Powerloop: Trialling Vehicle-to-Grid technology

ESO & Octopus Energy group

June 2023

Glossary of technical terms

Term	Abbreviation	Description
Balancing Mechanism	**BM**	The primary tool used to balance supply and demand in each half-hour trading period of every day. The BM is used to either increase or decrease generation (or consumption)
Balancing Mechanism Unit	**BMU**	A unit which is registered to participate in the BM
Bid Offer Acceptance	**BOA**	The instruction from the ENCC to accept a market participants price to sell or buy energy to or from the system
Bid Offer Data	**BOD**	Prices a market participant is willing to sell energy (by increasing generation or decreasing consumption) to the system (offers) and to buy energy (by decreasing generation or increasing consumption) from the system (bids)
Balancing and Settlement Code	**BSC**	The legal document which defines the rules and governance for the balancing mechanism and imbalance settlement
Distribution System Operator	**DSO**	Operator of the power distribution system, which typically delivers energy to most end user
Electric Vehicle	**EV**	A vehicle that can be powered by an electric motor that draws electricity from a battery and is capable of being charged from an external source
Electricity National Control Centre	**ENCC**	GB's centralised hub for electricity system operation. Its role is to move electricity around the country from where it is generated to where it is needed
Electricity System Operator	**ESO**	Performs several essential functions; from second-by-second balancing of electricity supply and demand, to developing markets and advising on network investments
European Connection Conditions	**ECC**	The minimum technical, design and operational criteria for connection to the National Electricity Transmission System
Future Energy Scenarios	**FES**	A range of different, credible ways to decarbonise our energy system as we strive towards the 2050 target. Published by the ESO each year
Market wide Half-Hourly Settlement	**MHHS**	A faster, more accurate settlement process for all market participants, introducing site specific reconciliation using half-hourly meter readings
Maximum Export Limit	**MEL**	A series of MW figures and associated times, making up a profile of the maximum level at which a BM Unit may be exporting (in MW)
Maximum Import Limit	**MIL**	A series of MW figures and associated times, making up a profile of the maximum level at which a BM Unit may be importing (in MW)
Meter Point Administration Number	**MPAN**	A reference number used in Great Britain to uniquely identify electricity supply points such as individual domestic residences
Physical Notification	**PN**	A series of MW figures and associated times, making up a profile of intended input or output of Active Power
State of Charge	**SoC**	The amount of stored energy in an electric battery, as a proportion of its capacity
Vehicle-to-Grid	**V2G**	Bidirectional smart charging capability that also allows vehicle batteries to give back to the power grid

Executive summary

Objectives

In 2022 the Electricity System Operator (ESO) and the Octopus Energy Group collaborated on a first of its kind trial, looking to understand the viability of domestic Vehicle-to-Grid (V2G) enabled Electric Vehicles (EV) entering the Balancing Mechanism (BM) as an aggregated unit. The trial was a proof-of-concept piece with two high level objectives.

- **Understand viability of entry into the BM** – Understand the aspects of the BM framework and obligations that currently act as a barrier for V2G enabled EVs to enter this market.
- **Demonstrate the capabilities of V2G enabled EVs** – Demonstrate the capabilities of V2G enabled EVs when working in a BM framework, gathering insights into their ability to respond to instructions and the commercial viability of an asset of this type when compared against the current market.

Context/Approach

Over the coming decade, managing increases in energy intensive domestic assets will be one of the greatest challenges we will face as the system operator. According to our latest Future Energy Scenarios (FES)[1], we could see up to 35 GW of flexible capacity from V2G charging in 2035. The Powerloop project aimed to demonstrate a feasible model for domestic V2G enabled EVs. Collaborating on the project would allow us to understand more about this rapidly emerging technology, gaining vital insight into how they operate currently whilst understanding how they could play a role in energy balancing operations.

The trial was the first of its kind for the GB energy system, linking activities of the Electricity National Control Centre (ENCC) to end consumer's EV charge points, altering (dis)charging schedules to meet energy imbalances on the system whilst protecting customers' preferences. To avoid impacts on other market participants, the trial was run in a test environment and focused on two overnight sessions running from 17:00 – 05:00. 135 households were enrolled for the Powerloop project, with a combined maximum capacity of less than 1MW. Although the trial centred on V2G enabled EVs, the findings and conclusions drawn from the report are applicable to all types of EV smart charging, as well as offering a good insight into other flexible domestic assets.

Findings

- **Economic value for consumers –** Octopus Energy reported customers participating in the Powerloop V2G trial realised a saving of up to £180/y compared to smart charging, or £840/y compared to unmanaged charging on a flat tariff, when adjusted to an annual mileage of 10,000 miles.
- **Reduced balancing costs –** Through live tests with consumers, it has been shown that V2G enabled EVs could offer a cheaper option to balance the system than current alternatives in the BM, reducing all consumer bills whilst reducing reliance on carbon intensive fuel sources.
- **Capability of aggregating V2G enabled EVs –** Through trial sessions with households, we have shown the ability for the ENCC to alter (dis)charge patterns to meet energy balancing requirements, whilst still protecting end consumers' desired charging preferences. The trial demonstrated that, when aggregated, these domestic assets have the potential to meet the data requirements necessary for the BM, as well as consuming and delivering energy in response to an instruction.
- **Viability of entry into the BM –** Several barriers have been highlighted in the requirements of the current BM market framework and registration process. The majority of these were deemed to be short term barriers, such as minimum threshold and aggregation requirements, which will be overcome as the market for V2G enabled EVs grows over time. However, the current operational metering standards to enter the BM, in particular the types of measurements required and the accuracy an asset must take readings at, has been highlighted as a key blocker that needs addressing to unlock this new energy resource for balancing actions.

[1] https://www.nationalgrideso.com/document/263951/download (page 192 - Leading the Way scenario)

Next steps

The report has highlighted areas of review and refinement before this resource is ready to play a role in energy balancing activities. These will be reviewed and considered across the business, not just in relation to entry into the BM but also the role these assets could play across our other markets. We intend to continue to collaborate with providers in the space, collaborating through the Power Responsive[2] stakeholder group and CrowdFlex[3] project to understand how to best utilise these assets as the potential benefit to balancing activities increases significantly.

[2] https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive
[3] https://www.nationalgrideso.com/future-energy/projects/crowdflex

ESO

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Context

Powerloop Overview

The Powerloop V2G project was an innovation trial led by Octopus Energy and Octopus Electric Vehicles, with funding and support from Innovate UK and the Office for Low Emission Vehicles (OLEV). The project ran from 2018 to 2022 and equipped 135 domestic customers with the following V2G bundle:

- Nissan LEAF EV lease
- Wallbox Quasar bi-directional (V2G) charger
- Full G99 export approval[4]
- Consumer app
- Smart meter
- Time-of-use V2G import/export tariff

The project aim was to develop and demonstrate a feasible model for domestic V2G, exploring technical challenges, customer experiences and market possibilities.

Over the course of the project, customers enrolled onto a managed tariff with V2G charging and discharging automated by the Kraken platform[5], which was responsible for optimally scheduling the EV behaviour as well as settlement and billing. Customers were able to input their charging preferences (target State-of-Charge (SoC) and ready-by time) and view their daily V2G schedules through the Octopus Energy app; customer charging preferences were treated as paramount in V2G scheduling. Ahead of the BM trial phase, Powerloop demonstrated significant value potential for customers with a V2G electric vehicle on a managed charging and discharging tariff. In general, optimal behaviour included V2G discharging and export over the afternoon peak period, then charging overnight to reach the target SoC at the ready-by time.

Why the collaboration?

We collaborated with the Octopus Energy Group to use the Powerloop project as a testbed for the entry of flexible domestic assets into the BM. A recent survey of stakeholders that form the Power Responsive group[6] suggested there is around 500 MW of controllable EV charging capacity currently available across GB[7]. This chapter highlights the expected growth in this asset type and the challenges/opportunity this will bring. Our long-term vision is that market reforms (e.g. Market-wide Half-Hourly Settlement (MHHS)[8]) should ensure that balancing is driven by flexibility responding to wholesale market signals, with the ESO still acting as the residual balancer.

It was decided that taking a learn-by-doing approach, building an understanding of how V2G technology could interact with ESO operations, was a key step in unlocking the potential of this flexibility as soon as possible. The trial only worked with V2G enabled vehicles and charge points, however the findings are also directly relatable to one-directional smart charging. Although the flexible capability of one-directional smart charging is less than V2G enabled vehicles, the potential benefits for energy balancing activities still exists. Implementation is also much more plausible in the near-term for smart charging, given the current volumes of capable vehicles and charge points being far greater than V2G enabled assets.

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[4] https://www.ukpowernetworks.co.uk/electricity/distribution-energy-resources/installing-large-scale-distributed-generation
[5] https://octopusenergy.group/kraken-technologies
[6] https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive
[7] https://www.nationalgrideso.com/document/273096/download
[8] https://www.mhhsprogramme.co.uk/

Vehicle-to-Grid and Electric Vehicle growth

Our 2022 FES predict EV uptake to continue accelerating through the 2020s and 2030s, particularly following the announcement of the zero-emission vehicle mandate for new car and van sales.

Figure EC.T.07 – Battery electric cars on the road

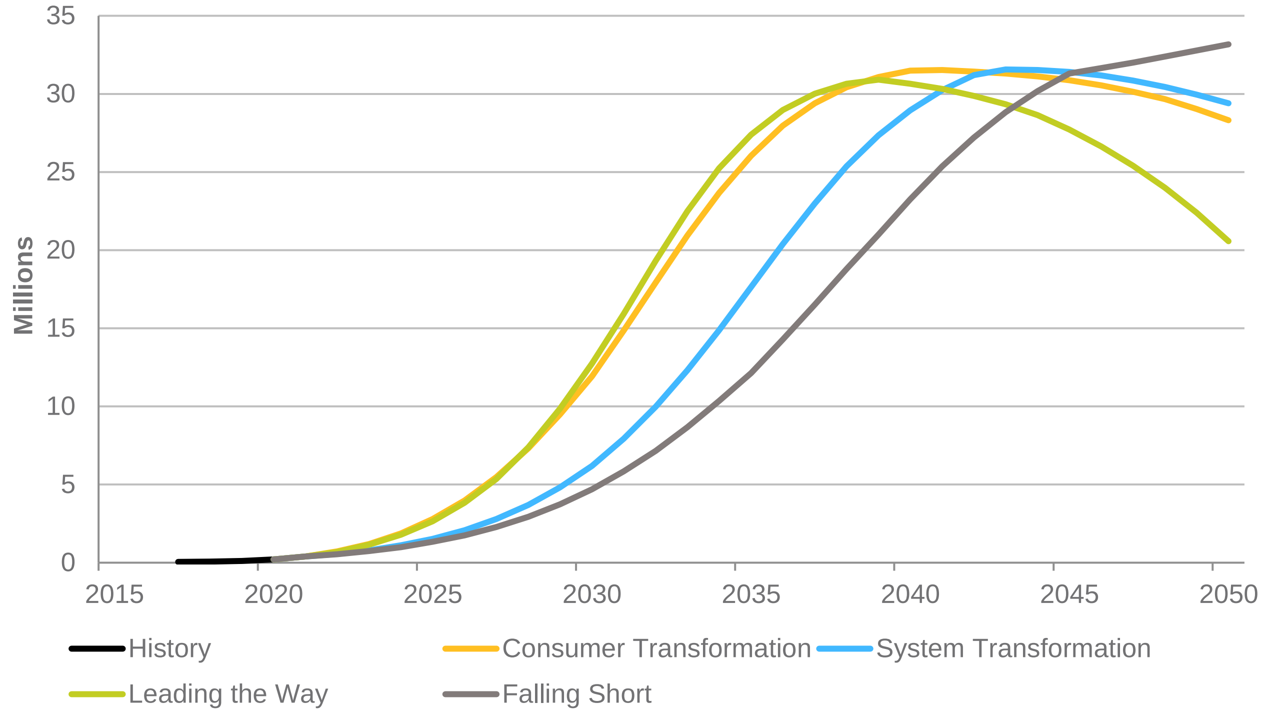
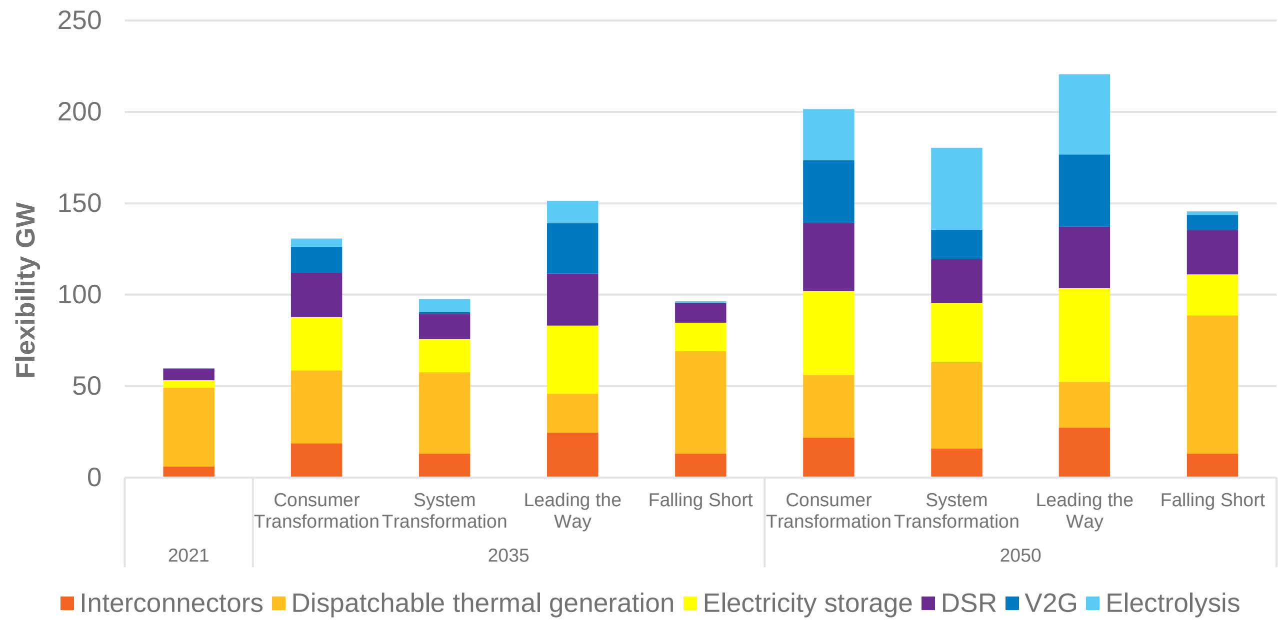


Figure EC.T.07 predicts that by 2035 we could see between 10 and 25 million battery EVs on the road. There is a variation across the scenarios in how EVs are charged, reflecting the differences in infrastructure development and consumer preference, with V2G utilisation being one of the options consumers may choose. It is predicted that there could be over 20% of consumers that engage in V2G charging by 2035, equating to flexible capacity of up to 35 GW (based on 7 kW charge points) on the GB network. That is equivalent to the peak system demand on a mild winter's day seen today. Predictions from the 2022 FES publication for expected flexibility from V2G are highlighted in Figure FL.03 below.

Figure FL.03 – Supply and demand flexibility in 2021, 2035 and 2050



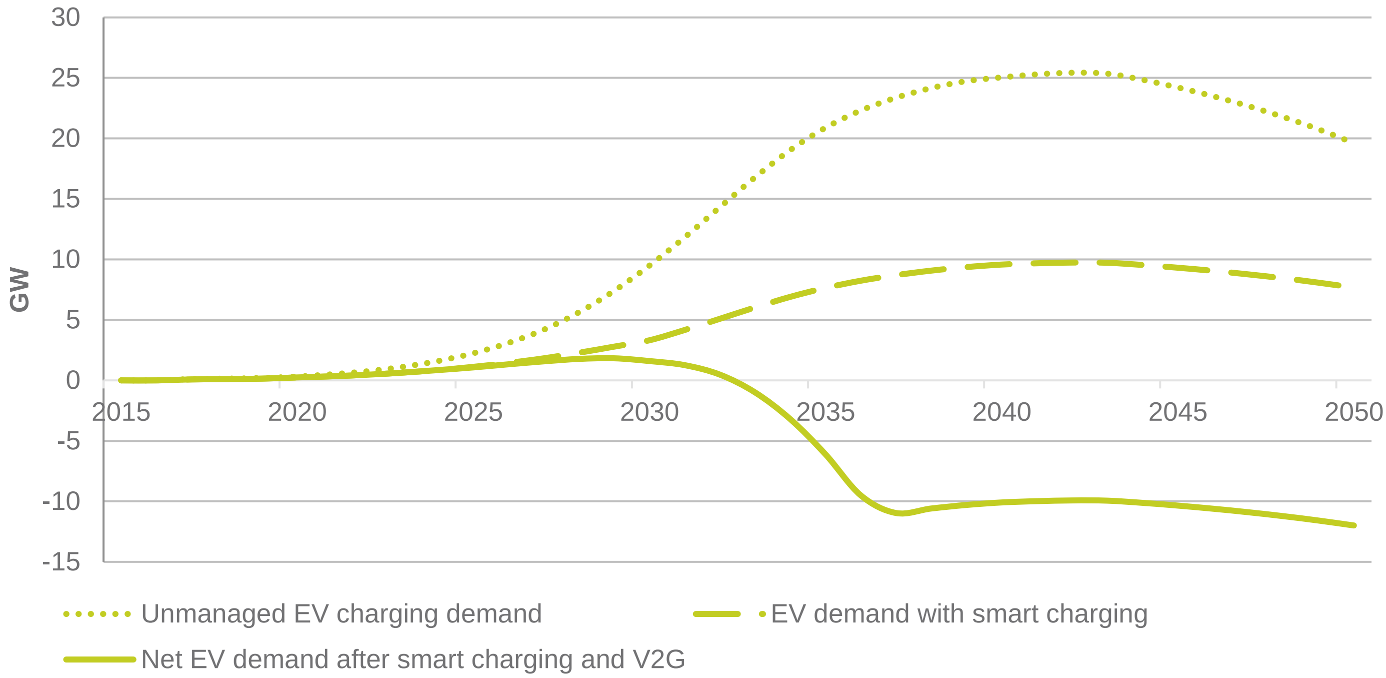
Challenges and opportunities from flexible domestic assets

Just as inverter-connected generation has brought new challenges for grid operation, the presence of new types of demand such as EV charging will introduce system risks that have not been seen before. The impacts of increased electrification on peak demand can be significantly reduced through smart charging and V2G technology. In fact, the ability to discharge means that V2G has the potential for a net negative effect on peak demand.

Across all scenarios in the 2022 FES, vehicles are primarily electrified, increasing electricity demands and requiring strategies to manage how they are charged and how system costs are distributed. However, the increased system flexibility presents an opportunity to integrate renewables via better matching of supply and demand. With suitable incentives and automation, drivers will be able to reduce their transportation costs at the same time as reducing the costs of operating the energy system.

Figure FL.12 from the 2022 FES publication predicts the impact of aggregate EV charging at Average Cold Spell (ACS) winter peak demand, based on different approaches to charging adopted by consumers for the 'Leading the Way' scenario. By 2040, it is predicted that the adoption of smart and V2G charging can provide 10 GW of power *injection* into the system, therefore helping meet other types of demand. With the electrification of other sectors (e.g. heating) expected to increase overall demand on the system, understanding how to manage and incentivise V2G and smart charging is a priority for us.

Figure FL.12 – Electric vehicle charging behaviour at ACS winter peak system demand – Leading the Way scenario



The 2022 Operability Strategy Report[9] highlights the importance of within-day flexibility to adjust the flexible parts of supply and demand as the inflexible parts vary over the day. EV smart charging and V2G technology has been highlighted as one of the fastest growing sources of flexibility to help address this future issue. The report recognises that the system needs for this flexibility may arise before market arrangements (such as MHHS, which will lead to faster, more accurate settlement through the use of site-specific hour-hourly meter readings) are able to correctly incentivise this. Therefore, the ESO may bridge the gap between stages by creating temporary alternative mechanisms to help price signals get through to new providers of flexibility. Energy suppliers have the option currently to register domestic properties to be elective half hourly settled, we therefore expect to see increasing numbers of tariffs promoting flexible demand/generation to meet price signals in wholesale markets from this sector. This should promote flexible generation and demand from the domestic sector matching variable supply from renewable generation, with the ESO still acting as the residual balancer to ensure this is matched exactly in real-time.

[9] https://www.nationalgrideso.com/document/273801/download

Why trial entry into the Balancing Mechanism?

The trial looked specifically at entry into the Balancing Mechanism, the primary marketplace that is used by the ENCC to manage energy imbalances on the system. Although there are ESO markets that have less stringent entry requirements, the BM allows us the greatest visibility of assets through a continual feed of forecasted behaviour and live metering. This increased visibility was important to ensure we gained the greatest insight from this asset type in the trial. Other markets we operate may be well suited to this type of asset, however they may have only provided insight into how an asset of this type would be operating when responding to instructions from the ENCC. Trialling in the BM allowed us to take learnings across a continual period, providing insight to how these assets interact with the energy system, something we do not typically have visibility of. This section explores the drivers for participation in ESO and Distribution System Operator (DSO) markets for suppliers and aggregators with flexible domestic assets, before looking at the suitability of these assets to the suite of ESO services available.

Drivers for participation in balancing markets

Energy suppliers must procure volumes of energy to cover the consumption of domestic households which they supply, for each half hourly interval. This procurement is completed through multiple different mechanisms, including bilateral agreements with generators (Power Purchase Agreements) and utilising day-ahead/on-the-day energy markets to buy and sell electricity right up to an hour before real time. At this point all contracted volumes are submitted to Elexon, the body responsible for administering the Balancing and Settlement Code (BSC)[10]. The ESO then takes over as the residual balancer, having this 60-minute period for real time balancing of the system, which is predominantly achieved through actions taken in the BM. Imbalance charges incentivise suppliers to balance their contracted positions with the actual outturn (or estimated outturn for non-half hourly settlement) of energy delivered. To calculate a household's consumptions for settlement purposes, there are two mechanisms that exist for domestic properties based on the readings that are available from the meters at the properties.

- **Non-Half Hourly (NHH) settlement** – Currently, most customers are settled on a 'non-half-hourly' basis, using estimates of when they use electricity based on a profile of the average consumer usage and their own (manual and likely infrequent) meter reads.
- **Half-Hourly (HH) Settlement** – Readings taken from smart meters at properties will flow directly through into settlement calculations, meaning for imbalance charges a supplier's contracted volume will be compared against the exact consumption of households in their portfolio for each half-hour. Suppliers must elect to have a property they supply move onto HH settlement through a process known as 'elective half-hourly settlement', currently only a small portion of the domestic market are settled in this fashion.

For **NHH settled households**, there is no benefit to suppliers attempting to alter consumer behaviour to match wholesale price fluctuations within a 24-hour period, due to being settled based on a standard profile.

For **HH settled households** there is an incentive for suppliers to promote shifting of household demand to match price fluctuations in wholesale markets, to ensure times of high demand match the lowest prices on the market and likewise low demand matches highest prices. With an asset such as a V2G enabled EV, suppliers should be able to take this a step further by discharging and charging the asset at the times of highest and lowest prices throughout a period, respectively. Provided suppliers pass through these savings, this will maximise the potential for customers to reduce their bills through shifting of charge schedules. This is a common concept known as energy storage arbitrage and is used by many providers across GB with alternative technologies, such as standalone batteries. Feedback from suppliers suggest that the price ranges seen in the wholesale markets do not offer a great enough incentive for them to feed benefits through to their customers. The prices seen in the BM provide a much greater case for energy storage arbitrage and therefore entry into this market will see a greater benefit for consumers and improve the economic case of V2G technology.

For any property to be a part of a unit that offers balancing services to the ESO via the BM, they must first be HH settled. Currently, domestic properties are NHH settled by default, with only suppliers able to opt-in properties they supply to be HH settled. This means for independent aggregators looking to utilise flexibility from assets behind a boundary point meter (e.g. EV charge points) in the BM, there is not a mechanism that

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[10] https://www.elexon.co.uk/bsc-and-codes/#:~:text=Consolidated%20and%20Sections-,The%20Balancing%20and%20Settlement%20Code%20(BSC)%20is%20a%20legal%20document,of%20electricity%20in%20Great%20Britain.

guarantees they can gain entry. This is the case even if the customer has agreed for an aggregator to manage their asset. This could be seen as a barrier to the ESO accessing flexibility from independent aggregators. MHHS will ensure domestic properties will be HH settled by default, therefore removing this barrier for independent aggregators and suppliers.

Electric vehicles entering ESO markets

Although to date domestic assets have not played a significant role in ESO markets, the introduction of smart technologies along with a cultural shift from consumers towards greater energy efficiency has led to more flexibility in how and when households use their electricity. Coupled with our drive to increase competition and facilitate easier access to our markets through the wider access scheme[11], we are seeing a greater interest from suppliers and aggregators wishing to participate in our balancing markets with domestic assets, including EV charge points.

Here we explore the different markets that are available, comparing the current capabilities of aggregated EV charge points with the requirements of the markets.

Table 1 gives a high-level view of all markets that are available to providers looking to enter with energy limited assets such as EV charge points, detailing the key parameters of each market that will help determine the asset's suitability. Table 1 is not an exhaustive list of ESO markets, it focuses on ones we believe are most applicable to this type of asset and highlights current markets as well as future proposed[12] markets. The key aspects of a market framework to consider when reviewing EV participation, as will become clear through the report, are; time to respond, minimum length of response, minimum volume requirement, aggregation locality, and metering requirements. Table 1 highlights when operational metering requirements may differ for BM and non-BMUs, if this is not referenced then the metering standards are either applicable to both or highlight the least stringent requirement for providers. Performance monitoring is required for settlement in certain markets, the table details what these requirements are.

It is worth noting that the devices used in this trial, and those being installed more widely, were not necessarily designed with ESO market entry in mind. If there was a clear pathway to entry for assets such as EV charge points, these limitations could be overcome by manufacturers and installers to ensure they do meet market requirements.

Each market has full technical requirements detailed in service terms which can be found on the relevant website pages that are linked in the tables. The Markets Roadmap 2023[13] provides details on the requirements for our services and how these are due to evolve over the coming years.

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[11] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-mechanism-wider-access

[12] Parameters and requirements detailed in table 1 are subject to change for proposed markets before implementation of these markets

[13] https://www.nationalgrideso.com/research-and-publications/markets-roadmap

Table 1 – Summary of key market framework parameters that are applicable for EV charge points

Market type	Market name	Current or proposed market	Length of time to respond (seconds)	Length of delivery (minutes)	Minimum volume requirement (MW)	Procurement window	Aggregation locality	Metering requirement
Frequency response	Static Firm Frequency Response (FFR)	Current	30	30	1	Daily auction	Nationwide	Real time active power/frequency measurement required, performance data upon request[14]
	Dynamic Containment	Current	0.5	15	1	Day-ahead tenders	GSP group	Real-time active power measurement at a rate of 1Hz. Performance monitoring requires active power/frequency measurement at a rate of 20Hz on an hourly basis
	Dynamic Moderation	Current	0.5	30	1	Day-ahead tenders	GSP group	As above
	Dynamic Regulation	Current	2	60	1	Day-ahead tenders	GSP group	As above however performance monitoring only required at a rate of 2Hz.
Reserve	Balancing Mechanism	Current	Defined by provider through dynamic parameters	15-minute maximum for energy limited assets	1	60 minutes ahead of real time	GSP group	Active power measurements required at 1Hz at an accuracy of +/- 1%. Full details can be found in Table 2 below.
	Short-Term Operating Reserve	Current	20 minutes	120	3	Day ahead	GSP group	Same as BM for BM units (BMUs). For non-BMUs, measurements required every 15 seconds (can include repeating reads up to every minute).
	Fast Reserve	Current	2 minutes	15	25	Optionally procured in real time	GSP group	Same as BM for BMU's. For non-BMUs measurements required every 15 seconds.
	Quick Reserve	Proposed	1 minute	15	1	Daily – 14:30	GSP group	To be decided
	Slow reserve	Proposed	15 minutes	120	1	Daily – 14:30	GSP group	To be decided
	Balancing reserve	Proposed	2 minutes	To be decided	To be decided	To be decided	To be decided	To be decided
Flexibility	Demand Flexibility Service	Current[15]	7.5 hours minimum	30	1	Day ahead – 16:30	GSP group	Active Power - Half hourly boundary point or asset metering
	Locational Constraint Market	Proposed	4 hours minimum	12 hours minimum	1	Day ahead (21:00) or on the day (13:00) auction	GSP – Must be above B6 boundary[16]	Active Power - Half hourly metering

[14] Real-time frequency/active power data required with a regularity that allows the unit to achieve their contracted volume by 30 seconds (not contractually defined), 1Hz granularity active power output required for performance monitoring (upon request from ESO).
[15] Currently going through a consultation phase to shape how this service will continue, therefore requirements are subject to change
[16] https://www.nationalgrideso.com/industry-information/balancing-services/pathfinders/noa-constraint-management-pathfinder#CMP-B6-Scotland-updates

The descriptions below provide some context to EV charge point suitability to each market type based on the information in Table 1.

Frequency response services

The ESO have a licence obligation to control system frequency within a 1% range of 50 Hz. We make sure there is sufficient generation and demand held in readiness to manage all credible circumstances that might result in frequency variations.

Currently there are several frequency response markets available to providers, addressing the different types of frequency deviations we need to mitigate against. Dynamic Firm Frequency Response (FFR) is being incrementally phased out with the introduction of our latest frequency dynamic services: Dynamic Containment, Dynamic Moderation and Dynamic Regulation. It is currently expected that tenders for Dynamic FFR will cease in 2024 and therefore is not referenced in the table above.

Of these newer suites of dynamic services, all three require performance monitoring data to be submitted to the ESO, to monitor delivery of response and to facilitate calculation of availability payments. The monitoring data needs to be at a granularity of 20 measurements per second (20 Hz) for each responding unit and comprises of data points such as active power and frequency, with a margin of error of +/-1%. The V2G bidirectional charge points being used as part of Powerloop did not record frequency and only took active power measurements every 10 seconds with a margin of error of +/- 8%, meaning the capability of the aggregated unit was significantly below frequency market requirements. Assets need to also be able to respond to frequency deviations within 0.5-2 seconds (market dependant), as the response time of the vehicles is currently not clear it was deemed best to trial a market that allows slower response times first.

Static FFR offer a better potential route to market for EV charge points, due to the longer notice period to respond to instructions and less frequent metering requirement for performance monitoring data. This still requires a response within a minute and metering at a granularity of every second, however.

Reserve

At certain times of the day, the ESO need access to sources of extra power in the form of either increased generation or demand reduction. This enables us to manage differences to forecast electricity demand or supply on Britain's transmission system. These additional power sources available to us are called 'reserve services.' The current suite of services available to providers have differing response time scales and minimum volume requirements, with 3 MW currently the lowest minimum threshold to take part in a market.

Given the scale of aggregation required, achieving this minimum threshold is seen as a prohibitive barrier. In the future, this is likely to be overcome by proposed new reserve markets with smaller minimum requirements, coupled with uptake of V2G and EV technology adoption increasing over time. Of all the markets available and proposed today, quick reserve offers possibly the greatest potential to market entry of all current and future markets. The low minimum capacity requirement (1 MW), short minimum length of response time (15 minutes) and the day-ahead auction tenders suit assets such as aggregated domestic EV charge points.

Flexibility services

The Demand Flexibility Service (DFS) was developed to allow the ESO to access additional flexibility when the national demand is at its highest, which is not currently accessible to the ESO in real time. This innovative new service allowed domestic consumers, as well as industrial and commercial users (through suppliers/aggregators), to be incentivised to reduce their energy consumption during specific periods. The requirements to participate in this service were proportionate to domestic metering capabilities, requiring half hourly granularity and 1 MW minimum aggregated unit size on a national level. This is a market that V2G and EV aggregated assets could have played a role in. The fact that aggregation for DFS was on a national level as opposed to the typical GSP grouping of other markets, which favours smaller aggregated units, shows there is an appetite for this in system balancing activities. At the time of the Powerloop market trial, this service was not available to market participants. It is the ESO's understanding that providers who manage domestic EV charging were active in this service and therefore will have been incentivising charging schedules being altered in response to events through the winter. DFS ran until March 2023 and is currently going through a consultation with industry participants to shape the future of the service. For the previous winter, the service offered a route into ESO markets for suppliers/aggregators with EVs in their portfolio, creating financial incentivises that could be passed through to end consumers for altering charging patterns. However, as this service focuses on when the system is most stressed, typically during peak winter days, and is currently used as a last resort mechanism, the market does not necessarily utilise the flexibility of EVs in the most effective way.

Local Constraint Market (LCM) is a proposed service that will primarily target assets that can provide flexibility within certain areas of the network, to help us manage constraints on the transmission network. LCM will be a demand turn up (or generation turn down) service for assets that sit above the B6 constraint boundary. Although localised to one area of the country and small regional areas required for aggregation, the requirement for metering only being half hourly makes this an attractive future market to EVs.

Balancing Mechanism

The BM is a core tool the ESO uses for managing the GB electricity system, accounting for a considerable portion of all contracted electricity volumes over a year. The BM is a platform used to ensure electricity supply and demand is balanced in real time. The minimum threshold for an aggregated unit to enter the BM is 1 MW and units can determine themselves how quickly they are able to respond to instructions sent from the ENCC, with the quickest response time being within 1 minute and the maximum of 89 minutes. Typically, the costs associated with actions taken in the BM are higher than other services as the value of flexibility closer to real time is greater, which makes this an attractive proposition for assets that can flex their output to match price swings. As a result, higher financial incentives for aggregated assets would hopefully be passed through to end consumers via lower upfront costs or ongoing costs of owning/running the assets.

Electric vehicles entering Distribution System Operator markets

All Distribution Network Operators (DNOs; often referred to as Distribution System Operators, DSOs, around their smart grid activities) now offer local flexibility markets to help them manage localised constraints. These flexibility markets create an additional route for suppliers and aggregators to realise value from the flexible charging of EVs. Typically, these are active power, demand turn down services that target assets in specific constrained areas of the DSOs network. They are usually procured through tenders that happen twice a year.

Balancing Mechanism framework

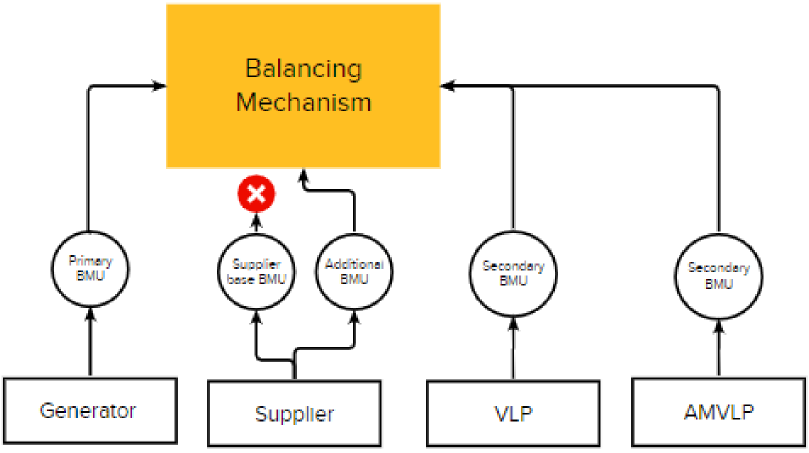
The BM is a continuously open online auction with thousands of instructions issued daily by the ENCC, the auction gate opens 60 minutes before real time. Beyond energy balancing, this market is used to address a wide range of other system needs beyond energy balancing, such as managing voltage levels. The BM allows the ESO to manage system changes and volatility close to real time. These flexibility needs cannot always be predicted and continuously change.

Full details of the BM framework can be found on the ESO website, including guidance documents for registration and code documents that detail obligations on providers. This section will focus on key elements of the BM framework that need to be considered when reviewing the suitability of aggregated EVs entering the market.

Entering the Balancing Mechanism

Recent changes to the BM have allowed for assets to be aggregated across a GSP group, opening the market to smaller-scale aggregated assets that could not meet previous aggregation requirements at the GSP level. The aim of this is to increase the amount of flexibility available to the ENCC and provide the right price signals to incentivise flexibility providers.

There are currently four routes to enter the Balancing Mechanism.



- **Generator** – Directly connected (transmission connected) primary BMUs and embedded primary (distribution connected) BMUs, typically power stations or other generating sites (e.g. wind farms) but can also be large demand sites. Equipment for each BMU is individually controlled and metered.
- **Supplier** – Energy suppliers must register fourteen base BMUs to account for all Meter Point Administration Numbers (MPANs) which they supply energy to within the different GSP groups across GB, these BMUs cannot participate in the BM. They have the option of registering '**Additional BMUs**', moving chosen MPANs they supply into a new BMU that can actively take part in the BM and is settled separately to the base BMUs.
- **Virtual Lead Party (VLP)** – A route to entering the BM for independent aggregators that are not the energy supplier to a given MPAN but can offer flexibility, typically from behind-the-meter assets. For settlement, MPANs move into a '**Secondary BMU**' and will make up part of an aggregator's portfolio. Recent changes from Elexon in the form of code modifications P375[17] & P376[18] have helped facilitate more accurate settlement processes for VLPs, through utilisation of asset level metering and baselining methodologies. An **Asset Meter Virtual Lead Party (AMVLP)** can now register a '**Secondary BMU**' utilising these recent changes, allowing settlement processes to take place at the asset meter level as opposed to the boundary point meter.

Recognising that V2G enabled EVs would not necessarily be scheduled by the energy supplier of the home, with many independent aggregators currently in the EV market, we decided to trial the VLP route and a Secondary BMU as opposed to the Supplier Additional BMU. The settlement process was not explored in the trial, with the focus remaining on the ESO registration process and capability of EVs to meet the physical requirements of the BM.

How does the Balancing Mechanism work?

Through communication channels between the market participant and the ENCC, data is transferred to ensure the ENCC has visibility on the activity of a BMU. They have the capability to instruct a unit to meet a requirement of the system based on certain physical parameters of the unit. Key data and process elements of the BM that were considered for the trial are defined below, these can be broken down into three elements: operational parameters, commercial parameters and operational metering.

Operational and commercial data are submitted to the ENCC to indicate the forecasted activity of a unit, the physical capabilities of the unit and the costs associated with altering the behaviour of the unit to meet system requirements.

Operational data

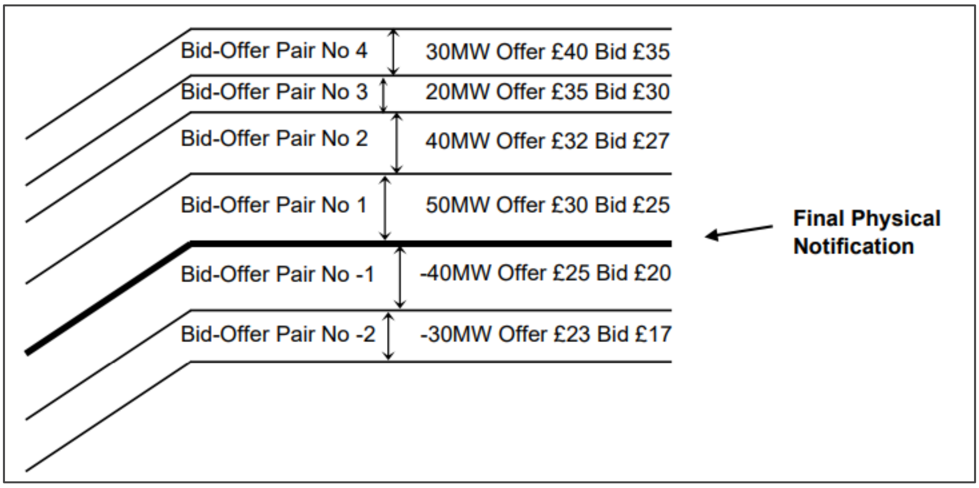
- **Final Physical Notifications (FPNs)** – MW profile of intended input or output of Active Power by a BMU.
- **Maximum Export/Import limit (MEL/MIL)** - profile of the maximum level at which the BMU may be exporting/importing (in MW) to/from the system.

[17] https://www.elexon.co.uk/mod-proposal/p375/
[18] https://www.elexon.co.uk/mod-proposal/p376/

- **Dynamic parameters** - technical data that detail the physical capabilities of a unit. This is not an exhaustive list of dynamic parameters, instead focusing on ones that were required for this asset type in the trial.
    - **Run-up/down rates** (expressed in MW/minute) – the rate at which the unit can move between certain imports/exports.
    - **Notice to deviate from zero** (NDZ – expressed in minutes) – The notification time required for a BMU to start importing or exporting energy, from a zero Physical Notification level because of a Bid-Offer Acceptance, expressed in minutes.
    - **Notice to deliver offers/bids** (NDO/B – expressed in minutes) **-** The notification time required for a BMU to start delivering Offers and Bids respectively from the time that the Bid-Offer Acceptance is issued.
    - **Minimum zero time** (MZT – expressed in minutes) **-** Either the minimum time that a BMU which has been exporting must operate at zero or be importing, before returning to exporting or the minimum time that a BMU which has been importing must operate at zero or be exporting before returning to importing, as a result of a Bid-Offer Acceptance.
    - **Minimum non-zero time** (MNZT – Expressed in minutes) -- The minimum time that a BMU can operate at a non-zero level as a result of a Bid-Offer Acceptance.
    - **Stable Export/Import limits** (SEL/SIL – Expressed in MW) **-** The minimum value at which the BMU can, under stable conditions, export/import.
    - **Maximum delivery volume** (MDV – expressed in MWh) **-** The maximum energy of an Offer (or Bid if MDV is negative) that a particular BMU may deliver within the associated Maximum Delivery Period (MDP), expressed in minutes; the maximum period over which the MDV applies.

<u>Commercial parameters</u>

- **Bid and Offer data** (BOD) – The price at which a participant makes volume available to increase or decrease their BMUs intended input or output by a given amount. The diagram details the data that is passed from the market participant to the ENCC, there are five price bands up and down to use.



These data parameters are used by the ENCC to inform decisions they make to meet system requirements and energy imbalances, ensuring the most cost-effective decisions are taken whilst maintaining the security of supply across the system.

Dynamic parameters and maximum import/export limits can be updated in real time to help reflect the capability of a unit, ensuring the ENCC has the most up-to-date information to allow informed decision making. For FPNs and BOD this can only be updated 60 minutes before real-time, or pre-gate closure, allowing ENCC engineers a window to make balancing decisions when the data is static, therefore ensuring the most economic decisions are made.

Operational Metering

Operational metering provides live metering from the asset to the ENCC, ensuring they have high resolution visibility of the current activity of the unit. The requirements for operational metering are driven by the ENCC needing to balance generation and demand every second and have visibility of the actions taken to control system frequency. When providers are registering to enter the BM, they are required to sign a bilateral agreement that stipulates all the regulations and requirements that need to be met.

As part of the bilateral agreements between market participants and the ESO for BM entry, providers are required to meet special automatic facilities and schemes set out in Appendix F5 of the agreement. This appendix details all the European Connection Conditions (ECC)[19] that apply for new providers; schedule two of the appendix details the operational metering requirements that need to be met by assets to enter the BM. These specify the metering requirements at an aggregated level, detailing which measurements are required. The requirements regarding read frequency and accuracy are stipulated by the ESO and not detailed in the ECC explicitly. Table 2 highlights the standards that must be met to ensure we can balance the system safely and economically.

Table 2 – Operational metering standards currently required by market participants entering aggregated assets into the BM, as detailed in bilateral agreements with the ESO. All meters should have a latency value of less than or equal to 5 seconds.

Aggregated signals (Including sub units <1 MW)	Range	Scale (unit)	Accuracy	Resolution	Refresh rate
Active Power	-1000 MW to +1000 MW	MW	1% of meter reading	1 kW	1 per second
Reactive Power	-1000 MVAr to +1000 MVAr	MVAr	1% of meter reading	1 MVAr	1 per second
Power Available	0 – 1000 MW	MW	1% of meter reading	1 kW	1 per second
State of Charge (Energy) Import/Export	0 – 100%	%	1% of meter reading	1%	1 per second
Energy Available Import/Export	0 – 1000 MWh	MWh	1% of meter reading	1 MWh	1 per second

[19] https://www.nationalgrideso.com/industry-information/codes/grid-code-gc/grid-code-documents

Trial Approach

Test Environment

The trial was conducted in a test environment outside of live market operations, as will be described in more detail later in the report. This allowed us to neglect certain BM rules that would have posed a barrier to entry for the aggregated portfolio of EVs to the live market; it enabled us to build valuable learnings whilst also assessing how these barriers-to-market could be overcome in the future. Specifically, the barriers identified were the following:

1 MW minimum unit size

Currently there is a minimum size of asset, either aggregated or single unit, which can enter the market of 1 MW. With 135 vehicles involved in the Powerloop project, a maximum delivery capacity of the fleet would be 0.95 MW and would not reach this threshold. This would be exacerbated by not all vehicles being available to participate in all trial events.

Aggregating assets only within one GSP group

The current market requirements for the BM only allow aggregated units to comprise of assets that are all within the same GSP group. Vehicles involved in the Powerloop project were not geographically clustered, instead spanning all 3 GSP groups within the UK Power Networks distribution region. To give the largest aggregate portfolio, therefore maximising the learnings from the trial, all vehicles were combined into a single BMU for the purposes of the trial.

Operational metering requirements

A live metering feed for the trial BMU was not set up during the trial, due to constraints in time and systems. The impacts on ENCC operations would be negligible from the unit, so focusing efforts and resourcing on other elements of the trial were prioritised. It was instead decided that metering would be assessed as a post event exercise. The accuracy, resolution, refresh rate and latency of readings that were available from the charge points used in the trial are detailed below in the ‘VLP Approach – Software/Hardware’ section. The current metering requirements on providers is reviewed in detail in the ‘Results – Viability of entry into the BM’ section.

Virtual Lead Party Approach

Software/Hardware

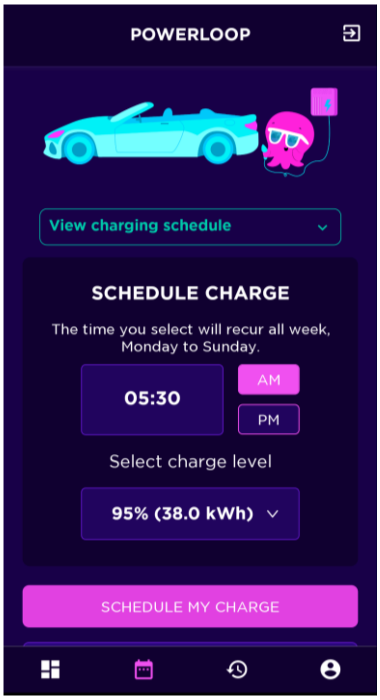
<u>Nissan LEAF EV</u>

All EVs in the Powerloop fleet were 2019-model Nissan LEAFs. Customers entered into personal lease agreements as part of the trial and were able to select any specification package for their vehicle, including the larger 62kWh battery option rather than the standard 40kWh. The Nissan LEAF was one of the few V2G enabled vehicles commercially available in the UK at the time of the trial.

<u>Wallbox Quasar bi-directional charger</u>

A Wallbox Quasar bi-directional charger was installed for each participant in Powerloop, facilitating smart charging and discharging of their Nissan LEAF EV. Full G99 export approval was obtained for each property, enabling the entire 7kW discharging capability of the Quasar to be used. The Octopus Energy Kraken platform integrates with the Quasar via an internet connection, instructing optimised charging and discharging behaviour each time the EV is plugged in. The Kraken platform was used to communicate with the ENCC, instructing the desired charging and discharging behaviour based on BM dispatch signals. Information gathered by the charge point was communicated back to the Kraken platform:

- Current SoC of the vehicle (%)
- Active Power measurements (kW)



Once a vehicle had been plugged in, these measurements were available at a frequency of every 10 seconds, with an accuracy error band of +/- 8% (non-systemic) of the true value.

Octopus Energy app

The Octopus Energy app put customers in control of their charging outcomes, allowing them to specify and change their target SoC and the ready-by time to reach this level of charge. This customer-first approach included a minimum SoC of 30%, ensuring that EVs were always ready for any unplanned use, even after discharging had occurred.

This system meant that the end user could alter charging targets, or unplug the EV, at any time. Any changes are incorporated by the Kraken platform as an updated schedule and are communicated to the fleet optimiser as described below.

Default charging targets were 85% target SoC and ready-by time 05:30 (BST); 80% of the 135 households involved had adopted these settings. Many of these EVs were second vehicles and tended to be plugged in with a high SoC (>60%) at 4pm.

Powerloop Import and Export tariffs

Customers in this trial used the Powerloop Import and Export tariffs, together forming a managed time-of-use tariff with automated scheduling by the Kraken platform. The tariffs included a static off-peak period for the import tariff (incentivising charging) and a static peak period for the export tariff (incentivising discharging). This structure incentivised charging overnight, exporting during expected peak network times and facilitated automated charging and discharging at preferential rates. Static time-of-use rates provide a level of consistency that benefits customer comfort. In addition, the preferential rates were also applied to periods of charging and discharging scheduled by the Kraken platform, allowing flexibility for automatic scheduling without disadvantaging the customer.

The tariff structure was based on day-ahead wholesale price patterns, however the pricing was improved beyond the market benefit alone to reflect the expected additional revenues that could be achieved via BM access (these additional benefits are required to make an attractive customer proposition today, where the day-ahead wholesale market alone does not provide a sufficient signal for flexibility).

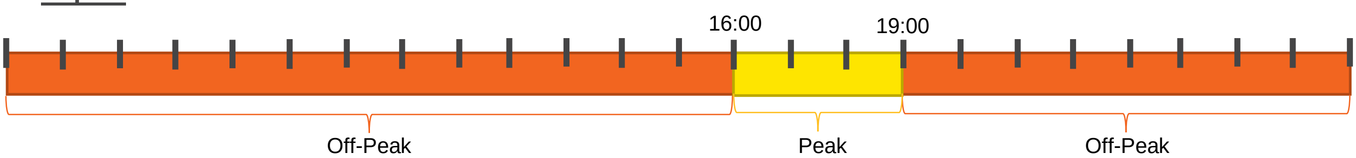
Table 3 represents the timing and pricing structure of the import and export tariffs; note that unit rate and standing charges vary based on location due to network charge differences incurred by the supplier, therefore the below just represents average prices.

Table 3 – Tariffs rates applied to customers partaking in the Powerloop trial

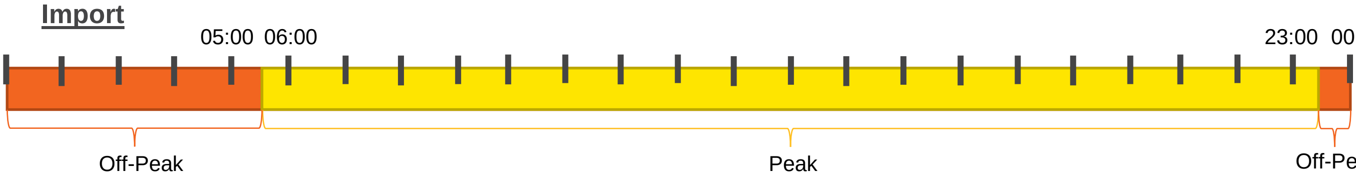
Tariff type	Peak		Off-peak	
	Time	Unit rate (p/kWh)	Time	Unit rate (p/kWh)
Export	16:00 – 19:00 (or during automated discharging)	15	Any time outside of Peak times	5
Import*	Any time outside of Off-peak times	16	23:30 – 05:30 (or during automated charging)	5

*Standing charge of ~25p/day also applicable

Export



Import



Fleet optimiser

Octopus Energy undertook the role of a VLP aggregator for the trial. This necessitated several control and communication functions which were performed by a software component termed the 'Fleet Optimiser' that was built across its Kraken platform. Firstly, an optimised (dis)charging schedule was composed for each individual vehicle, considering customer preferences from the consumer app and state-of-charge information from the charge point. The set of individual charge schedules, and the known capabilities of the individual charge points, were aggregated to provide the operational parameters for the portfolio as a whole, which were submitted to the ENCC trial environment through the wider access API communications pathway. Upon receipt of BM dispatch signals, the schedule of each individual vehicle was updated, and corresponding parameters resubmitted to the ENCC.

Operational metering aggregator (not calculated live in the trial)

Recognising that few of the operational measurements required for entry into the BM are available from EV charge points, the trial focused only on the active power measurement. As we were working in a test environment, the direct metering feed was not established with the ENCC, therefore analysis of metering was done offline post-event. The methodology for the combination of meter readings was to provide an aggregate feed at 1 Hz granularity, based on the most recent reading from each charge point. This enables a feed that changes every second, even though the individual readings only change every ten seconds, due to individual readings are updated asynchronously.

ENCC approach

Incremental approach

We adopted an incremental approach to how we trialled the system, testing communications between parties and functional capabilities of the vehicles before full stage commercial testing against live market operations. This allowed us to build confidence in the test environment and communication pathways, as well as helping control engineers understand how the unit would operate for the commercial trial. The staged approach meant issues could be identified and direct feedback from control engineers could be provided before live testing in the ENCC. It also gave us the ability to observe the vehicles' ability to respond to varying types of instruction, proving the capability of the unit in responding to all the different instruction types. The stages were chosen to replicate those used in entry testing for real BMUs.

Below details the incremental approach used, the remainder of this report focuses on Stage 3 below, as this was the full end to end trialling process.

Table 3 – Incremental stages to testing adopted during trial

Stage	Overview	Reason	Methodology	Result
Stage 1 – Communication	End-to-end data connections between ENCC and API used to dispatch vehicle charge points.	Ensure communication connection with control point and vehicles. Also build familiarity of test environment and unit for ENCC engineer	Set date, time and defined set of instructions sent from ENCC to Octopus Energy Control point. First signal sent to confirm connection with control point, second signal sent to show connection to actual vehicles.	Six vehicles producing an export response of 40.8kW – the first time we have had a response from an EV based on a signal from the BM.
Stage 2 – Functional	Assessing the ability of vehicles to respond to a wide range of instructions typically sent by ENCC to BM assets.	Prove the vehicles' ability to respond to typical instructions the ENCC send through the BM.	Agreed a set of instructions and a defined hour period the signals would be sent to vehicles, reviewed output of vehicles through charge point metering.	Ability of vehicles to respond to typical BM instruction types* - Short notice bid (< 10 minutes) - Long notice bid (> 10 minutes) - Bid extensions - A bid followed by an unwinding instruction
Stage 3 – Commercial	Full trial environment to assess the viability of EVs	Understand if the trial BMU would be dispatched in live market conditions	Two mid-week overnight slots (17:00 - 5:00) with the aggregated vehicles acting as a BMU with live data submissions and BOD	Vehicles acting as a live BMU, responding to instructions sent from ENCC engineers to meet energy imbalances as required.

	acting as a live asset in the BM.	based on their price submissions, whilst showing the ability of the asset to respond to range of instruction types.	prices. ENCC engineers dispatched vehicles through the test environment if they were priced more favourably than live assets. Therefore, replicating true operations were the asset to be live in the BM	For full details see results section of report.

* Note during this phase of testing we did not have the exporting capability of the vehicles, hence why instructions were focused only on bids to increase the importing volumes of the fleet.

BM Test environment

It was recognised from the outset that certain requirements of the BM make it difficult for this asset class to enter the market in its current form, as highlighted in the trial design section. For this reason, and to facilitate a learn-by-doing approach, the trial worked in a test environment outside of market operations and settlement processes. This allowed the study to focus purely on the capabilities of the EVs when aggregated into a single unit, understanding how assets of this type could interact with ENCC activities and BM market dynamics without impacting other market participants.

The user interface of the test BM environment exactly replicated the live BM environment and is a tool normally used for onboarding new participants. The only differences between the test and the live environments were operational, as follows.

- No data feed from live assets outside of the trial; received a snapshot of data daily from live BM systems
- Instructions initiated were not sent to any assets unless specially set up to do so, which is what we did for the test unit in the trial
- Any updates from control engineers in live systems (e.g. setting demand forecasts for given regions) were not reflected in the test environment

It is worth pointing out that this test environment was not built for trialling purposes, therefore difficulties were faced around connectivity and support during the trial process, which did have an implication on the results (see Graph 2 in the results section). Since this trial, work is underway to review the capability we have across the ESO to run trials, exploring ways of improving current channels to ensure a smooth trialling process[20].

Wider Access API communication path

The Wider Access API route for the transfer of data parameters and instructions (detailed below in Data/Process section) was the chosen communication path between the VLP and the ENCC. This is a new communication route brought in by the ESO in 2019 to allow easier access to the BM for newer, smaller-scale market providers who do not have the access to the standard routes of EDT/EDL fixed lines. More can be found out about communication paths to the ENCC in the communications standards[21], found on the balancing mechanism wider access area[22] of the ESO website.

ENCC engineer view

Over the full trial periods (stage 3 above), an ENCC engineer compared the capabilities and price of the trial BMU to the rest of the market, as they would do were this resource available in the live market. They then dispatched the test unit whenever it was favourable in price, replicating true operation. Control engineers would still dispatch units through the live market to meet the energy imbalances on the system, meaning these events had no impacts on wider participants or actual market operations.

To review the trial BMU operational and commercial parameters the control engineer implementing the trial process took an additional laptop on shift; this had the test environment loaded allowing them to see live updates from the trial BMU. When making dispatch decisions in live systems to meet genuine energy imbalances, the control engineer would make manual comparisons between the live market and the test environment. Due to the manual nature of this process and the pressures on an ENCC control engineer from

[20] https://smarter.energynetworks.org/projects/nia2_ngeso024/
[21] https://www.nationalgrideso.com/document/33331/download
[22] https://www.nationalgrideso.com/industry-information/balancing-services/balancing-mechanism-wider-access

regular shift requirements, the comparison was not done for every action the engineer took and focused on around 5-10 actions for each overnight window.

Data and process

All data for the trial was aggregated for the entire fleet of vehicles and corresponded to the EV charge points only, therefore there was no impact from household load on the data.

Scaling up

As well as the 1 MW minimum requirement to enter the BM (as highlighted in the 'Test environment' section of the report) there is also a current requirement on providers to submit operational and commercial parameters in whole MW integers. Given the available capacity of the full set of vehicles would not reach the full 1 MW alone, it was accepted that enforcing whole MW integers for all data submissions would reduce the learnings from the trial.

Recognising that the existing systems (including test systems) can only accept whole integer values, the decision was made to add a scaling factor of one hundred to data submissions from the market provider. This would provide greater granularity in data submissions, making the BMU easier to characterise for control engineers, allowing more flexibility in the types of instructions that could be sent. Graphs in the results section will be reflective of the actual capabilities and output of the asset (in kW), as opposed to what the control engineer would have seen in the BM test environment.

Dynamic parameters

As mentioned earlier in this report, the BM framework requires market participants to provide a range of technical parameters that reflect the capability of the unit in real time. Six of the dynamic parameters were fixed and static for the duration of the trial, some as they were being reviewed through the trial process, others simply reflected the capability of the unit and highlighted the highly flexible nature of the unit. Parameters that remained static and fixed were.

- **Run-up/down rates** – 999 MW/min (Reviewed throughout the trial – see response times in results section)
- **Notice to deviate from zero** – 0 minutes
- **Notice to deliver offers/bids** – 1 minute (Although not tested down to this granularity, all instructions were sent with at least a 3-minute window to deliver against, see section on response times in results for more)
- **Minimum non-zero time/Minimum zero time** – 0 minutes
- **Stable Import/Export limit** – 0 MW (It is noted that whilst this parameter could in theory be used to protect the charge schedule of a customer, the framework currently dictates that this must reflect the engineering capability of a unit, and not include any commercial considerations)
- **Maximum delivery volume** – This was not used as a data parameter in the trial as it is not considered in current optimising software in the ENCC, therefore would have been too much of a time burden for the control engineer to consider whilst running the trial. Instead, the principle that is currently applied by storage providers in the BM was used, as detailed below.

Physical Notifications

These were calculated by aggregating the planned (dis)charge schedule of each household, creating a single forecast of activity for the fleet. As instructions were sent from the ENCC, the schedules would be updated (via the fleet optimiser) to meet the required energy need in the immediate term. Alterations were also required to the schedules following the energy balancing activity (1 hour in the future and beyond), to ensure the customers charging preferences were still met. These updates to the future schedules were fed back to the ENCC via a revised Physical Notification (PN).

Maximum import/export limits

As the trial relied on manual comparisons between the live market and the test environment, the definition for how MEL/MIL was used in the trial differed from live market conditions. Instead of reflecting the physical capability of the unit, it instead represented the maximum and minimum output that the market provider was prepared to move the unit to. This was to ensure only one price tranche was used for bids and offers, allowing ease of comparison against the live market for the ENCC engineer.

In live market conditions, the market provider would price themselves out of competition for the range between the MEL/MIL used in the trial and the actual physical capability of the unit.

The MEL/MIL submission also followed the existing principles of the live BM market framework for energy limited assets such as batteries. The BM system architecture has some limitations in its representation of storage assets, which we are working towards developing system solutions to factor real time stored energy capacity/capability of energy storage assets within the BM. Until this work is delivered, energy limited BMUs should declare their MEL and MIL open-ended such that it reflects the capacity to follow a Bid Offer Acceptance (BOA) which ramps from the current PN to the MEL or MIL and remains at there for a duration of 15 minutes before ramping back to the PN. If a 15-minute BOA is issued, the provider can update their MEL/MIL for the end of this BOA to reflect the new energy state of the fleet.

Bid/Offer Prices

To reflect realistic conditions, the prices used by the provider were derived from day-ahead wholesale prices, varying on a half-hourly basis; since the provider would want to participate in the BM only when this action offered a revenue benefit compared to wholesale arbitrage.

As mentioned above, only one tranche for the bid/offer prices was used by the market participant in the trial, this was to help with the manual elements of the trial process. In live market conditions operations, it is expected that providers would utilise different price tranches to price out actions that were incompatible with customer charging preferences.

Results

Capability of aggregating V2G enabled EVs

Across the two evenings of live trialling, we were able to gather insights into how a BMU composed of V2G enabled assets would act in the BM framework. There were fifty vehicles from the Powerloop cohort that were available to participate at the time of trial; the number that had been onboarded onto the Kraken platform by that time (required to participate in the BM).

The scheduling of vehicles was amended to include BM participation, but only when the participation of individual vehicles did not affect their ability to meet the customer preferences. In this way, the collaboration demonstrated market entry, bringing benefits to both the system and each individual participant, without sacrificing user comfort.

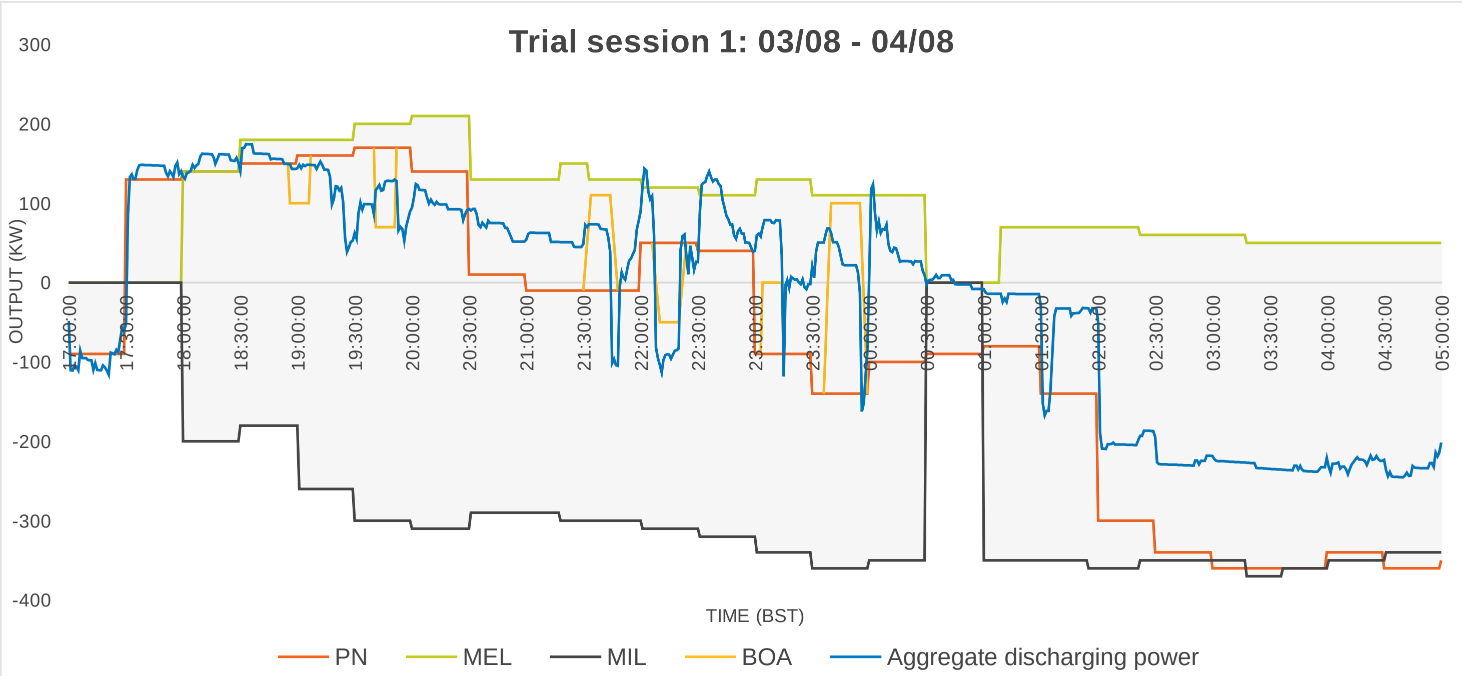
Due to the nature of the trial, we were able to review key elements of the BM framework that we wished to explore with this new energy resource. This covered operational parameters, metering capability and commercial viability of the aggregated asset.

Key insight – Operational parameters

Operational parameters were highlighted earlier on in the report as fundamental for ENCC engineers to view activity and capability of an asset operating in the BM. Meeting certain data and capability requirements is essential to be able to enter this market. Below gives an operational breakdown for each of the trial sessions, mapping the key parameters and outputs from each of the trial sessions as they happened in real time.

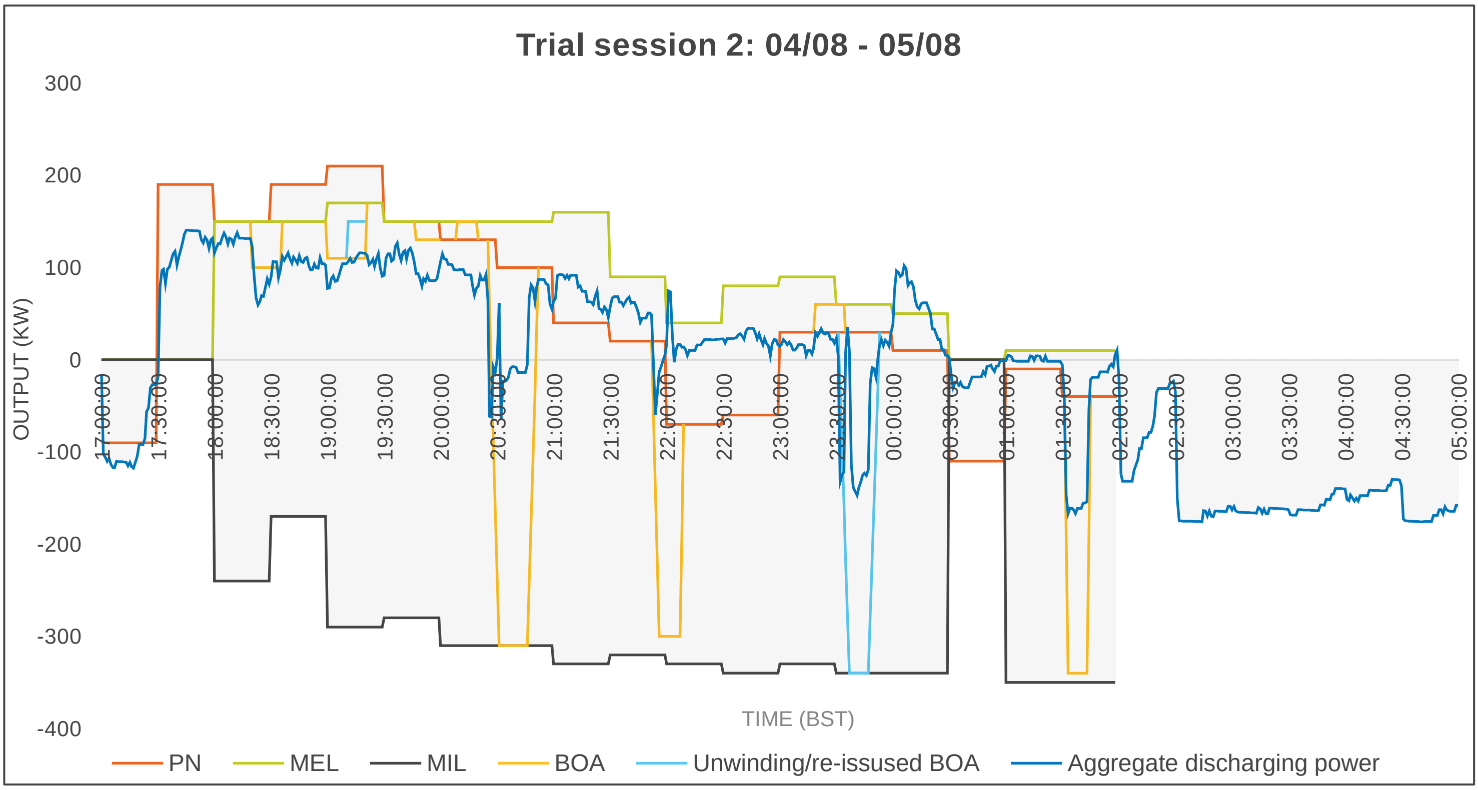
All values are reflective of the capability and output of the vehicles when aggregated, they do not consider the loads of the sites the charge points were connected to (as opposed to the power exported to the grid). It is worth noting that during the trial sessions there were around thirty vehicles on average responding to instructions sent from the ENCC. Therefore, scale is a careful consideration when reviewing the accuracy of data parameters such as PN, MEL/MIL and response to instructions. A few vehicles not responding in the desired way can lead to significant differences on the graphs below, however as you scale up to a fleet of over 150 vehicles (minimum threshold to enter the BM), the same number of vehicles has a significantly reduced impact on the activity of the aggregated unit.

Graph 1 – Operational data from trial session 1 (17:00 03/08/2023 – 05:00 04/08/2023)



The shape is indicative of the typical activity we could expect to see from an aggregated unit made up of V2G enabled EVs. The highest aggregate discharging takes place from 17:30 to 19:00 when wholesale prices are highest, then tails off until around 21:00. Most of the charging occurs from 02:00 onwards when wholesale prices are lowest. The tariff is reflective of these prices, with high and low prices over those periods respectively, but it should be noted that scheduling was based on daily wholesale prices.

Graph 2 – Operational data from trial session 2 (17:00 04/08/2023 – 05:00 05/08/2023) *



**Due to a loss of connection with the test environment no data was able to be received or sent to/from the market participant after 02:00, hence many of the data fields finishing here in the graph.*

Again, for the second session the expected behaviour of the fleet was to be largely exporting until around the 23:00 time, which will have been driven by wholesale pricing. The setting of the PN and MEL initially had issues with PN being greater than MEL but following 19:00 this was no longer an issue. Based on the actual output from the fleet, it is believed the errors were in the MEL setting for these initial periods.

Forecasting PNs

Graphs 1 and 2 show the ability of Octopus Energy to convert their individual optimised charge schedules into an aggregated PN that fed into the ENCC systems. This provided a forecast of output from the aggregated unit, allowing good visibility for the ENCC to make informed decisions. At the time of the trial, the system was an early-stage product and communications dropouts were common; this can be observed as a discrepancy between meter data and the forecast PNs. This would be a clear focus area for future improvement. Communications dropouts would remain, but it is envisioned that these (few) would be negligible at large fleet sizes, where stochastic deviations in individual device behaviours become noise when compared to the aggregated fleet.

Forecasting MEL/MIL

As detailed previously, the maximum/minimum limits were used slightly differently in the trial than they would have been in live operations. The limits represented the capability of the BMU with customer preferences being protected and prioritised. Overall, these seemed a good representation of the unit's capability, with the aggregated discharging power rarely exceeding the minimum/maximum limits. However, bids sent during the second session that looked to assess the ability to reach the MIL show that the trial BMU was unable to reach this minimum level, suggesting that it was set too low.

Both the PN and MEL/MIL were updated upon receipt of each BOA, after corresponding updates to the schedules of the vehicles. This is a critical mechanism for incorporating recovery after BOAs into future (dis)charging behaviour. Again, however, the exact values set through this process need to be improved in the future to ensure they correctly represent the expected capability of the unit.

Ability to respond to instructions

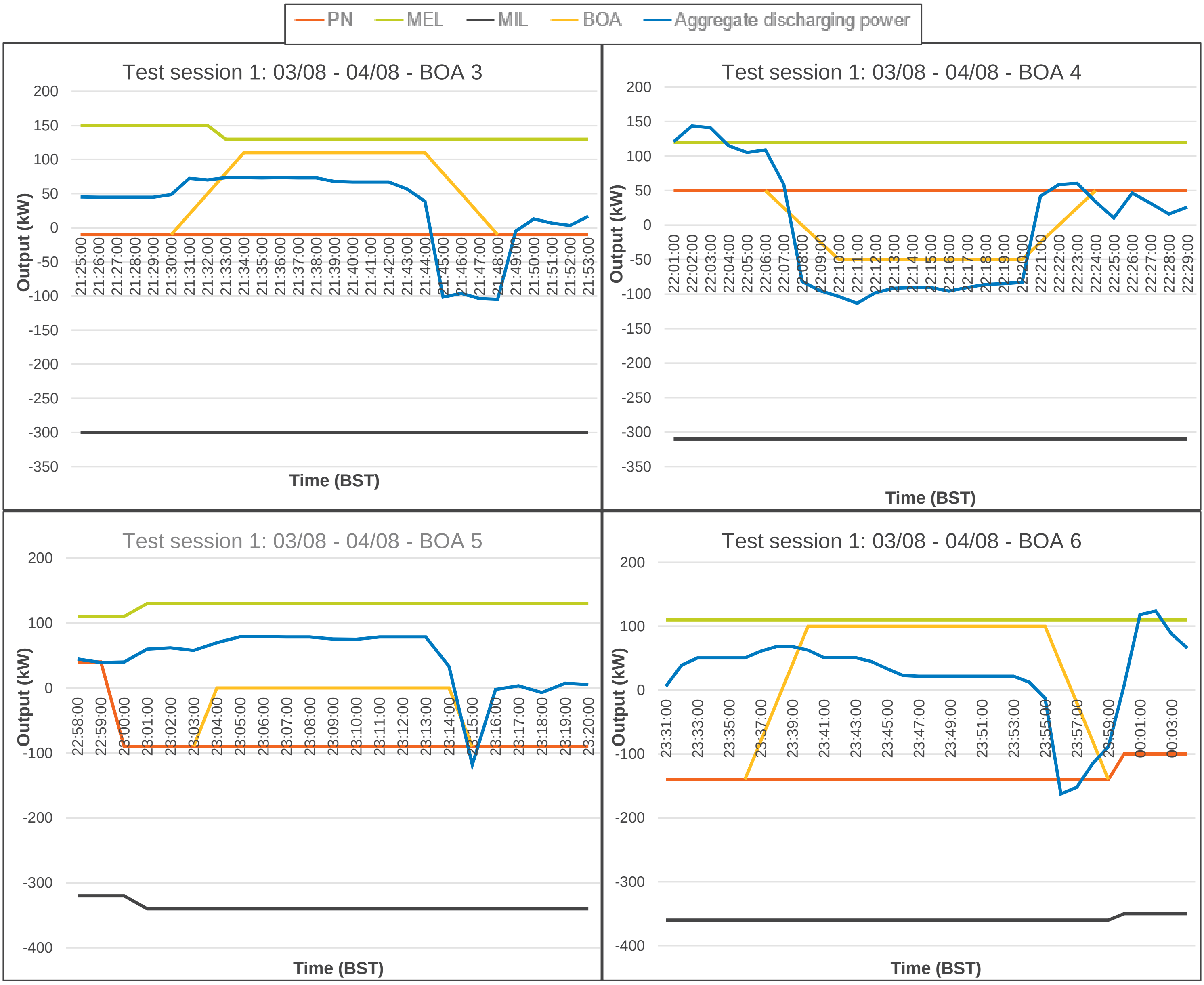
Pictures 1 & 2 below show how the trial BMU responded to each instruction that was sent across the trial sessions.

Picture 1 shows how the aggregated unit responded to instructions sent from the ENCC engineer across the first trial session. For the first two BOAs the instructions from the ENCC were not converted into updated (dis)charge schedules for the vehicles due to communication issues in the trial setup, hence there was no response seen in the metering feed. As this was not representative of the actual capability of the assets, we have focused our analysis on the instructions that were converted into updated schedules. As can be seen there is a mixed response to the instructions, with indications of the right behaviour in most of the scenarios however not the complete response expected. In most cases the activity of the asset alters correctly at either the start or end of the instruction, however it is not consistent for both ends of the instruction other than in BOAs 3 & 4. Although the magnitude and speed of response are not a perfect match, both show the desired shape and BOA 4 shows the ability of the unit to return to its PN following the instruction.

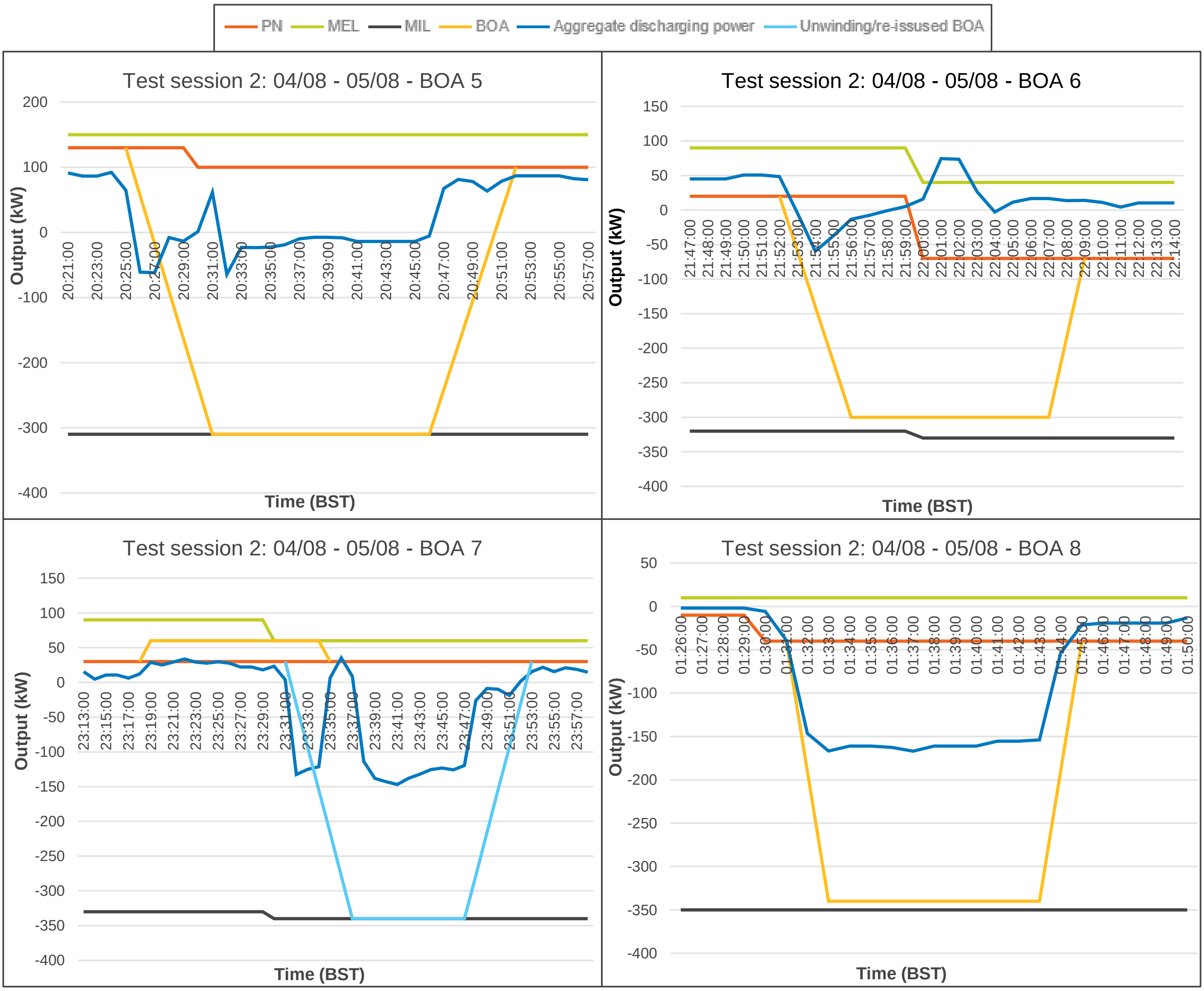
Like the first trial session, the first few BOAs in the second session weren't converted into updated (dis)charge schedules for the vehicles due to communications issues in the trial setup, therefore we will only focus on BOAs that were converted into updated schedules. Picture 2 show improvements in the responses from the aggregated unit in the second session, both in comparison to picture 1 from the first night and progression through the night. This is evidenced most clearly in in BOA's 5, 7 & 8. The ability to change behaviour of the fleet at the exact timing required by the ENCC is clear, with the final BOA showing a shape that matches the instruction nearly perfectly. For BOAs 5 & 7 there were some issues with maintaining the response during the instruction. All three struggle to meet the desired magnitude of response in the instruction; as all were bids to or close to the MIL, this implies that the MIL was set too low.

The ability of the fleet to accurately respond to BM instructions was variable but showed clear improvement over the course of the trial. The fleet optimiser system was improved over the course of the events, and it is encouraging that the response behaviour improved accordingly. The final BOA response demonstrated near perfect characteristics after correcting for an inaccurate MIL value. These results suggest that a unit comprised of aggregated V2G EVs should be able to provide necessary response behaviour in the BM but is likely to require careful management.

Picture 1 – Breakdown of responses to individual instructions sent during the first test session



Picture 2 – Breakdown of responses to individual instructions sent during the second test session



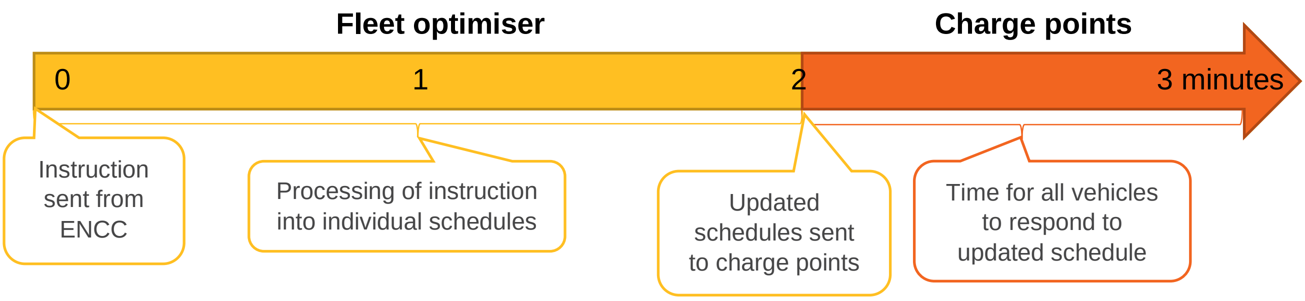
Response times

An important finding from the trial was gaining understanding around the speed at which the vehicles would respond to instructions from ENCC. This provides valuable leanings for how EVs would interact with the BM and provides evidence to how they could participate in other markets. While EVs can theoretically ramp up their output very quickly (typically within seconds), an important parameter for the ENCC to understand is the total time it takes for the fleet to respond to a signal. This will include communications delays from the ENCC to the fleet optimiser and in turn to each individual vehicle. In real operation, the response time would be communicated via the ramp rate and NDO/B parameters. To investigate this during the trial, these parameters was set to its maximum value and the response time observed.

Signals received from the ENCC had a minimum delay between receipt and action (I.e., the time at which the fleet was expected to reach its setpoint) of 3 minutes. The fleet was able to respond within this timeframe across all test events. In addition, updates to schedules of individual vehicles, to meet this setpoint requirement, were actioned in less than one minute. Below details the timeline of events.

Although not assessed through the trial, it is expected that the time from receiving an instruction to response of all vehicles can be less than 3 minutes. Further testing is required to show this in practise and understand the processing time required by the fleet optimiser to convert the instruction into individual vehicle schedules.

It should be noted, however, as mentioned previously that the BM rules do not *dictate* a full response time; in fact, many current participants respond significantly slower than this.



Key insight - Operational metering

Using post event analysis, the trial was able to compare the expected activity of the fleet against actual active power measurements from the fleet. By taking individual active power measurements from the charge points, which were available at a frequency of every 10 seconds, it was possible to create a second-by-second metering feed of the aggregated unit. This meets the current requirements for the BM for read frequency. This will have at most a ten second lag on an individual device basis but would be acceptable at the aggregate level because the individual device readings are updated asynchronously; resulting in an aggregate feed that can change at each (1 Hz) update. Although this does not meet the current standards for operational metering required to enter the BM (due to accuracy and latency standards), the trial has shown an effective aggregation methodology utilising the metering capability typically available for EV charging assets being installed today. Further work is required to prove the accuracy of methodologies such as these when compared against the current requirements. Ensuring that standards are applied proportionately for small-scale assets within aggregated portfolios whilst maintaining an appropriate accuracy for economic and secure energy balancing activities.

Key insight – Commercial viability

Commercial parameters - Bids/Offers

Understanding whether the unit used in the trial could offer a cheaper option to meet energy imbalances for the ENCC was crucial to proving the viability of EV's entering the BM. To that end, realistic prices were used, and the fleet was only dispatched when these prices were found to be competitive with the true market. A simple pricing strategy was used, but the result that the fleet was dispatched when compared to the market indicates that domestic EVs participating in the BM could help reduce overall balancing costs. This would return value to households participating in the BM and would, in addition, result in a cost reduction for *all* consumers of electricity from a balancing cost reduction. Table 3 highlights the bid/offer price taken by the ENCC engineer during the second trial session compared to the least attractive bids/offers taken in the live market for the given settlement period. There were issues with the submission of bid/offer prices across the first trial session which were amended for the second, therefore this chapter will focus only on this second session.

Data for the least attractive prices taken in the live market were taken from our dispatch transparency set, we have excluded any actions that were taken for 'system' reasons to focus entirely on energy balancing activities. For a couple of BOAs it was difficult to retrospectively compare instructions sent to the trial BMU against actions taken in the live market, this is due to actions in live operations often meeting system and energy requirements and therefore not being visible in the dataset.

Table 3 shows that for each BOA taken, the trial BMU had a more favourable price than the least attractive actions taken for energy balancing reasons. This is indicated by bid prices being more expensive (as money flows from provider to market) than the comparable action in the live market, with offer prices being cheaper (as money flows the opposite direction). Although comparing the two data sets does not guarantee the trial BMU would have been dispatched in live market operation (many situational considerations are continually being reviewed by ENCC engineers), it is a strong indication that the unit would have been a favourable option.

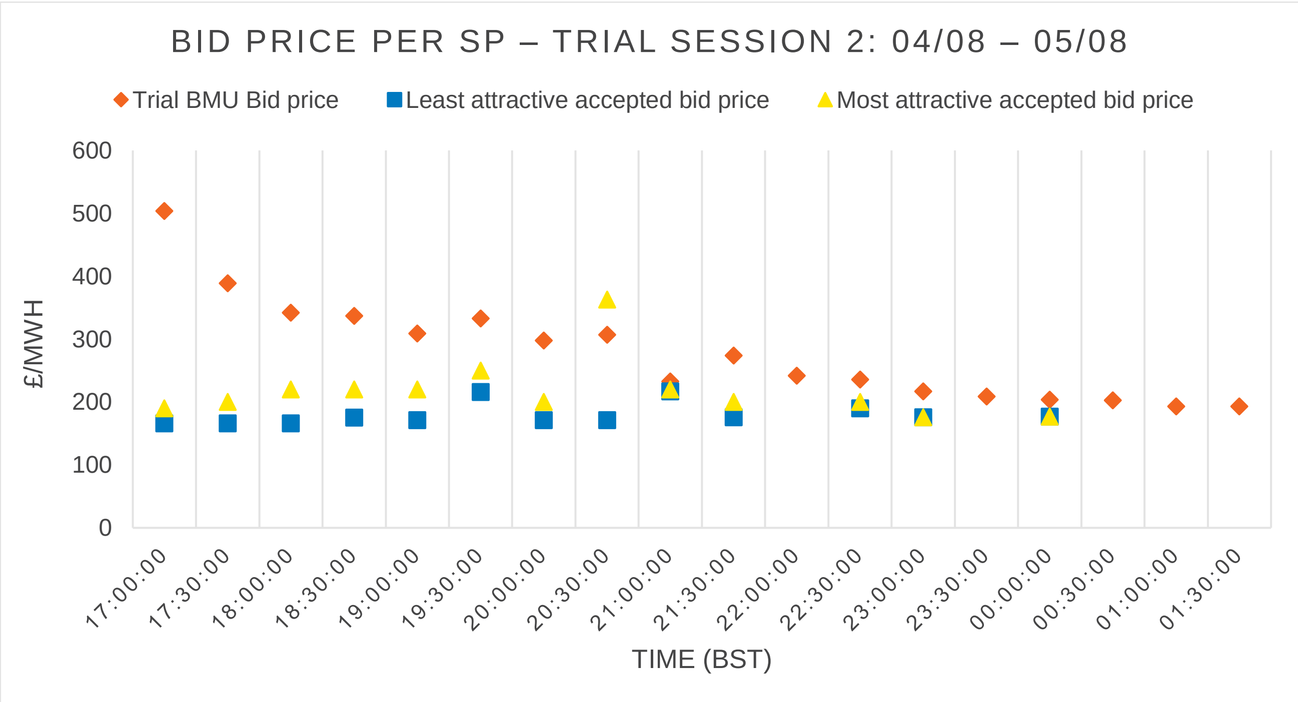
Table 3 – Price comparison between the trial BMU price and the least attractive accepted actions taken in the live market, for each period an action was taken in the second trial session.

BOA	Settlement period start time (BST)	Action taken	Trial BMU price (£/MWh)	Least attractive price accepted in BM for energy balancing during settlement period (£/MWh)
1	18:00	Bid	592	166
2	18:30	Bid	604	175.11
3	19:30	Bid	442	216.08
4	20:00	Offer	337	Not available
5	20:00	Bid	437	171.05
6	21:30	Bid	398	176
7	23:00	Offer	274	331.71
8	01:30	Bid	304	Not available

Graph 3 below shows the bid prices submitted by the market participant across trial session two, against the least attractive and most attractive bids taken in the live market, again focusing only on actions taken to meet energy imbalances. Where there are gaps for the least/most attractive accepted bid prices, this indicates that actions taken by the ENCC were either difficult to attribute purely to energy imbalances, or no actions were taken in this direction.

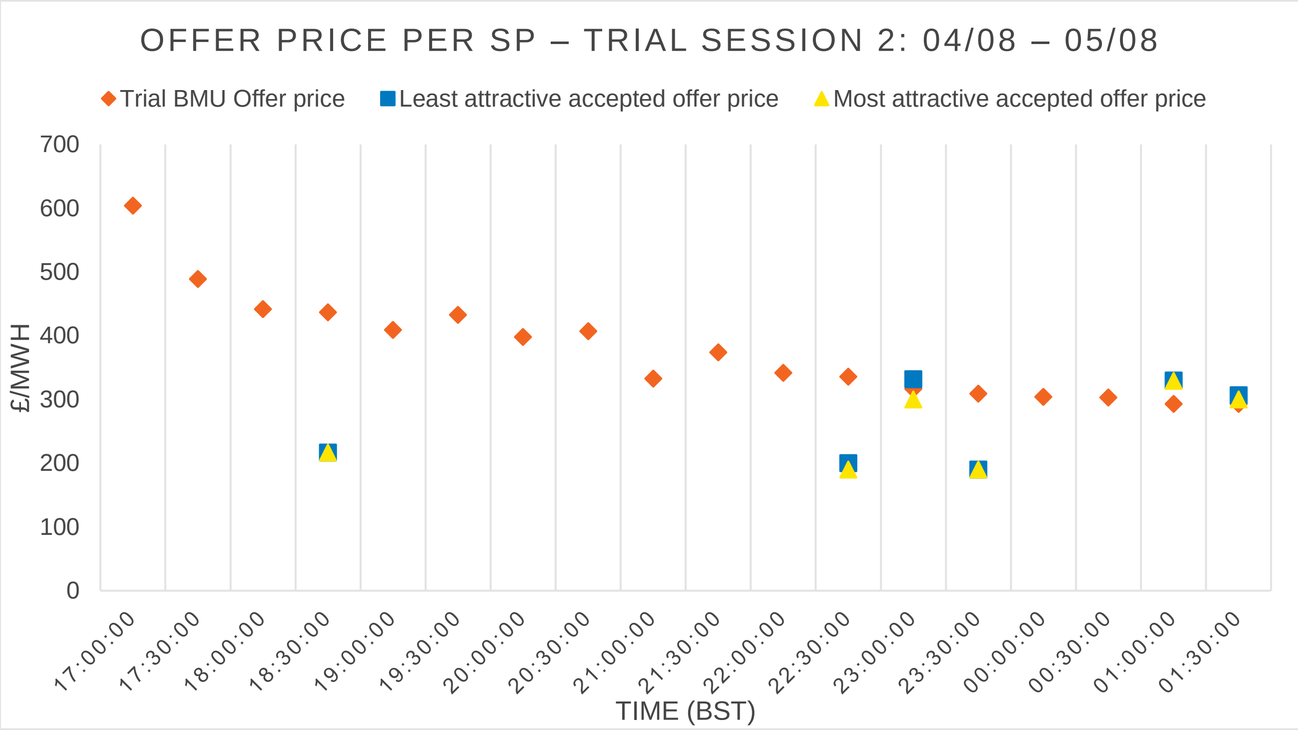
For the eleven settlement periods that the ENCC were accepting bids to meet energy imbalances, the trial BMU would have been a more attractive option (higher price) for nine of these periods than the least attractive bids that were taken. This suggests that in addition to the periods highlighted in table 3, the trial BMU would have been a more favourable option to ENCC engineers for most periods across the trial session, when compared against the actions taken in the live market. In addition to this, for eight of those nine periods the unit would have even been more attractive than the cheapest action taken in the live market, suggesting the trial BMU would have been the most attractive option to ENCC engineers during these periods.

Graph 3 – Bid price comparison between the trial BMU and live market actions taken, for all periods in trial session 2



Graph 4 shows the same comparison as graph 3 but for offer prices. With only six periods where offers were accepted to meet purely energy imbalances by the ENCC, it is difficult to draw any conclusions around instructions sent to increase the exporting (or decrease the importing) from the aggregated unit being a more cost-effective solution than the live market. However, as three of these periods show the trial BMU to be a more attractive alternative (cheaper) than the least attractive offer price accepted, it would suggest there are still benefits to system costs like those shown in graph 3.

Graph 4 – Offer price comparison between the trial BMU and live market actions taken, for all periods in trial session 2



It should be noted that the bid/offer pricing strategy used did not consider how energy imbalances, following instructions from the ENCC, would be recovered by the provider in future settlement periods to ensure the updated charge schedules of the vehicles are accounted for. Nonetheless, these results indicate the promise of a cheaper and greener alternative for the ENCC to meet energy imbalances through balancing activities.

Pricing strategy – End consumer

A key objective for the trial was to investigate whether financial benefits could be realised for end consumers by participating in the BM. The customer proposition trialled in the Powerloop project was to offer peak and off-peak rates for import and export, allowing customers to benefit from wholesale arbitrage. In addition, these rates were set at better-than-market values to pass on more of the savings to the end customers, with the off-peak charging/peak discharging periods extended whenever charging/discharging was scheduled by the Kraken optimiser. It was intended that this mechanism would be used to pass on revenues derived from the BM as well as wholesale benefits. Octopus Energy reported customers participating in the Powerloop V2G trial realised a saving of up to £180/y compared to smart charging on a time of use tariff derived from wholesale prices, or £840/y compared to unmanaged charging on a flat tariff, when adjusted to an annual mileage of 10,000 miles.

Viability of entry into the BM

The BM has a framework that is dictated by a combination of code obligations, predominantly the Grid Code and BSC (other codes are applicable). Providers wishing to enter the market need to meet code obligations which apply to them, they will also need to agree to a bilateral agreement with the ESO (in the case of VLP's this will be a VLP agreement). This ensures the safe and efficient management of the electricity system, whilst ensuring the most economic actions are taken to balance the energy system in real-time.

Through the trial we have been able to highlight areas of these code documents, bilateral agreements and overall market framework that could act as a potential barrier for aggregated EVs entering the market. Most are seen as barriers that will organically become less of an issue over time, as we continue to see the growth and adoption of EVs. However, operational metering requirements to participate in the BM currently act as a key blocker for this type of asset. There is a clear gap between the current standards and the metering capability of assets being manufactured and installed today, a Power Responsive working group is addressing this[23].

BM framework requirements

Several elements of the BM framework are dictated by ESO and will be detailed in bilateral agreements with providers. These are fundamental to ensuring we have the right information, tools, and processes to effectively balance the system. The areas highlighted below are aspects of the BM framework that are a current requirement on providers entering the market that pose a potential barrier for modern technologies such as EVs.

Operational Metering

From discussions with suppliers, aggregators, charge point manufacturers and installers, the ESO understands that there is a wide range of metering capabilities associated with EVs and charge points. These range both in terms of the accuracy of the measurement taken and the frequency with which a measurement is taken. During the trial, the metering at an individual charge point was able to take an active power measurement (in kW) every 10 seconds at a quoted accuracy of +/- 8%. Surveys conducted by Power Responsive suggest that some charge points have better metering capabilities than the ones used in the trial, as well as charge points that have limited or no existent metering facilities.

In June 2022, the Electric Vehicles (Smart Charge Points) Regulations[24] came into force for all new installations of smart charging devices. These regulations stipulate that manufactures and installers must ensure that any relevant charge point must be capable of measuring or calculating, every one second, the electrical power it has imported or exported (in kW or W) whilst in use. This measurement must be accurate to within 10% of the true value and any inaccuracies must not be systemic. This goes some way to bridging the gap between current obligations around metering requirements to enter the BM (see earlier sections) and the capability of the charge points being installed today, however there are clearly still large discrepancies especially around the accuracy requirements of readings.

Also of relevance, Elexon have recently introduced a new code modification (P375[25]) which will allow VLP's to settle their balancing actions based on asset level metering from behind the boundary meter point. This is a big step in opening balancing markets to aggregators and will hopefully pave the way for greater participation and more accurate settlement processes. For aggregators to utilise P375, the asset level metering must meet the new of Code of Practise 11[26] standards, developed by Elexon in conjunction with the modification. The limits on accuracy for settlement metering are much tighter than the smart charge point regulations, however they are still less stringent than current BM operational metering standards.

As detailed in table 2 earlier in the report, we stipulate metering standards that are required to enter the BM in bilateral agreements with providers. These are based on ECC requirements and parameters that will ensure the safe and economic balancing of the system.

With three different standards currently in place of varying requirements there is work to be done to align these, ensuring that manufacturers are creating facilities that are equipped to meet the requirements of our markets as well as ensuring flexibility from assets currently installed can enter ESO markets. The ESO see this as the main blocker for entry for many new technology types looking to enter ESO markets. A working group as part of Power Responsive has been set up looking to enforce proportionate metering requirements for small-scale aggregated assets. This will focus on the accuracy and refresh rates discussed above, unlocking flexibility that is currently available across the country without impacting ENCC operations. Alongside this, a review into requirements on measurements, such as Reactive Power, which are not always readily available from charge point facilities needs to be undertaken by the ESO.

[23] https://www.nationalgrideso.com/industry-information/balancing-services/power-responsive#Working-groups
[24] https://www.legislation.gov.uk/ukdsi/2021/9780348228434/contents
[25] https://www.elexon.co.uk/mod-proposal/p375/
[26] https://www.elexon.co.uk/article/new-bsc-code-of-practice-cop11-sets-standards-for-accuracy-of-asset-metering-systems/

Individual asset level data burden

As part of the registration process to become a BMU, a VLP must provide a large amount of information for each asset that makes up each aggregated unit. This information feeds into network modelling and planning processes completed by the ESO to assess constraints and impacts of new units entering the BM. Typically, aggregated units have consisted of a small number of large units, so that modelling their impacts on system operations was essential to the ESO and processing of the data through the registration was manageable for both parties.

As we look towards incorporating aggregated units comprised of many small assets, 7kW in our trial for example, the ability to model these assets accurately and efficiently needs to be considered. The increase in the volume of information from the increased number of individual assets is something we will need to consider. It will place extra strain on registration and modelling systems as well as resourcing of teams that operate these and therefore needs to be balanced against data accuracy.

From a participant's point of the view, the volume of data that needs to be gathered is significant due to the number of individual assets they will be registering. In certain cases, obtaining this data could prove problematic, especially if aggregators are acting on behalf of other providers who do not provide the required granularity of data by default.

Although this is not considered a prohibitive barrier to entering the BM, it can slow down the registration process and is an area that could be potentially improved through more targeted requirements for modelling processes from the ESO.

Code obligations

Most of the requirements for providers looking to participate in the BM will be captured in Grid Code and BSC obligations. The areas below highlight obligations that could be seen as a barrier to enter the BM for providers looking to access the market with smaller-scale aggregated assets such as EVs.

Balancing and Settlement code

Minimum threshold and location aggregation

Providers wishing to register a new aggregated BMU must ensure all assets that make up the unit are within the same GSP group, this is detailed in Section K 3.3.7 of the BSC. All settlement processes Elexon perform are based on GSP group aggregation, therefore this is unlikely to change soon. For participation in most of our markets (BM included) we also require aggregation at a GSP group level when grouping assets into a single unit. Understanding geographical location of units is vital for the ENCC to forecast and understand the impacts of dispatching certain units, typically in relation to managing constraints.

The current Balancing Mechanism framework stipulates a minimum threshold of 1 MW for units to enter the market, with aggregated units only able to span a single GSP group, although there is no minimum size requirement at the individual asset level. While the EV market is in its infancy, finding enough vehicles to reach the 1 MW threshold in a single region of the country could provide a barrier to participants entering the BM. Assuming a 7 kW charger power rating (a fair representation of a typical home EV charge point being installed across the market today), at least 150 vehicles would be needed to meet the minimum threshold capacity of 1 MW. In practise many more vehicles would be required, given the stochastic nature of availability. Although this presents a barrier today, it is the expectation that with the forecasted growth of EVs that this will not be a sustained issue for one-directional smart charging. With V2G enabled assets at a much earlier stage of growth, this barrier will remain for longer.

Whole integer requirement for data submissions

Section Q 3.2.3 of the BSC outlines that PNs are to be expressed as whole MW values. As data feeds from ESO to Elexon for settlement purposes, the current systems used to schedule and dispatch assets in the ENCC are limited to whole MW granularity. The Balancing Programme is developing new infrastructure that will overcome this and facilitate sub-1 MW data submissions and dispatching; however this is not due to be operational until 2025 according to the current roadmap[27]. Details on how this will be implemented for settlement purposes are yet to be worked through.

[27] https://www.nationalgrideso.com/what-we-do/electricity-national-control-centre/balancing-programme

Due to this restriction, even if a provider were able to get 150 vehicles available at any one time, the range of responses available would be limited to whole integers (e.g. -1 MW or 1 MW for a V2G enabled unit), with little scope to build in variation for the vehicles' SoC/energy available.

Whilst this is not a barrier beyond the minimum threshold requirements, it does limit the capability of this asset type and does not maximise the flexible potential that EVs could offer.

Grid code

System telephony and Facsimile Machine

Like operational metering, as part of the bilateral agreement with the ESO, providers that have a cumulative capacity (as judged from the control point) of less than 50 MW across all their BMUs are required to install System Telephony (> 50 MW would require Control Telephony). This is to ensure that the ENCC can communicate with provider for safety, operational or data related issues. Currently bilateral agreements state it must be possible to have immediate and direct contact with the provider's control point, 24 hours a day, 7 days a week. Similarly Grid Code CC 6.5.9 states a provider must have installed a Facsimile (Fax) Machine.

Requirements for participants to install system telephony are unlikely to be removed in the short term, as having direct and immediate contact with providers is still essential for events such as a loss of primary communication channels. The role of fax machines in system operations is being reviewed and the hope is to remove any reliance the ENCC currently have on this technology over the coming years.

Whilst the installation of System Telephony or a fax machine is not seen as a prohibitive barrier, always having resource available 24/7 could be seen as a financial burden on newer providers who are not currently operating at all hours.

Aggregator impact matrix

Providers operating an aggregated asset in the BM are required to submit an Aggregator Impact Matrix (AIM) at 11:00am each day for the following day, as per Grid Code BC 1.A.10.1 This details the effect of a Bid-Offer acceptance on each Grid Supply Point within the GSP group over which the BMU is defined. See table 2 below for an example. When utilising behind-the-meter assets, in particular within domestic properties, being able to accurately detail where the response to instructions will show up for the following 24 hours is difficult for providers. As these assets have a reliance on human behaviour it makes their consumption patterns more difficult to predict, leaving them much more exposed to intraday changes which are not supported in the current framework. Whilst there are no direct financial penalties for not matching their AIM, providers risk breaching code obligations if they are deemed to not be taking all reasonable measures to ensure they accurately meet this requirement.

Whilst this is an understandable request for accurate modelling and visibility of power flows on the network following instruction from the ENCC, the smaller the unit size the less impact on the network and therefore the accuracy of this matrix should be relative to this. Careful consideration is needed for how to implement the AIM for smaller-scale assets such as EV's, accuracy of the information stored in these matrices will be vital when you consider the aggregated volumes of EV charging we are expecting to see on the network.

<table>
<tr><td colspan="4">BMU Name</td></tr>
<tr><td colspan="4">Operational Day from which values apply</td></tr>
<tr><td>Grid Supply Point</td><td>% Impact</td><td>Grid Supply Point</td><td>% Impact</td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
<tr><td></td><td></td><td></td><td></td></tr>
</table>

Table 2 – Example of Aggregator Impact Matrix that needs to be submitted daily at 11:00

Conclusions

Capability of aggregating V2G enabled EVs

The trial has highlighted the ability of EVs acting as an aggregated unit to meet many of the requirements of the BM when it comes to data parameters and response to instructions. There was also a clear improvement across the two nights as the teams were able to build in learnings throughout the sessions. The results highlight aspects that require refinement, these are summarised below.

When considering accuracy of data submissions, this refinement can be worked on by providers, building on the leanings from this trial and recognising the requirements that need to be met to enter the BM. Understanding the reliability of assets is an important next step to build confidence in this asset type for energy balancing activities, this will need to be considered with larger volumes of vehicles across multiple providers. Although larger aggregations may increase the variability between individual assets, it should bring improvements to the overall aggregated accuracy as the impact of an individual asset is reduced.

Operational parameters

Physical notifications

As the graphs 2 and 3 suggest, further work is required to ensure aggregated charging schedules meet the physical notifications both before and after instructions. Increasing understanding of consumers' behaviour will help providers ensure their forecasts are accurate and, as mentioned previously, functionality to adjust (dis)charging actions to match PNs could be added. It is also worth noting that the accuracy of prediction of aggregate fleet behaviour is expected to improve with fleet size. In addition, providers need to carefully consider the impacts of instructions from the ENCC on their charge schedules, ensuring that following a response to an action the fleet can return to its forecasted PN, bearing in mind that they can only alter this up to 60 minutes ahead of real time. Failing to do so causes difficulties for the ENCC as demand forecasts are based on this data; it could also impact providers in settlement charges.

As this is a duration limited asset class (i.e. there is a limit on how long it can respond to instructions for), a key factor in ensuring the PN accurately reflects what the fleet can do is the length of instruction they can expect to receive from the ENCC. Currently the principle followed with storage providers is that they will only receive a maximum 15-minute instruction, with the expectation that providers set their dynamic parameters accordingly. It is the expectation that this principle would be extended to EVs also, however it is the hope that in the future dynamic parameters will better reflect the capabilities of storage units. There are ongoing conversations around what these future data parameters could be, including a storage stakeholder group led by the ESO Balancing Programme[28]. The outcomes of this work will help the ESO better understand and use duration limited assets, improving the ability to automate instructions to these assets with confidence over delivery.

Maximum Export and Import limits

Like PNs, further work is required to ensure the maximum/minimum capabilities of the assets are set accurately. Although the parameters were used slightly different to how they would be in live market operations, the trial still highlighted inaccuracies in MIL/MEL setting. Being unable to reach maximum import/export limits when instructed to do so by the ENCC has impacts on system operations, but also on the provider in settlement processes.

It is suggested that providers take the learning from the trial and effectively set the maximum import/export limits, as well as setting effective tranches for their bid/offer pricing. Individual customer's charging preferences is a priority for providers looking to utilise this flexible resource, therefore the setting of these limits and prices is fundamental to ensure no impact on end consumers' lives, whilst also avoiding penalisation in settlement calculations.

The trial included MIL/MEL adjustments based on recovery actions to BM instructions but, again, the accuracy of this would need improving. No prediction of customer plug/unplug was considered, which would be necessary in real operation; although it should be noted that large portfolios will smooth this effect across individual components.

[28] https://www.nationalgrideso.com/what-we-do/electricity-national-control-centre/balancing-programme

Response times

The trial showed a clear timeframe within which an aggregated asset of this type can respond comfortably, with suggestions this could be improved below 3 minutes. Specifically, further work could focus on whether the 2-minute processing window highlighted could be reduced, although the BM framework does not dictate the response time that assets must achieve. In live market operations, this processing time would need to be factored into the market participant's dynamic parameter submissions, either through the Notice to Deliver Offer/Bid or Run-up/Down rates depending on how consistent the processing time was across the entire fleet of vehicles.

In most scenarios in the BM a faster response rate is preferred, however it is worth noting that by staggering the updated schedules being sent to the individual vehicles, the aggregated unit can meet any required ramp rate from the ENCC that was slower than their capabilities. This could be either set through ramp rate parameters by the market provider, or more likely dictated by the shape of an instruction sent from the ENCC. This staggering process was not assessed directly during the trial process and is a suggestion for further work.

Commercial viability

Pricing Structure – Bids/Offers

The pricing structure used by the market participant in the trial focused on the day ahead wholesale prices, intending to reflect the value of the BM to end consumers above what can already be achieved via arbitrage in the day ahead wholesale market. In live operations, consideration is needed for how instructions from the ENCC will alter the charging schedules of individual vehicles, creating future imbalances that would either need to be recovered by participants through within-day trading or via imbalance charges. Further work is required to review the impacts of this on how a provider would price their bids/offers, comparing this against market competitors to ensure it would still be an attractive price to meet energy imbalances for the ENCC. However, this sits firmly within market providers' remits and need not be tested ahead of genuine market entry.

Pricing Structure – End consumer

The static time-of-use tariffs used in the trial sessions reflected (smoothed) wholesale prices, incentivising a shift of demand into regions of low price and exporting in times of high price. This has proven an effective approach in altering (dis)charge schedules of the vehicles and making it simple to process for consumers as they are only working with two different prices across two separate time frames. It is the responsibility of the market provider to convert the complexity of participating in the BM, alongside wholesale markets, into understandable customer propositions.

Viability of entry into the BM

Although barriers in the current BM framework have been highlighted through the trial, most should be organically overcome with increased adoption of V2G and EV technology across GB. The key outstanding barrier from an ESO perspective is operational metering, as it is clear there is a discrepancy between the current metering standards for the BM and the standard of metering being installed at charge points today. The Power Responsive working group is focusing solely on overcoming this barrier, to ensure that operational metering standards are applied proportionately for small-scale assets within aggregated portfolios.

It is a requirement for domestic properties to be HH settled if they are to be included in a unit that offers balancing services to the ESO via the BM. This is a current barrier to entry for independent aggregators, who don't have the ability to alter how a property is settled, and suppliers who don't currently have the capability to facilitate HH settlement. If market framework barriers are overcome this settlement requirement could still limit the amount of flexible assets available to the ESO for balancing services in the BM. MHHS will ensure domestic properties will be HH settled by default, therefore removing this barrier.

In addition to the learnings detailed in the report, the trial has highlighted system, process and resourcing impacts related to a significant increase in aggregated assets, such as dispatching aggregated assets near a constraint and modelling domestic assets spanning an entire GSP group. These are being worked through by the relevant teams across the ESO to ensure that we will be able to manage increased numbers of aggregated assets entering the BM, ensuring economic dispatching and accurate modelling in our systems.

Next Steps

There are several different workstreams across the ESO working concurrently with this trial, assessing the capability and suitable of EV charging (in its various forms) to our markets, processes and systems. The report has highlighted areas of review and refinement before this resource is ready to play a role in energy balancing activities. These will be reviewed and considered across the business, not just in relation to entry into the BM but also the role these assets could play across our other markets. We intend to continue to collaborate with providers in the space, collaborating through the workstreams mentioned below to understand how to best utilise these assets moving forward as the potential benefit to balancing activities increases significantly.

- **Power Responsive** – Power Responsive is a stakeholder-led programme, facilitated by the ESO, to stimulate increased participation in the different forms of flexible technology such as demand side response and storage. As the report has mentioned, a working group has been set up to review the operational metering standards in the BM, ensuring they are applied proportionately for small-scale assets within aggregated portfolios. The stakeholders across this group will continue to engage on the areas of review and refinement highlighted in this report, working collaboratively to overcome barriers and unlock this growing resource for energy balancing activities.
- **CrowdFlex** – The CrowdFlex project is being delivered by a consortium of companies from across the energy sector and is funded through Ofgem's Strategic Innovation Fund. It is exploring how domestic flexibility can be used in grid operations to help align demand to generation, improve coordination across the network, reduce stress on the system, while empowering consumers to be active players in reducing their energy bills via new tariffs and incentives. The next phase of the project will examine the use of availability payments to encourage users to plug in their EVs and make their heat pumps and other fully automated devices available for use in post-gate closure services such as the BM. Trials in this phase will aim to test the price sensitivity of encouraging owners to make their vehicles available more frequently for use in balancing actions by offering them a range of different pre-payments.