was not to wait until the problems bite and expensive retrospective actions are needed; that would not be good for industry or consumers. We need to keep checking assumptions because the whole system is evolving rapidly, and we need to be aware of the wide range of potential risks and regional differences.

[1] Managing grid integration of electric vehicles - Event – IEA
[2] EVs in Norway: Impact on the grid, and how to deal with it
[3] Elexon Profile Class 1

Household consumption Norway[2] cold day and UK[3].



Act now rather than wait until the problems bite and expensive retrospective actions are needed.

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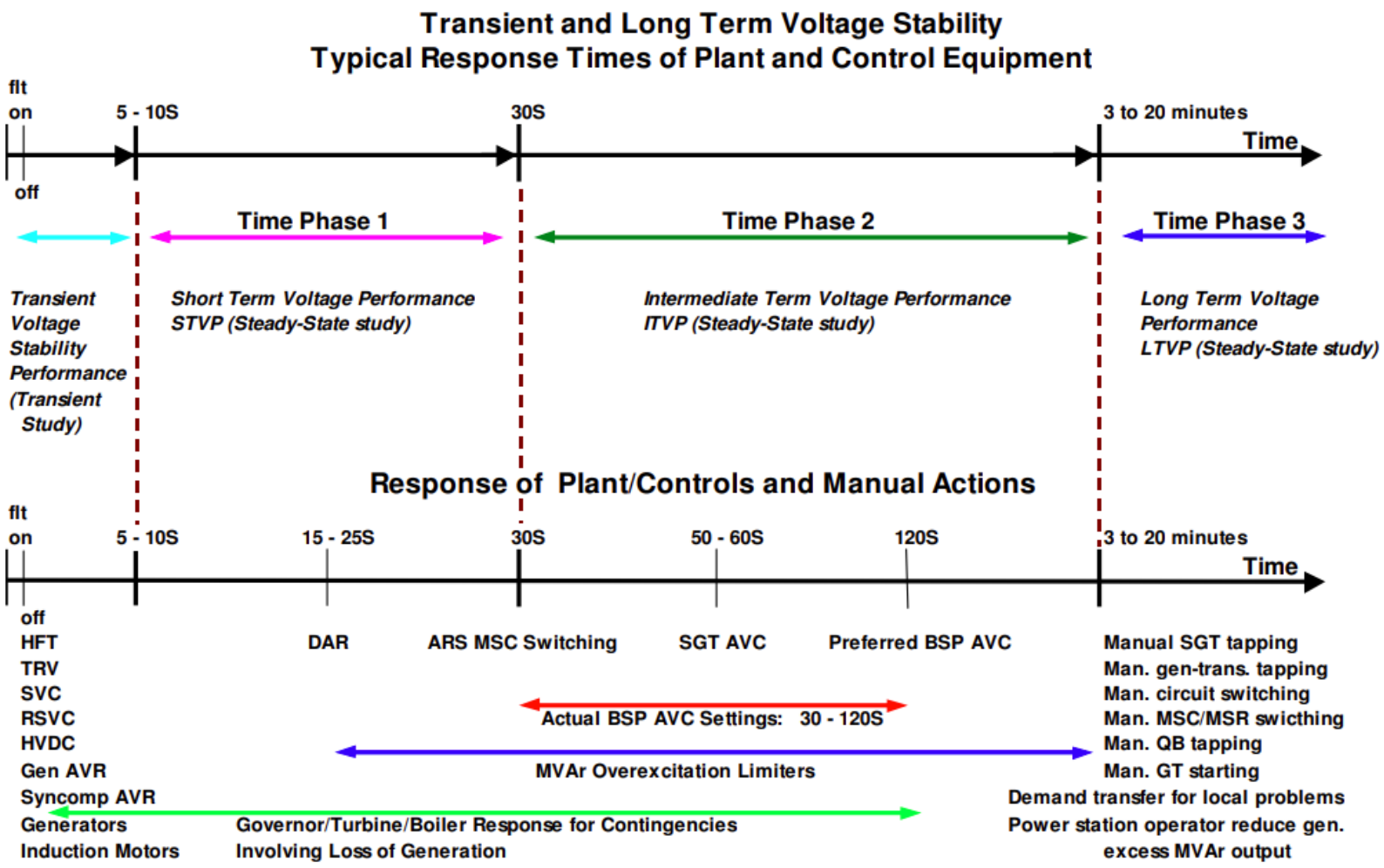
APPENDIX

Stability study time phases

This slide from a National Grid presentation [1] shows the four time phases used within stability studies and how they related to grid control mechanisms.



[1] Slide 12 from Hybrid Statcoms GCRP Update

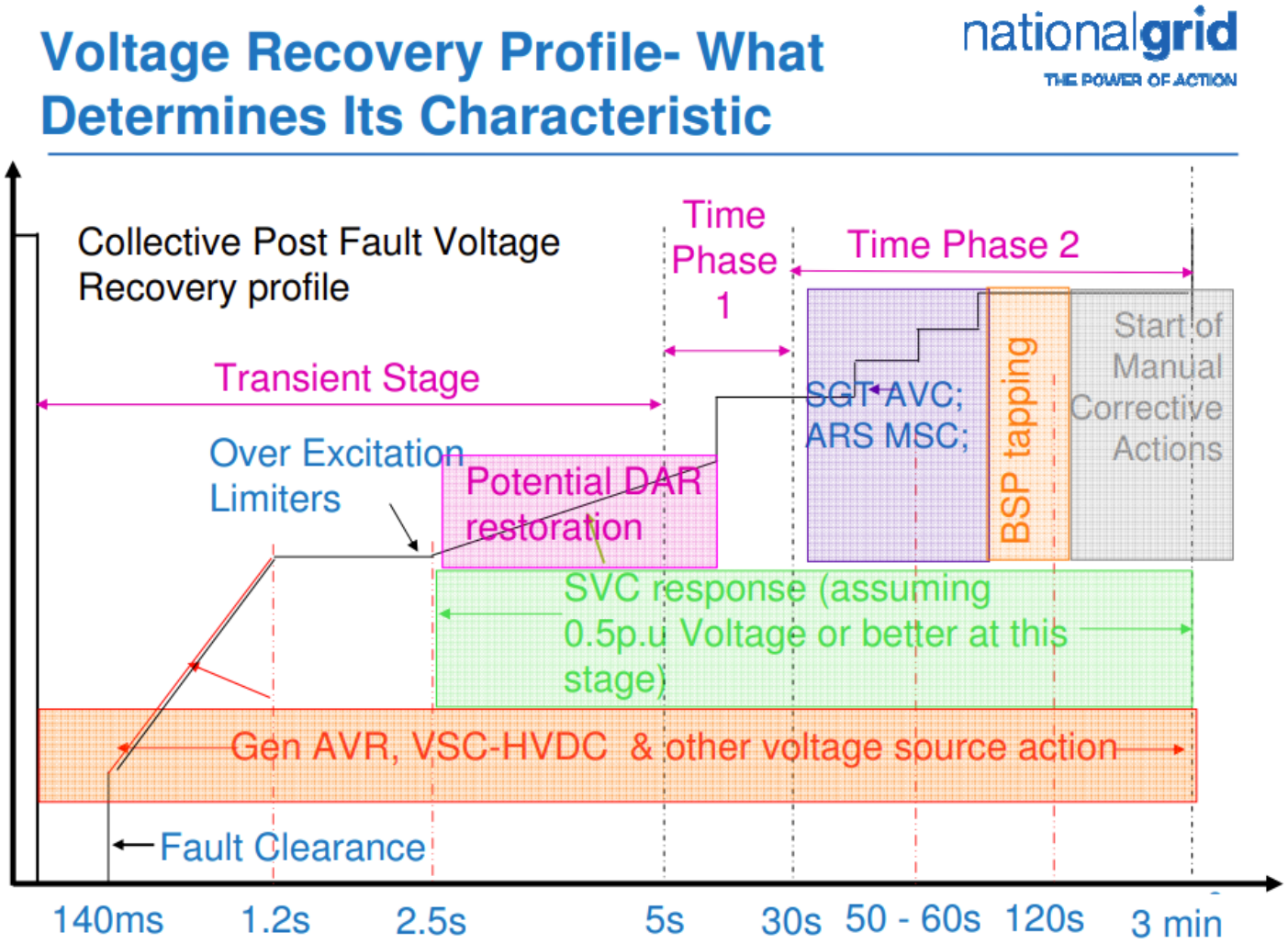
Typical EVC and V2G protection systems operate in the 'transient' time range up to 5 seconds.

APPENDIX

Voltage recovery profile

This slide is from a National Grid presentation [1] and shows the first 3 (of the 4) time phases used within stability studies and how they related to grid control mechanisms.

It provides detail of the transient phase which is most relevant to the interaction with EVC and V2G protection systems.



[1] Fault Ride Through Performance Requirements - The systems design context

EVC and V2G protection systems operate faster than many voltage control actions.