From: [redacted]
To: Cleve Hill Solar Park
Subject: Additional Evidence
Date: 30 August 2019 16:29:42
Attachments: [redacted]

From CHRIS LOWE Interested Party, reference: 20022096

Dear Examiners,

Below is some more additional evidence for the Examination, which I hope is helpful to you.

Best wishes,

Chris

Collated References which are referred to below

1 The Changing Electrical System: Demand Side Response, Flexibilty & other aspects
In my Written Representation, I referred to flexibility and demand side response and quoted some example, such as REF 5, Riello UPS & RWE, and I now provide further evidence on these aspects.

These varied resources are cheaper, more flexible, have lower transmission losses, and provide more benefits, especially to local people, than the Applicant's proposals.

1 A Demand Side Response (DSR): Uninterruptible Power Supplies as a Reserve
Data centres need to have 24 hour availability of power, so they invariably have uninterruptible power supplies (UPS).
These are expensive, and are only used occasionally so at least one company, Eaton, have developed a product which enable data centre UPS to operate as a Demand Side Response (DSR).
See Attachment above (**1 A Demand Side Response (DSR): Uninterruptible Power Supplies as a Reserve** Electrical evidence August.rtf) for source document.
They have already trialled their UPS-as-a-Reserve (UPSaaR) product and have shown that this can be done without affecting the UPS role.
Hence this enables lower-cost DSR, because data centres must have UPS, so any income is icing on the cake, as it were, so they can charge much less than say a battery on grid such as the Applicant proposes, as the battery is not essential for the solar power station.
Furthermore the UPSaaR has 24 hour availability, not being reliant of recharge from the solar farm, as the Applicant's proposal would be.

1 B Demand Side Response: Incentivising Domestic Demand Response
Although the National Grid is focussed on large generators and users, the total domestic electricity market is very large, so that enabling such users to provide DSR has the potential to yield huge benefits for the stability of the distribution networks, reduced costs to consumers and distribution network operators.
The attached, above (**1 B Demand Side Response: Incentivising Domestic Demand Response** Electrical evidence August.rtf) shows how GenGame (www.gengame.co.uk) is using its trial with Northern Powergrid and its gaming expertise to bring together Electric vehicles, solar photovoltaics (PV) on users' roofs, and domestic battery storage to provide infomation to users so that they can maximise use of their PV power and shift energy consumption and provide DSR. The scheme also includes joining with Ecotricity for Electric vehicle to grid operation.
This enables non-technical users receive benefits from flexibility without needing technical knowledge.
This also means that more houses will find it worth installing PV, further reducing any need for large solar power stations on unsuitable land, such as the Applicant's proposal.

1 C Demand Side Response: Incentivising Commercial Demand Response
Similar activity is taking place for commercial users, such as the scheme from Grid Edge.
The first paragraph of the attached reference (**1 C Demand Side Response: Incentivising Commercial Demand Response** Electrical evidence August.rtf) provides the reason and benefits of this approach:

“It’s our view that the fundamental issue is that the grid support required for technology like EVs or heat pumps has always been done on the grid side’s terms; it’s never really been done on a customer’s terms.

All of our customers have really ambitious carbon targets and have their neck on the line about it... And I think their view is that they’re being let down a little bit by the industry.

There's been very little active communication between consumers and their supply side partners and those relationships have been built around procurement and billing. I do think both DNOs and suppliers have been trying to change this recently as suppliers look more towards service focused offerings and DNOs are trying to become more consumer centric.
What we’re doing at Grid Edge is building the tools to help building operators engage with the future energy system. We think that system will be dominated not by how many kWh you use or generate but by when you consume or generate. We want our customers to be ready to proactively address that opportunity.”.

These comments about the National Grid are reinforced by the National Grid Electricity Transmission (NGET) draft of its RIIO-T2 business plan, whereby its current annual costs of £1.2 billion would increase to £1.5 bn, and that does not reflect the Government’s recently adopted Net Zero, which would increase NGET’s costs if more renewables, such as the Applicant’s large solar power station were connected to it. (see: www.current-news.co.uk/news/national-grid-electricity-transmission-unveils-7-4-billion-plan-to-build-transmission-system-of-the-future).

I know from my own experience managing the utilities for a Kent & Canterbury Hospital twenty years ago, that we had interruptible gas supplies which provided much cheaper gas Unfortunately we did not have that flexibility from the electricity supplier, even though we had to have emergency generators, which were very rarely used, but had to be regularly tested on load, causing us extra work and some disruption to the hospital as not all sockets were supplied by these generators.
So it would have been very beneficial to have been able to benefit from DSR.

1 D Reducing energy costs or increasing earnings for local generators and consumers.
The report in attached (**1 D Reducing energy costs or increasing earnings for local generators** Electrical evidence August.rtf) was written with regard to reducing costs and increasing earnings for distributed energy resources (DER) which further incentivise the installation of local renewable schemes supplying the immediate locality.
Although this was a trial, and would need removal of Ofgem’s unnecessary restrictions on multiple energy suppliers, it shows what is in the pipeline, and also that costs are lower and benefits greater if the renewable resource is as close as possible to the consumer, rather than a huge scheme feeding the Grid which cannot supply local consumers because the grid connection being used has no connection to the local distribution network.

1 E New partnership for flexibility

Flextricity, as might be expected from its name has partnered with eight organisations on a new trial which it says holds the potential to “revolutionise the demand side response industry”. They already have 500 MW flexible assets and they say:

“Flexible energy use is a vital part of a greener energy system, balancing variable renewable generation and growing demand as heat and transport are electrified. Flexitricity’s mission is to make this feasible and economically attractive for all types of energy user."

(See: **1 E New partnership for flexibility Flextricity** Electrical evidence August.rtf)

The rapidly changing energy scene is shown in the report attached (**1 E New partnership for flexibility Kaluza Sonnen partnership** Electrical evidence August.rtf), whereby energy technology firm Kaluza and battery storage manufacturer Sonnen have entered into a new partnership to introduce new flexibility onto the UK’s grid.

This will enable the one million Shell energy customers and many others to participate in the energy market, showing the further rapid shift in this market.

1 F Improving the Networks for flexibility

The network companies who are members of the Energy Networks Association are pushing ahead with flexibility, as part of its Open Networks Project, with new proposals within a consultation on application interactivity and connection queue management which outlines plans to make it easier for more flexible energy projects to connect to the grid.
The ENA say: "The Open Networks Project is leading the way on our much needed transition to the smart grid, looking at ways we can speed up connections, encourage new flexible energy markets and deliver Net Zero."
See: www.current-news.co.uk/news/flexible-energy-projects-could-jump-connection-queues-under-network-modernisation-plans

1 G UK Power Networks Flexibility Contracts
The next section on Community Energy, and the Community Energy Hub website (https://hub.communityenergyengland.org/) refers to the research on flexibility potential for the UK, and the report (attached) and available on:
https://carbon.coop/2019/01/local-flexibility-markets-what-are-they-and-how-can-community-energy-organisations-get-involved/
shows research across the country.

In my Written Representation, in REF 6, I referred to our local DSO/DNO, UK Power Networks flexibility auction of 2017, and now on page 38 of the main technical report (attached) this is updated:
"The consultation was followed by an EOI for flexibility services, targeting a range of MW requirements across 10 substation locations (see Figure 16) in UKPN's Southern and Eastern licence areas.
As a result of the EOI and subsequent tender, UKPN has this year agreed bi-directional contracts with a small number of flexibility providers. One of these parties is domestic battery company Powervault, who will be providing flexibility services to UKPN, through a portfolio of 40 x 8kWh batteries across the London Borough of Barnet[25]."

So this shows that the domestic potential of flexibility services is realistic and happening now, reducing consumer costs and making the distribution network more flexible and secure, without huge power stations blighting the countryside.

1 H Vehicle to grid, V2G, use of Electric vehicles
The report on the examination of the benefits or otherwise of Vehicle to Grid (V2G) operation of electric vehicles (attached) concludes:
"Whole System value and decarbonisation potential of V2G
There will be an enduring value from variable/smart charging and V2G to the electricity supply chain, both in terms of local flexibility to the distribution grid and increasingly in energy arbitrage as price spreads and volatility increase with RES deployment.

By reducing the peak demand on the distribution grid, deployment of V2G could help save £200m of cumulative distribution network investment from 2020-2030 compared to unmanaged charging.

Relative to unmanaged charging, Smart Charging could generate GB whole energy system net savings of £180m annually (in 2030), with benefits throughout the GB power system. Additionally, V2G operation could generate a net saving of between £40M-90M/annum, depending on limits to V2G energy throughput.

V2G will compete with a range of technologies to provide flexibility to the system, in particular with stationary battery storage, 2nd life batteries, flexible gas plants, and Smart Charging.

Competition between flexibility sources means that the marginal value of flexibility reduces as its deployment increases. However there is a positive synergy when increasing both flexibility asset and VRES deployment; VRES induced variability provides the conditions to sustain cycling and revenues from flexibility assets, which in turn can reduce curtailment of renewable energy. "

Importantly for local consumers, the report concludes that a standard 7 kW EV charger could provide revenues of £436 a year, thus helping to reduce electricity costs which have continued to rise.
This is in contrast to the Applicant's proposals which will provide no direct benefits to consumers.

This confirms the European research which found that V2G services could save billions in grid reinforcement costs, and that this would be particularly significant in countries with large wind power resources, such as the UK. See attached (**1 H Vehicle to grid, V2G, use of Electric vehicles, EVs could save billions in grid**

costs Electrical evidence August.rtf).

Electric vehicle chargers are already being installed from several providers which have Dynamic load balancing which is used to avoid overloading the grid and also to ensure the most efficient use of power capacity.
They can also allow EV drivers to balance the energy usage of the charging station with other appliances in their home or building and also integrate with on site power sources such as solar PV. See attached (**1HG Vehicle to grid, V2G, use of Electric vehicles,** Smart charging solutions Electrical evidence August.rtf).

Conclusion: All the above involve existing equipment being used more effectively, thus providing lower costs to them and other consumers, while improving the resilience of the whole system, with much lower costs than the Applicant's proposals.

2 Identifying what is on the grid and local distribution network.
Clearly the system operators have a difficult job, and at the moment there is not a UK wide system of identifying what is connected.
However Western Power Distribution (WPD) and others have worked together to identify resources, and for WPD this showed previously unknown 15,000 EVs and PV systems were connected to their system, see attached (**2 Identifying what is on the grid and local distribution network** Electrical evidence August.rtf) .
Clearly this provides a significant stem in managing the distribution system, which can also be communicated to other players, such as the Grid.

3 Community Energy

A significant criticism of the Applicant's proposal is that it does not directly benefit local people, indeed disadvantages many of them, and the main financial benefit, if any, goes to the Applicant's company and its investors or partners elsewhere.

In contrast Community Energy schemes depend on community support and involvement and directly benefit local people in many ways, including direct payments, energy saving advice, environmental and other education, social and practical activities and improved social cohesion, a very important aspect in these troubled times.

There are many successful examples, such as Bay Wind Coop, one of the earliest, which has paid out around 7% every year as well as many local activities, this segued into Energy4All which generated and embraced many other coops, including the Westmill wind and solar farms.

For more information about community energy, see https://hub.communityenergyengland.org/, managed by Community Energy England, which also mentions the objective of "taking control of energy in their local area" - something that is clearly lacking in the Applicant's proposals as the local community has no control over the proposal and indeed has had to invest a huge amount of resources, with no recompense, to try and change it.

2 A Riding Sunbeams
A major new development has been the joint work of several community energy groups to create a project across the south east to power the electric railways.

The attached is their latest report which preceded the connection of the first solar system to the railway at Aldershot.
The project involves small groups of solar panels which are obviously easier to fit into suitable areas with far less disruption than the huge power station proposed for Graveney Marshes, and the energy is used locally, minimising distribution losses and the financial benefits are shared locally.

3 Wind alternatives
In Part 1, Location, of my Written Representation, I referred to the potential of the Cleve Hill Grid Connection being needed for expanding or upgrading the existing wind farm which is connected at this point.
A recent report shown in attached (**3 An increased rollout of onshore wind turbines across Europe could technically provide the continent with more than 10 times its existing electricity needs,** Electrical evidence August.rtf) shows that if the wind turbines were to be replaced with new turbines which are available now, the total power generated would increase dramatically because the new turbines can operate at both lower and higher wind speeds and therefore provide much greater Full Load Hours, hence far more MWh per annum..
However allowing the solar power station to connect here would prevent that efficiency improvement being

achieved, thus preventing the much lower cost wind power being provided.
Hence this grid connection capacity must be retained to enable this, especially as turbine costs are coming down and re-powering existing turbines is much cheaper than building a whole new system.

4 Local smart energy systems key to net zero, says ADE

The Association for Decentralised Energy (ADE) predicts that the traditional centralised approach will be replaced by a smart, user-led system, with local energy and consumers at the heart See attached (4 **Local smart energy systems key to net zero, says ADE, ,** Electrical evidence August.rtf).

It argues that the way to achieve this future energy system is through on-site flexibility and energy storage, energy efficiency, implementation of heat networks and on-site combined heat and power systems.

The ADE points to estimates made by the National Infrastructure Commission that reducing peak demand through energy management by 5% would reduce power system costs by £200 million each year and give consumers £790 million a year in added benefits.

And that peak power demand could be reduced by up to 15% if the UK achieves comparable levels of flexibility to other markets such as Australia and the US.

This means that the Applicant's proposal is not needed because it would not achieve the same benefits as local smart energy systems, and would cost more for consumers.

CLEVE HILL SOLAR POWER STATION
CHRIS LOWE Interested Party, reference: 20022096

Evidence Sources for Email 30/08/2019

1 DEMAND SIDE RESPONSE

1 A Demand Side Response (DSR): Uninterruptible Power Supplies as a Reserve

Eaton reports pilot success for UPS-as-a-reserve January 29, 2019 By Louise Frampton
missioncriticalpower.uk/eaton-reports-pilot-success-ups-reserve/

Two years ago, Eaton announced its move into developing technology that would enable participation in demand-side response (DSR) and set its sights on engaging data centres with the concept of UPS-as-a-reserve' (UPSaaR). The aim was to enable data centres to contribute to renewable energy, by helping to stabilise the grid, while earning revenue from their power assets.

The sector, historically, has been reticent about DSR, however, and many data centre providers have expressed concerns over the perceived 'risk'. With few publicised cases to allay their fears, the sector has been slow to come on board, but attitudes are now starting to thaw. Eaton's Mike Byrnes says that UPSaaR is showing increasing promise and a pilot project in Norway has proven that the concept can be rolled out to data centres without impacting resilience.

Byrnes revealed that Basefarm, a Norwegian data centre company, has trialled the service as part of a project led by Statnett, a Norwegian transmission system operator, and Fortum, a leading energy provider in the Nordic and Baltic countries.

As part of the project, Eaton 93PM and Power Xpert 9395P UPSs were upgraded with UPSaaR functionality. This capability enables data centre operators to work with energy providers to momentarily reduce the power demands of the data centre and even return power to the grid.

During the pilot, the UPSs were tested during a power plant failure that caused instability in the grid. The data centre reserves were the quickest to activate, providing the desired power impact in far less than the required two seconds, and faster than other reserves connected to the grid, such as pumps, industrial consumption and electric vehicles.

The pilot has proved that energy storage in data centres is a viable and fast-acting means of reserve to balance power grids and does not impact the UPS's primary function of securing data centre loads.

"Grids have stability issues for frequency, due to the increasing use of renewables, and the UPS is like the first responder – the 'paramedic'; it is the digital interface. The testing we have undertaken is going extremely well. Any fears over risk, expressed by customers, have been allayed from an engineering perspective, but also in terms of having a secure software connection back to the aggregator," commented Byrnes.

Having completed successful pilot projects in the UK and Scandinavia, the UPSaaR concept is now ready to be offered to DSR markets as a retrofit solution or as inbuilt functionality in new data centres. According to Eaton's estimates, a data centre could potentially earn ¤50,000 per MW of power allocated to grid support per year, depending on the local market. However, revenue streams do not appear to be the motivating factor, according to Byrnes.

"We pitched this concept two years ago as offering 'easy revenue', but what we have discovered is that the main driver is not around revenue but sustainability. A CTO from a very large facility commented that the greatest risk to the business is the fact that the data centre is a burden on the grid by virtue of its presence, size and capacity. As this contributes to the risks of grid frequency, helping to stabilise the grid through UPSaaR helps to mitigate risk…Eaton has also partnered Microsoft on the development of dual purpose UPS, in the US, and it is all about sustainability," commented Byrnes.

He highlighted further emerging trends in the data centre sector including growing interest in replacing diesel generators with batteries, as well as increasing demand for microgrids. A growing number of number of data centres are seeking independence from the grid, particularly in countries that have been hit by extreme weather events in recent years. Modular solutions are also gaining traction, according to Byrnes, and this is being driven by the rapid growth of the colocation market.

"It is a great time to be in the data centre market. Not only has there has been growth in the hyperscale space, but the hyperscalers have also had an impact on the colocation sector.

"This has led to a number of things: there is a need to move fast as there is a lot of competition in the market; and there is a need for infrastructure that is right-sized and delivered on time. This is driving the pace of innovation – not just in terms of what we do, ie the technology, but also in terms of how we do it. This is driving increasing interest in modular designs," he concluded.

1 B Demand Side Response: Incentivising Domestic Demand Response

29 Jul / 2019 Alice Grundy, Current±
www.current-news.co.uk/blogs/current-disruptors-gengames-stephane-lee-favier-on-how-to-incentivise-domestic-demand-response

Fresh off the back of a trial with Northern Powergrid, gamification firm GenGame is ramping up what its consumer-facing demand side response app has to offer. The app incentivises domestic demand side response through opportunities to win prizes, a points system and mini-games.

It brings together EVs, solar PV and battery storage, providing information such as personalised solar forecasts and charging insights, helping consumers to shift their energy consumption.

The firm is also trialling vehicle-to-grid with Ecotricity consumers, adding to its current EV offerings.

Stephane Lee-Favier, GenGame CEO, spoke to *Current±* about the evolution of GenGame since the Northern Powegrid project, working with suppliers and the best way to incentivise domestic demand response.

How does the GenGame app work?

What we're trying to do is build a mobile app platform that we then sell to the supplier.

The two key things about it are that it's designed for an everyday user over someone who is knowledgeable about energy. The logic is that a lot of low carbon tech is becoming mainstream. Smart meters are being rolled out, lots of people have solar and there's interest in electric vehicles and domestic storage. Over the next few years these will continue growing into homes of people who are not your typical tech or energy expert. If you look at a lot of the consumer interfaces for those technologies, they often look like mini control rooms. Our focus is very much on making it engaging, making it consumer focused, making it simple and making it fun.

Then the second thing is bringing all these technologies into one place. Consumers don't want multiple energy apps to manage their battery, their EV charging and their solar. There's value in bringing those into one place. Things like demand flexibility mean you want to look at controlling a lot of these devices in one place in a coordinated fashion.

If you're thinking about something that relates to energy, the more useful stuff you can put in there, the more likely a consumer is to keep it on their phone. If you're doing something with behaviour change, you need a space in their life and the way to do that is to be useful.

The route to market is through the supplier as they're the companies consumers are most likely to expect to receive these services from. They can monetise demand flexibility and they're also extremely keen to acquire and retain customers so there's a business case for providing something that engages their customers and makes them less likely to switch.

We're building the app and then selling it as a white-labelled product which we add their branding to. They then roll it out to their customer base.

What were some of those learnings from the trial with Northern Powergrid that you've applied to the app?

It was a three-year project and when I look at what we had when we started and where we ended, it was a huge evolution.

We learned a lot about how you develop digital products. It's a very iterative process. The DNOs are used to big infrastructure projects where you do a lot of planning and modelling and you execute it, you build it, and you know it's going to work. With things like consumer engagement apps- you can't model humans. The most effective way to do it is to test it.

In terms of gamification, we learned that it works. The cost of the incentives we were offering consumers to shift their energy consumption was 20 times lower than similar projects that didn't have gamification. We were offering around 40p, and for that 40p consumers were reducing around 10-12% peak time consumption. The main difference in the approach is how you're framing it. Offering a chance to win £100 instead of offering 10p for turning a washing machine off is a much more engaging way of framing that same incentive.

We also learned about automation. One part of the trial was behavioural and another was leveraging automation. You need engagement with both because even if there's automation there, you need a reason for the customer to want to give you control of that and set it up in the first place.

What automation does do is it improves the longevity of the DSR. For a lot of consumers, eventually that enthusiasm wears off. Once the automation is set up and you're given control, you don't need that consistent engagement you'd need with a behavioural change.

What sorts of consumers engaged most with DSR?

In general terms, we were getting roughly around 80% of the reductions from 20% of the homes. When you start digging into those households, it tended to be households that had a lot of low carbon tech, for example EVs or heat pumps. In terms of a marketing cost of recruiting someone for a DSR programme, it costs the same to recruit someone who has a heat pump as someone who doesn't.

So if you're trying to do this cost effectively, you want to focus on those people that have low carbon technologies and that's where we've ended up. If we build useful features into our product for those households, we're more likely to be able to target them.

Why have you made the switch from working with a DNO like Northern Powergrid to partnering with suppliers?

With a DNO, they don't usually have a relationship with their customers. Most people don't know who their DNO is but do know who their supplier is.

The suppliers already have relationships with consumers around energy so in terms of having the biggest impact, the suppliers are the best way to do it. They're also the ones who can potentially extract the most value from it.

What makes your app different to other demand response projects?

There are a lot of projects looking at demand side response; we're not the only ones. But there's a lot of focus on the technology as the enabler, for instance in peer-to-peer (P2P) trading and smart metering.

All these ideas are great and key to households benefitting from flexibility but you have to frame it in a way that's engaging to consumers. That's something I feel is often overlooked. The technology is one part of the puzzle. Bringing consumers along in a way that makes it interesting and understandable is the other.

1 C Demand Side Response: Incentivising Commercial Demand Response

Current± Disruptors: Grid Edge's Jim Scott on how data is enabling commercial demand response

15 Aug / 2019 Alice Grundy Current±

Grid Edge – an energy tech start-up span out of Aston University – is aiming to bridge the gap between the energy industry and its consumers.

Focused on enabling commercial energy users to participate in demand response and manage their energy consumption, Grid Edge uses machine learning and data to enable flexibility services from commercial energy users.

Jim Scott, co-founder and chief product officer at Grid Edge, spoke with *Current±* about how to allow commercial energy users to provide flexibility services, the need for collaboration between commercial buildings and DNOs and the different terminology surrounding AI and data.

Why is it important to facilitate demand response from commercial energy users?
It's our view that the fundamental issue is that the grid support required for technology like EVs or heat pumps has always been done on the grid side's terms; it's never really been done on a customer's terms.
All of our customers have really ambitious carbon targets and have their neck on the line about it... And I think their view is that they're being let down a little bit by the industry.
There's been very little active communication between consumers and their supply side partners and those relationships have been built around procurement and billing. I do think both DNOs and suppliers have been trying to change this recently as suppliers look more towards service focused offerings and DNOs are trying to become more consumer centric.
What we're doing at Grid Edge is building the tools to help building operators engage with the future energy system. We think that system will be dominated not by how many kWh you use or generate but by when you consume or generate. We want our customers to be ready to proactively address that opportunity.

What can the DNOs and suppliers do to help support this form of flexibility?
We would like to see a much more collaborative approach from the networks. We think that active network management is well within the capabilities of most commercial energy users but we don't see those schemes coming to market properly before the next price review at the least. It's a shame as the current practice seems to be a less efficient deployment of the money coming into the DNOs.
In terms of suppliers, I would like to see them really start to push the boundaries of what their customers can engage with around flexibility services. We see some of our upstream partners starting to do just that at the moment with some really innovative tariff products being developed. But there seems to be a lack of confidence when it comes to integrating those offers into the core business sales process. We think the consumers are ready to engage on this topic if it can just be packaged in the right way.

How much can commercial energy users contribute to alleviating grid constraints?
I think the answer to constraints should be a blend of technologies. I can see a case for supply side storage in certain conditions but I think the lowest cost flexibility options will always be on the demand side if the incentives and business models can be aligned correctly. We think it's more of a continuum between high-availability, high-cost supply side storage and lower-availability, lower-cost demand side dynamic storage and demand side management.
On the other side of things, all of our customers want to put in new electrical capacity and some of them are talking about doubling or tripling their load in three years due to changing out gas boilers, installations of EV charging kit or building expansions.
Capacity constraints are definitely on the mind of those customers who are thinking longer term about large electrification projects and they've learned to open a dialogue with the DNOs about large projects early in development. We don't see many sites where the customer is being offered any lower cost alternative to upgrade, however, and we expect to see more of our customers being offered active network management style connection agreements in the near future.
What we're trying to do is give the customer the power to have that conversation on their terms instead of having to be told by the DNO what the deal is. At the moment, the terms are all written out as what suits the grid and the customer has to jump. The result of that is that you'll probably end up with lots of batteries and diesel generators and you won't use the inherent flexibility we already have.

Grid Edge's website uses the term AI but you've said you prefer the term data science. Why the difference?
When we talk to investors, we often use the phrase AI when the reality is we, like most analytics companies, use a wide range of methods and algorithms to solve the problem at hand. We tend to say AI as I don't think the investor community is necessarily quite ready to know the difference between a statistical method and an analytical method.
I do think it's just about finding the right fit and it's pretty clear when it comes to talking about the technology that some investors do really get it and can have quite a detailed conversation and understand the nuance, whilst for others it's maybe a bit of a trend.
I'd like to think as these technologies become more common place the terminology will move away from the broad catch-all lexicon and back to descriptions of what type of methods and technologies are at work.

1 D Reducing energy costs or increasing earnings for local generators.

Peer-to-peer energy trading could trigger earnings boon for Distributed Energy Resources (DER), study finds
www.current-news.co.uk/news/p2p-cost-efficiency-findings-could-accelerate-domestic-renewables-adoption-says-lo3
21 Aug / 2019 Alice Grundy
Peer-to-peer trading could enable those with distributed energy resources (DERs) to earn up to 37% more for their electricity, according to LO3 Energy.
The energy tech firm conducted a 12-month local energy marketplace (LEM) trial in Australia looking at the associated network and market charges of P2P, which it said is one of P2P's main challenges.
Three scenarios were modelled - one scenario where neither buyers or sellers paid network charges, one where the costs were split between the two and one where all costs were charged to the consumer.
The modelling was conducted alongside Siemens, Sustainable Australia Fund, CommPower Industrial, Simply Energy and Dairy Australia.

It found that trading local energy within a community incurs fewer losses and is more cost efficient than transmitting power over long distances.
When the consumer paid the costs – a scenario LO3 said is most consistent with existing markets and regulation – they could potentially save 6-12% by buying locally. And those selling the electricity generated from DERs could make 18-37% more than they currently do.
The findings could increase the adoption of DERs in much the same way that the economics of DERs themselves have accelerated demand from consumers, LO3 said.
LO3's blockchain-powered energy trading platform was used in the trial, with the 100 participants paying a small fee to access the platform it intends to launch commercially later this year.
The firm is involved in 10 trials worldwide, including Centrica's Cornwall LEM trial. However, in the UK P2P trading can only go ahead as part of Ofgem's regulatory sandbox due to regulation restricting consumers to one electricity supplier. This creates barriers for P2P, where a consumer could be buying electricity from any number of neighbours.
Belinda Kinkead, director of LO3 Australia, said: "The study showed the community wanted to embrace new technologies, wanted to keep energy spend in the community and wanted to buy their energy more cheaply.
"The test results demonstrated that even under existing restrictions a local energy market delivers that. The next step is to get these markets set up and then explore regulation changes to provide even bigger benefits."

1 E New partnership for flexibility
Flextricity
Flexitricity bids to 'revolutionise' DSR industry with BEIS-backed pilot 02/**Jul / 2019**
www.current-news.co.uk/news/flexitricity-bids-to-revolutionise-dsr-industry-with-beis-backed-pilot
Flexitricity has partnered with eight organisations on a new trial which it says holds the potential to "revolutionise the demand side response industry".
The flexibility provider is participating in the government-funded Quickturn project, which aims to provide realistic opportunities for smaller commercial energy users to benefit from demand side response (DSR).
Flexitricity, which has around 500MW of flexible assets under management, is partnering with a host of SMEs and public bodies, helping some of their locations reduce energy costs while providing vital balancing services to National Grid.
The pilot is looking to tackle one of the DSR industry's key hurdles in that smaller sites have effectively been ruled out of participating in the market, rendered uneconomical by the high entry costs associated with hardware, communications and implementation.
Flexitricity will look to dispatch flexible energy consuming assets including cold storage, air conditioning units and heat pumps, aided by the University of Edinburgh's Institute for Digital Communications which will contribute its expertise in emerging communications technology.
The pilot is set to get underway, and findings are to be shared next year.
Dr Alastair Martin, founder and CSO at Flexitricity, said that small businesses will have an important role to play in helping National Grid meet the country's energy demands as the low carbon transition continues.
"Flexible energy use is a vital part of a greener energy system, balancing variable renewable generation and growing demand as heat and transport are electrified. Flexitricity's mission is to make this feasible and economically attractive for all types of energy user.
"From this perspective we are now looking forward to embarking on the trials and proving a cost and time effective solution that fits the requirements of National Grid and helps smaller commercial energy users take advantage of the UK's need for flexible power."

Kaluza Sonnen partnership
www.current-news.co.uk/news/kaluza-and-sonnen-pen-platform-partnership-to-ramp-up-grid-flexibility
Energy tech firm Kaluza and battery storage manufacturer sonnen have penned a new partnership to introduce new flexibility onto the UK's grid.
Kaluza, the tech division of energy group OVO, will integrate its smart energy platform with sonnen's own virtual power plant technology, enabling the latter to import and export energy when required for grid flexibility purposes.
Sonnen's VPP platform has already seen success in the UK and is currently playing a pivotal role in Centrica's Local Energy Market project in Cornwall. A total of 100 sonnenBatterie systems have been installed in homes and businesses, systems which are digitally linked.
Kaluza's own technology has also been in development for some time. In February 2017 OVO made its maiden acquisition in purchasing smart grid technology developer VCharge, whose platform OVO has continued to develop.
At the time, the company said the deal underlined its intent to develop solutions which could "harness the disruptive power of technology" to solve problems facing the sector, before unveiling an entire suite of energy technology products in April the following year.
Kaluza said the partnership with sonnen is the first in a series of upcoming collaborations with leading hardware manufacturers and service providers, something which it added signalled a "significant step forward for the energy industry".
Stephen Fitzpatrick, CEO and founder at OVO Group, said: "We will only achieve the shift to electricity through collaboration. The aim is to give customers the greatest possible choice, and the control to adopt an electric system.
"Batteries such as sonnen's are critical to our energy security as they support a resilient, independent energy system as well as providing back up supply. Sonnen has created a world-class energy storage technology and we look forward to working together to

deliver an intelligent, zero carbon grid."

Sonnen has also been busy, and in January became the latest energy company to be snapped up by Shell New Energies as part of its bid to seize the lead in emerging technologies and business models.

Sonnen batteries will be offered to Shell's one million energy supply customers in the UK, Shell Energy CEO Colin Crooks confirmed in March, and sonnen is also playing a role in battery storage developer Anesco's launch of a residential storage offering for the UK market.

Commenting on today's news, sonnen chief Christoph Ostermann said the integration with Kaluza's platform would provide a large volume of flexibility to its customers and the grid, and "automatically reduces energy costs and carbon emissions" in a "win-win situation for everybody".

1 F Improving the Networks for flexibility

The network companies who are members of the Energy Networks Association are pushing ahead with flexibility, as part of its Open Networks Project, with new proposals within a consultation on application interactivity and connection queue management which outlines plans to make it easier for more flexible energy projects to connect to the grid.

The ENA say: "The Open Networks Project is leading the way on our much needed transition to the smart grid, looking at ways we can speed up connections, encourage new flexible energy markets and deliver Net Zero."

See: www.current-news.co.uk/news/flexible-energy-projects-could-jump-connection-queues-under-network-modernisation-plans

1 H Vehicle to grid, V2G, use of Electric vehicles

EVs could save billions in grid costs

Smart charging and vehicle-to-grid (V2G) technologies could reduce grid costs as deployment of EVs increases, according to a new Element Energy report.

The report, which was commissioned by The European Federation for Transport and Environment (T&E), Enel, Iberdola and Renault-Nissan, found that by 2040 smart charging could save between €0.5 and €1.3 billion of prospective grid upgrades per year, depending on the country, even after incorporating the costs associated with additional smart charging infrastructure.

It found the biggest impact would be in countries with high levels of wind, and with countries sporting large amounts of PV in need of flexibility from assets such as utility-scale battery storage.

The study, which looked at different future scenarios, analysed the costs and benefits in the UK, France, Italy and Spain. In its most conservative scenario, it predicted that the total number of EVs in Europe in 2040 will be 94 million, adding up to a total of 3,955GWh of storage capacity.

It found that collectively, EVs could form a 'giant battery on wheels' that would reduce curtailment rates and provide electricity back to the grid, lessening the need of peak plants on a daily basis.

See: www.current-news.co.uk/news/evs-could-slash-grid-costs-but-must-be-supported-by-eu-policy

Smart charging solutions

www.current-news.co.uk/news/evbox-partners-smappee-launches-new-smart-charging-solution

EVBox has entered into a multi-year agreement with energy management company Smappee for the launch of a new smart EV charging solution.

The two companies are to work together on the global rollout of smart charging and are launching EVBox Smart Charging, a smart charging solution universally compatible with EVBox's chargers.

Dynamic load balancing is to play a key role in the solution, which is used to avoid overloading the grid and ensure the most efficient use of power capacity.

A module is added to the electric panel that allows EV drivers to balance the energy usage of the charging station with other appliances in their home or building.

EVBox's chargers can also be integrated with solar PV through EVBox Smart Charging+. The company is not alone in looking to integrate solar with EV charging, with Rolec EV launching a solar powered charger earlier this year, and myenergi's Zappi product also among the market leaders in this field

A mobile app provides real-time charging data, as well as data on solar production and electricity consumption.

This is the latest of EVBox's partnerships, having partnered with Mercedes-Benz and Engie for an EV 'one-stop-shop'. Engie, which acquired EVBox in 2017, has also been ramping up it's EV offering, acquiring ChargePoint Services last month.

Job Karstons from EVBox said the partnership opens up possibilities for EVBox and its customers.

"Smart Charging features are highly requested in the EV charging market right now, and thanks to us teaming up with Smappee we can now offer such features including dynamic load balancing and integration with solar panels."

2 Identifying what is on the grid and local distribution network.

15,000 previously unknown EVs and solar panels identified on WPD network Posted by Anna Carlini **on 29 March 2019 at 5:04 pm http://www.yougen.co.uk/blog-entry/3100/15'2C000+previously+unknown+EVs+and+solar+panels+identified+on+WPD+network/**

Results have been published from an innovative project revealing a large number of previously unknown low-carbon technologies in Wales, the South West and the Midlands. Western Power Distribution (WPD), the company responsible for electricity distribution in these regions, funded the project to improve visibility of low carbon technologies, hoping to forecast the location of electric vehicle, solar panel and heat pump 'hotspots'.

In November 2018 ElectraLink, Western Power Distribution (WPD) and computing giant IBM announced they would be collaborating on a project to identify the number of electric vehicles and other low carbon technologies on WPD's local energy distribution network. This project is known as the Low Carbon Technologies Detections project.

Innovative approaches have been applied throughout analysis, such as utilising AI to combine previously independent data, such as text and images, to improve the identification of low carbon technologies. It also drew on ElectricaLink's energy market database and IBM's Watson studio to produce insights in the demand for a variety low carbon technologies.

The changing future of energy distribution calls for a project of this kind. The way that energy is generated and distributed is changing rapidly. One of the main difficulties that distribution companies are coming up against is the traditional one-way flow of energy networks – existing networks are designed to distribute large amounts of electricity from a small number of power stations to a large number of buildings. Fundamentally, they are designed only to flow in *one* direction. However, our relationship with energy is changing as more, as onsite microgeneration is increasing and electricity is being fed into the grid from domestic dwellings.

https://www.electralink.co.uk/2018/11/low-carbon-technologies-lct-detection-project/For example, Ofgem states that around a quarter of electricity now comes from renewables. This means that the changing generation, distribution and use of energy are resulting in the need for an energy network which can flow in variety of directions, and ultimately respond with flexibility to our modern relationship with energy. It also means that smart charging and other smart technologies are going to play an increasing role in the management of energy distribution systems.

Therefore, it is of high importance for DNOs, the companies responsible for managing the networks that deliver electricity at a local level, to understand the current number and location of low carbon technologies. This knowledge can help paint a clear picture for energy management in the present and provide a basis to make predictions and prepare for the future. The Low Carbon Technology Detection project did exactly this.

On the 21 March the dynamic results of the project were released, showing that a previously unknown 15,000 electric vehicles and solar panels have been identified on WPD's network. This very significant figure equates to 13% more households with EVs or solar panels on WPD's network than had been previously thought. The project also demonstrated the impact of LCT on households' electricity usage: showing that households with solar panels installed used 25% less electricity than those without.

The project is being held up as a demonstration of the impact of technological advances in energy analysis. ElectraLink deemed the project 'unprecedented' and a pioneer project which can 'pave the way' for new concept models to be explored.

WPD's DSO systems and project manager Roger Hey said the project was an example of how data and other intelligence is being used to drive innovation.

3 An increased rollout of onshore wind turbines across Europe could technically provide the continent with more than 10 times its existing electricity needs

Various studies have attempted to estimate the wind capacity of the entire continent, adding to the body of evidence concerning the technology's feasibility. These studies take into account factors such as weather patterns and hypothetical locations for windfarms to gauge the maximum potential wind power has across the region.

These studies have tended to estimate a total European capacity of between around 8 and 12 terawatts (TW), which would result in a total annual generation of between 16 and 21 petawatt hours (PWh). Given the annual electricity generation for Europe – according to BP's Statistical Review of World Energy – is just 3.6PWh, this already vastly exceeds the amount required on the continent.

However, in their new paper the authors explain that they think this is an underestimate when considering future wind generation potential in Europe.

Futuristic designs
The figure the researchers arrive at is 13.4TW of installable wind capacity across Europe, only marginally higher than previous estimates.
However, the big step up comes from their estimate of average annual generation potential, which is 34.3PWh. This is 13PWh higher than the nearest estimate made by other scientists and 10 times more power than the BP data suggests Europe uses today.
In their paper, the authors attribute this discrepancy partly to their methods of identifying eligible land for windfarm construction and estimating weather. Crucially, they also emphasise their focus on futuristic turbine designs of the type that are expected to become standard in the coming years.

Source	Eligible land [10^{6} km^{2}]	Capacity [TW]	Generation [PWh]	Average FLH [kWh kW^{1}]
This Study	1.35	13.4	34.3	2560
Error! Hyperlink reference not valid. Bosch et al.				

Carbon Co-op

regen transforming energy

Energy Community Aggregator Services (ECAS)

A feasibility study analysing community-based aggregation of domestic and small organisation consumers using the UK smart metering system, commodity hardware, common open standards and open source software.

Part of the BEIS Flexibility Markets Feasibility Study Competition

August 2018

1 Executive Summary

1.1 Energy Community Aggregator Services

The Energy Community Aggregator Service (ECAS) is envisioned as an energy system intermediary that will play the role of an Aggregator, enabling multiple householders to take advantage of emerging local flexibility markets. The route to market for ECAS is as a federated body or social franchise, which enables small, not-for-profit and sometimes voluntary Community Energy groups to take advantage of local flexibility services via ECAS' pooled technical services, capacity and workforce. The nature of local flexibility markets suggests the creation of a federated energy system Aggregator intermediary which achieves both scale and a locally specific focus, has a great deal of potential. The Community Energy sector has a number of recognised strengths and opportunities including high levels of trust, a local focus and access to 'early adopter' householders that could be taken advantage of by such a model.

1.2 The role of demand side measures

Demand side measures are increasingly seen as crucial to meeting the UK's ambitious climate change targets as well as offering the potential for reduction in costs and improvements in grid reliability for UK consumers. Demand Side Response (DSR) has long been used as a resource by the system operator to support grid operations. However, there is also a 'long tail' of smaller appliances and a growing 'fat middle' of newer low carbon technologies embedded in distribution networks which to date has not been exploited for demand side response. The falling cost of control and communication systems delivered by the Internet of Things and Cloud Computing as well as the potential for new revenue streams from energy system actors willing to purchase this flexibility is moving aggregation of small amounts of flexibility towards commercial viability.

1.3 DNO flexibility procurement

Our analysis of DNO local flexibility efforts has highlighted that they are at different stages in exploring the potential of local flexibility. A range of approaches to this are currently being explored although they are generally characterised by longer term procurement of services under bilateral contracts rather than a more market-based approach as we have proposed in ECAS. New operational and business functions and approaches will need to be developed by DNOs to publicise and operate flexibility in either case.

1.4 DSR market is small.. for now

In this project, we have concluded that the current market for domestic DSR is immature and small. Recent announcements of local flexibility schemes by UK DNOs have improved the viability of potential schemes (although currently very geographically restricted). Reforms will be needed to existing ancillary services, capacity market and balancing mechanism to support the inclusion of aggregated domestic loads. These reforms centre on allowing aggregated portfolios (already possible in some markets) and changes to metering and assurance requirements, although others are likely to be required. Using the new local flexibility schemes, which typically have lower requirements, may be a route to market for new offerings, although partnerships with DNOs maybe required to support this activity initially.

Due to the highly geographical nature of this activity, community orientated schemes may have some advantages over larger top down solutions. There are also a range of consumer issues associated with domestic demand side response which will need to be addressed including data privacy and security and remote control of assets. These are partly issues of trust and confidence and a community orientated Aggregator may benefit from higher levels of trust from consumers (or member/stakeholders).

1.5 Achieving viability

Extrapolating from publicly available data, in particular the indicative revenues published in WPD's Flexible Power service, we have concluded that local flexibility schemes are only likely to provide value to those homes offering large automated loads (such as electric heating, batteries, and electric vehicles) for control. However, even then the activity is likely to be low margin and revenue stacking with income from other flexibility markets (and potentially other business activities such as ESCo) will be important for commercial viability. Similarly, manual DSR is unlikely to ever attract any income or be of value to other actors and should not be pursued in future schemes. In conclusion, viability is likely to be achieved by scale and when local, regional, and national markets for flexibility become more mature.

1.6 Developing technical systems

ECAS has a range of options for procuring and operating its system with our preference for open source systems based on common open standards. Due to the low margin nature of the activity a higher number of intermediaries will mean lower profit share which may undermine the business case. We therefore believe ECAS will find most success acting directly as an independent Aggregator rather than contracting out these functions to others. This however presents challenges in developing systems, which will require substantial investment. Existing Aggregators, large technology companies (Google/Amazon), Suppliers, manufacturers of systems, and 'platform' start-ups already have made these investments and it maybe that technology partnerships with these would be the best way to take ECAS forward. On the other hand, this is a new and fast developing market and there maybe future opportunities for an independent Aggregator to develop its own better technology.

1.7 Technical Project Recommendations

A technical feasibility assessment of the ECAS local flexibility concept has shown that some barriers remain to implementation. We have used these barriers as the basis for several recommendations to BEIS and the wider sector:

- **Consumer Access Devices (CADs)** will be an essential component in the provision of near real-time demand data from UK smart meters but their use cases are not explicit in SMETS or other parts of the SEC and up-to-date guidance around their widespread and systematic use is yet to be issued.

- There is currently **no user role for Aggregators** in the smart metering system DCC and they currently would have to apply and participate under the 'Other' user role. It may make sense to analyse the Aggregator use case in relation to the DCC and define a new user role and set of functions in DUIS etc. This will also help in monitoring how Aggregators are using smart metering data.

- A key missing component in the establishment of local flexibility markets is information about the **operational status** of distribution networks and how this will be created/provided/guaranteed. USEF describes a 'Common Reference Operator' role and we believe there is a compelling case for the establishment of something like this in the UK market to act as a clearing house for information where access to it may otherwise be monopolised and controlled by the DSO to the detriment of other actors.

- Our review of the ADE **Code of Conduct for Aggregators** has found that it is currently lacking in several areas which will become more important when working with large numbers of domestic consumers; it currently does not recommend the implementation of any standards for information management (e.g. IASME); there is no recommendation around live monitoring which will be important for preventing attacks in progress; there is no requirement to notify government or regulatory agencies in the event of an attack (e.g. National Cyber Security Centre).

1.8 Policy environment

We have identified some key policy initiatives which support ECAS, such as the Smart Systems and Flexibility Plan and Faraday Challenge (and recent announcements on electric vehicles). The main policy risks stem from the delays in the smart meter rollout. ECAS relies more on the functionality of smart meters rather than the level of penetration. So provided the key functionality relating to the DCC and CADs is implemented and any consumer who wants a smart meter can continue receive one, these risks will be mitigated. Local flexibility schemes also need a clear route to market and scale and we have highlighted some concerns around the regulatory sandbox approach which in some cases may be preventing this.

Our analysis of the regulatory environment has highlighted some areas for clarification and development around the role of independent Aggregators. There has been some activity in this area recently with Ofgem publishing a letter outlining their views as well as proposed code changes (P344/P354).

We believe a whole-system approach is required so that independent Aggregators can access markets on an equal basis to other parties but also take responsibility for the imbalance caused by their activity. There could be different solutions to this. Establishing independent balance responsibility parties (BRPs) in the UK with equal primary access to wholesale and balancing markets (as is found now in some EU countries) would potentially simplify these arrangements and lower the barriers to accessing these markets. This could be achieved by extending proposals found in P354 or otherwise. Aggregators can then appoint or become BRPs as a one-stop-shop for accessing wholesale and balancing markets. The alternative would be to add parties in an ad hoc fashion to existing markets which will multiply the costs involved and undermine the complex value proposition of flexibility services.

1.9 Next steps

Local flexibility markets are at a crucial stage of development and the partnership's view is that a demonstrator project (funded by BEIS and/or other stakeholders) aligned with strong engagement from one or more DNO has the potential to generate significant real-world data to inform ongoing policy, technical and business model development and crucially consumer engagement.

Alongside any demonstrator, the partnership will contribute the findings of this report to the ENA Open Networks Future Worlds consultation, ECAS has many similarities to the 'fifth world' described there and so we hope will be a useful contribution to the discussion, in addition to other smart system consultations and calls for evidence.

Alongside this project, under the BEIS Domestic DSR programme, Carbon Co-op, Regen and other partners have begun development of a domestic demand side response system based on OpenADR and the UK smart metering system which could in future be used to test a USEF-style local flexibility scheme in the UK. The aim of this is to develop a proof of concept to demonstrate the efficacy of open standards in demand side response and flexibility.

About the project
Authored between May and September 2018, by a partnership of Carbon Co-op, Regen and Community Energy Scotland, this feasibility study assesses the potential for local flexibility markets to be made accessible to domestic and small community organisations, through the development of a community energy-based aggregation model.

About the report
Work Package 2 describes and assesses the **business opportunity** for a community-based Aggregator flexibility provider, ECAS, in terms of current and emerging DNO income streams and provision of services to domestic and non-domestic end users.

Work Package 3 assesses the current and emerging **DSO market** potential interviewing DNO representatives as well as Aggregators to better understand market dynamics, trends and opportunities.

Work Package 4 is a **technical analysis** of the standards, tools and components necessary for a fully integrated local flexibility market system and assesses the development, operational and other costs for this system to function for a range of potential flexibility assets.

Work Package 5 places this project in a policy context, examining the relevant legal and regulatory factors that must be taken in to account.

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2 ECAS Business Planning

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2.1 Introduction

The Energy Community Aggregator Service (ECAS) is envisioned as an energy system intermediary that will play the role of an Aggregator, enabling multiple householders to take advantage of emerging local flexibility markets. The route to market for ECAS is as a federated body or social franchise, which enables small, not-for-profit and sometimes voluntary Community Energy groups to take advantage of local flexibility services via ECAS' pooled technical services, capacity and workforce.

In this section we outline the business and governance issues relating to ECAS as well as its potential market positioning and competitive advantages.

2.2 Community Energy

2.2.1 Definition

DECC's Community Energy Strategy 2014 defined Community Energy[1] as:
"...community projects or initiatives focused on the four strands of reducing energy use, managing energy better, generating energy or purchasing energy. This included communities of place and communities of interest. These projects or initiatives shared an emphasis on community ownership, leadership or control where the community benefits."

It estimated that up to 5,000 such groups existed in the UK at that time.

Community Energy groups can generally be typified as:

- Not for profit, with surplus re-invested back into communities
- Member owned and controlled.
- Motivated to take action on climate change and other environmental issues.
- Locally based.
- Volunteer run or featuring high levels of volunteering.

Most are involved in developing renewable energy generation but many are also involved in energy efficiency and smart energy applications with 17% of respondents to the Community Energy England State of the Sector Report 2018[2] involved in 'smart energy' activities and trials.

Community Energy groups often take advantage of the Community Shares[3] route to raising capital, a non-regulated investment methodology for registered societies in which equity shares are sold in the business whilst maintaining a one member, one vote governance model.

[1] Community Energy Strategy 2014 defined Community Energy, DECC, 2014
[2] State of the Sector Report 2018, Community Energy England (https://communityenergyengland.org/pages/state-of-the-sector-report-2018)
[3] Community Shares website (http://communityshares.org.uk)

The use of Feed in Tariffs and export tariffs led to a 'standard' Community Energy business model and a steady growth of groups, however, changes to incentives mean that organisations are seeking to diversify and looking for new opportunities.

2.2.2 Advantages of Community Energy

Community Energy groups generate a range of social and environmental benefits in their areas of operation.

Building stronger communities
Community energy activity can bring local people together to achieve something for their community, fostering common cause and empowering communities to take action on issues that matter to them

Developing new skills.
Members of the community can benefit from opportunities to learn new skills through involvement in community energy activity; some schemes have specifically engaged young people in work experience or energy and climate change education activities.

Financial benefits
Community energy presents opportunities to generate income for the community but also through local economic development by procuring from and developing local supply chains.

2.2.3 Key Strengths Weaknesses Opportunities and Threats

As noted, Community Energy groups are new to participating in smart systems and offering flexible services. Here we carry out a SWOT analysis analysing the sector's suitability to participate in local flexibility markets.

Strengths • Existing infrastructure ie organisational capacity, funds, expertise etc. • Trusted local profile with public and key stakeholders • A foothold in generation with the ambition to go further • Passionate, committed. • On the ground, local knowledge. • Can mobilise capital from Community Share issues relatively quickly.	Weaknesses • Relatively small sector in comparison to the energy sector as a whole. • Level of technical knowledge and expertise is generally low. • Ability to raise large amounts of capital quickly is limited. Governance structures often precludes venture capitalist investment. • Often limited to specific local areas.
Opportunities • A need to diversify and find new income streams. • Access to volunteers with skills and enthusiasm • Policy alignment with regards to Local Energy and Local Energy Communities.	Threats • Competition from private sector. • Regulatory requirements require large investment of staff and resources. • Inability to scale quickly.

• Members are often early adopters with smart tech eg EVs, PVs, heat pumps etc.	

Table 1. Strengths, Weaknesses, Opportunities, Threats analysis for Community Energy

2.3 ECAS in detail

In WP3, section 3.6, we assess the market for local flexibility and implications for the ECAS model. These are summarised here.

Finding	Implication for business model
DSO markets are at very early stages.	Viability of the model is some years away, model needs to remain flexible.
Amount of income on offer per kW/MW is likely to be modest.	Very large scale and value stacking via other income sources is required to ensure viability.
Income likely to vary significantly, largely according to location.	Ability to take advantage of locally specific conditions is required.
Systems for data collection, verification, and monitoring required.	Aggregator access to DCC and CADs is necessary.
Automated demand management required to meet baseline, entry and operational requirements of the DSO	Aggregator access to automated control systems is necessary.
Uptake of large flexible load technologies needed.	In early stages, there will be a premium for signing up householders with these technologies.

Table 2. DSO local flexibility market findings and implications for ECAS.

2.3.1 Role

The energy system role ECAS and the business model it adopts are informed by:

- The availability of value from DSO local flexibility markets (WP3).
- Technical constraints and opportunities (WP4).
- Current regulatory constraints and anticipated developments (WP5).

As identified in the SWOT analysis above, Community Energy groups benefit from a trusted, locally-focussed profile within the energy sector and as such seem well suited intermediaries to take advantage of local and temporally specific flexibility markets.

Conversely, very locally-focussed groups tend to lack the technical expertise, capacity and access to aggregation platforms necessary to take advantage of these markets. Furthermore, given that local constraints and conditions may change over time, should a local group develop a local flexibility business model in a specific locality, the income stream may reduce or dry up completely as energy system conditions change.

A solution to this tension is a hierarchically tiered approach. ECAS will be constituted to operate at a regional, national or even pan-European level, holding technical expertise, employing staff including customer relationship management and developing appropriate market platforms directly or via partners. ECAS will hold all necessary regulatory licences in order to trade flexibility and access markets.

At a local level, voluntary or semi-voluntary local groups with geographical exclusivity, act as sales or managing agents for the ECAS service. They identify local needs, establish trusted local partnerships and oversee the installation of appropriate flexible load technologies and/or Aggregator enabling tools such as HEMS/CADs. They benefit from close relationships with 'Early Adopter' members, householders motivated to take action to reduce their carbon impact and more likely to install low carbon technologies such as EVs, batteries etc.

Local groups are resourced through a combination of mechanisms such as finder's fees, taking direct contracting roles in the installation of technologies or acting as an Energy Services Company (ESCO). Despite this, for regulatory reasons and in order to simplify risk positions, contractual relationships are likely to be established directly between ECAS and householders.

To strengthen the link between local groups and ECAS and provide accountability, transparency and democratic control, some kind of ownership and/or governance relationship might exist between local groups and ECAS eg via a federation or social franchise. In effect, local Community Energy groups would be members of ECAS with voting and control rights.

Key elements of the ECAS model:

- ECAS acts as a trusted intermediary.
- ECAS contracts with householders and energy system actors ie DSOs.
- Staff, resources and technology held by ECAS
- Local groups incentivised via finder's fees and other mechanisms.
- Model benefits from economies of scale AND very local, trusted focus.

2.3.2 ECAS Relationships

As outlined in WP3, section 3.6, commercial arrangements could involve a number of different interactions between energy system parties. Scenarios might include:

(A) Community/Domestic DERs ❺❼ ECAS ❺❼ DSO

(B) Community/Domestic DERs ❺❼ ECAS ❺❼ Commercial Aggregator ❺❼ DSO

(C) Community/Domestic DERs ❺❼ ECAS ❺❼ Market platform ❺❼ DSO

(D) Community/Domestic DERs ❺❼ ECAS ❺❼ Commercial Aggregator ❺❼ Market platform ❺❼ DSO

The strength/weakness of these approaches will depend on a number of future market factors and roles played by ECAS covering: Subscription, Aggregation, Register and bid, Dispatch, Verification and Settlement.

In order to capture as much value as is available within local flexibility markets, short procurement chains will be preferred. As such, as possible ECAS should seek to own, develop and control its tools, technologies and resources.

2.4 Finances

Income
The market for flexibility is examined in greater detail in WP3. For now, it is not possible to make accurate estimates on the value of flexibility other than to estimate margins are likely to be tight with an emphasis on scale and value stacking.

In this context we don't anticipate that local groups will generate sufficient income from flexibility to establish independent businesses based on local flexibility income. Instead, viable scale is likely to lie in the regional, national or pan-European scale.

Local groups might derive income from finder's fees, or the ability for householders to access flexibility income via ECAS, might complement local group's other income generating activity, with the best fit coming around energy efficiency services, in particular deep retrofit, creating a non-financial benefit for local groups to participate in ECAS.

Expenditure
Areas of expenditure for ECAS include:

- Ongoing staff costs
- Upfront capital costs associated with setting up a DRMS (Demand Response Management System)
- Costs of supplying and installing HEMS/CAD in each property
- Upfront and ongoing costs associated with accessing the Smart Meter DCC
- Should if be necessary, upfront and ongoing costs associated with becoming a Balance Responsible Party.

ECAS has a range of possible householder arrangements that could be offered with a variety of advantages and disadvantages. For more detail see WP3, Section 6.

Arrangement	Pros	Cons
Fixed subscription fee *Domestic users pay an annual or monthly fee to ECAS for access to their DER assets, and user retains 100% of DSO income*	Guaranteed income to ECAS, removes risk to ECAS model	Risk of low or no income to user from either limited DSO calls or regular failure to respond.
Agreed percentage of income *ECAS and domestic users share DSO income*	Fair and equitable approach Proportion could be openly calculated to cover costs/ margin for ECAS in their role	Uncertain income to both parties
ECAS fixed annual payment *ECAS pays an annual or monthly payment to user, ECAS retains 100% of DSO income*	Guaranteed income to user, removes risk to them and could increases the potential to recruit participants	Risk of low or no income to ECAS from either limited DSO calls or regular failure to respond.

Table 3: High level ECAS commercial arrangement considerations

2.5 Governance assessment

The ECAS governance structure needs to:

- Ensure compliance with any regulatory conditions to ensure market participation.
- Offer a 'trusted' Community Energy status.
- Be flexible enough to enable a federated, consortia or tiered form of membership for local groups.

As such, only corporate forms that enable 'social enterprise' status and collective ownership have been considered.

Form	Market Compliant?	Community Energy status?	Tiered membership
Community Benefit Society/Multi Stakeholder Co-op (BenCom)	Yes	Yes: Asset Lock	Yes
Co-operative Society (Co-op)	Yes	Yes: Co-operative status	Yes
Community Interest Company (CIC)	Yes	Yes: Asset Lock	Yes
Company Limited By Guarantee (CLG)	Yes	Yes: including not for profit status, co-operative objects	Yes - as a consortia
Charitable Incorporated Organisation (CIO)	Probably precluded by Charitable Objects	Rare	No

Table 4: Governance assessment of ECAS corporate forms

As such, all forms reviewed other than CIO could be viable governance models for ECAS.
A multi-stakeholder co-operative opens up the potential for a further class of members: individual householders, increasing further levels of trust and involvement though the governance management implications of such a model would need careful consideration. Multi-stakeholder co-operatives are also one of the corporate forms able to raise capital via Community Share issues.

2.6 Competition

In a fast developing but still future market it is hard to assess competitors, but an interim assessment can be made.

- Large technology companies, ie Google/Amazon
- Existing Commercial/Industrial Aggregators (see WP3)
- Existing and future energy suppliers.
- Equipment manufacturers (e.g. car / battery producers).
- Local Authorities.

2.6.1 Stakeholder identification

Name	Power/Influence	Support/Attitude
UK Government	High. ECAS is potentially dependent on regulatory and legal changes. Policy support for smart energy is also important, such as mandating standards and providing innovation and business support.	Positive. Supportive of smart energy initiatives. Could do more to accelerate smart meter rollout and pressure suppliers to support opening smart meter systems to third party service providers.
Ofgem/Regulator	High. ECAS is potentially dependent on certain regulatory changes as well as the consistent application of existing policy.	Positive. Has been slow to support development of local energy markets, but has granted derogations for trials and created a ‘regulatory sandbox’ for market innovation.
EU	Medium. Depends on UK involvement in European Energy markets after leaving the EU.	Positive. Support for ‘local energy communities’ in latest Directive, although unclear how this relates to local energy markets.
National Grid/ESO	The ESO is a potential flexibility customer and is also currently in charge of overseeing various national flexibility markets.	Positive. Is taking steps to consolidate flexibility markets under control and lower barriers to entry.
DNO/DSO	High. DNOs are potential customers for ECAS. How they procure services will have a big impact on early flexibility markets.	Positive. DNOs have begun procuring flexibility. Several different approaches to this have already emerged, some of which are quite limited in their vision for the role of DER and flexibility provision.
Suppliers	Medium. Under the supplier hub model suppliers are currently in a privileged position in terms of access to domestic consumers.	Neutral. Suppliers are currently best positioned to procure domestic flexibility and have access to wholesale/BM markets so are potential competitors. They are also potential customers as they may wish to purchase flexibility to minimise portfolio risk.

Commercial and Industrial Aggregators	Low. Have not currently made inroads into domestic and SME sector. Not currently an effective lobby and have suffered due to overexposure to various changes in last decade.	Neutral. Likely competitors. Possible partners or suppliers in some scenarios.
Market/Platform Providers	Low. Many start-ups and new businesses, market still small and in flux.	Neutral. Potential competitors to ECAS, but also more likely to be suppliers of services/systems than Aggregators.
Prosumers.	High. The interest and support of prosumers is essential to the ECAS business model.	Positive. The customers/clients/members of ECAS and its member organisations.
Aggregator Platform Providers	Low. Current nascent platforms unlikely to resemble future systems.	Neutral. Potential suppliers but ECAS could develop own system.
Community Energy Organisations	High. ECAS is orientated towards supporting local and community energy schemes.	Positive. Possible partners/members of ECAS. Community energy groups have shown a lot of interest in participating in flexibility markets.
Housing associations	Medium. Maybe important customers in early stages in order to secure large enough volumes for participation in markets.	Neutral. Possible customers/partners/members of ECAS.
System Integrators	Low.	Positive.
DER Manufacturers/Suppliers	Medium.	Neutral.

Table 5: ECAS stakeholder analysis

2.7 Open Source approach

As outlined in WP4, the favoured technology development route for ECAS is via the use and integration of open source software. The choice for open source tools and components is both ethical and pragmatic conferring a clear competitive advantage.

Open Source is a form of software in which source code is released under a license that copyright holders grant users the rights to study, change, and distribute the software to anyone and for any purpose.

Open Source software is often developed in a collaborative, distributed and public manner. Such software creates a strong value proposition and competitive advantage as compared to proprietary formats, of particular interest as deployed in an energy system context:

- More secure software, more robust and less prone to attack,
- Cheaper software with reduced development and operation costs
- More open and transparent systems - important in public infrastructure context
- Increased interoperability benefiting from integration with multiple other systems

Additionally, a focus on low cost and minimum viable products (MVP) tends towards the participation of innovative, agile and investive start-ups and SMEs as well as 'disruptive' new entrants, challenging incumbents and sector monopolies.

Open source business models tend to focus less on protection of Intellectual Property and instead on development expertise, consultancy services and consumer service provision.

There are multiple examples of open source software and open source systems gaining a competitive advantage within a technology sector and in time displacing proprietary incumbents.

Such examples exist within:

- Internet browsers - the displacement of Microsoft Internet Explorer by Google Chrome and Mozilla Firefox.
- Phone operating systems - e.g. Android (Linux).
- Cloud computing - Linux based servers and systems.

The sector is not limited to software and there are examples of Open hardware including Raspberry Pi computers. Partners Megni deploy both Open Source hardware and software in their OpenEnergyMonitor and EmonCMS products.

Energy system actor	**Benefits of Open Source**
Regulators	Discourages monopoly reducing costs, benefits consumers.
DSOs	Enables greater choice of Aggregator
Technology providers	Promotes innovation for start-ups, encourages MVP development, community support, quicker development, low development costs, lower barriers to entry, greater longevity of software
Aggregator	Lowers entry barriers for new entrants, increased interoperability for novel technologies and services.
Customers	Lower consumer costs and/or higher incentives, more secure.

Table 5: assessment of open source benefits to energy system actors

2.8 Conclusion

The nature of local flexibility markets suggests the creation of a federated energy system Aggregator intermediary which achieves both scale and a locally specific focus, has a great deal of potential. The Community Energy sector has a number of strengths and opportunities that could be taken advantage of by such a model. Further research and piloting is required to assess the value of flexibility that could be exploited by ECAS and to build a fully operational business plan.

3 WP3: DSO Flexibility Market Overview

Author: Ray Arrell, Regen

3.1 Background

The UK energy system is undergoing a significant change, through the decentralisation and decarbonisation of electricity generation as well as a shift towards the electrification of both heat and transport. This shift to low carbon technologies that now provide significant contributions to UK energy[4], brings a number of operational challenges for both the national Electricity System Operator (ESO) and regional Distribution Network Operators (DNOs).

The ESO is under pressure to keep the lights on and manage an evolving generation supply mix. Other shift changes in UK energy also create a number of challenges for the ESO, namely:

- Increased intermittent and distributed generation
- Evolving electricity demand patterns and overall growth of demand
- System capacity margins becoming more complicated to forecast

The regional DNOs are also challenged to unlock constrained network areas and open up new capacity, whilst deferring/avoiding high cost options such as network reinforcement and grappling with the transition to their new, more dynamic roles as Distribution System Operators (DSOs)[5].

The need to bring and operate flexibility into the energy system is therefore greater than ever before. The ESO have responded to this by developing markets for national balancing services[6] over the past few years, paying flexibility providers to participate in programmes such as Short Term Operating Reserve (STOR), Firm Frequency Response (FFR) or Demand Turn-Up. The development of these markets has driven a lot of activity in the sector, often being seen as an additional source of income for generators, storage operators and large energy users to target, alongside their existing revenue streams.

As part of the transition to DSO, Ofgem has stipulated the development of the market for flexibility services within regional network areas. Often described as 'local flexibility markets', these markets are in their infancy and DNOs are currently testing the waters, through publishing strategy papers and industry consultations[7], developing trial projects and trading platforms[8] or issuing calls for expressions of interest (EOI) and tenders[9].

The development of local flexibility markets potentially brings opportunities for the DSO, as a procurer of flexibility, to engage more directly with their connected customers and for providers of flexibility with smaller entry thresholds. In short, localised network constraints being addressed by local assets, contracting with their local network operators. Different providers of flexibility may be able to participate in these local markets in different ways, but community and domestic level flexibility resources are a potentially significant and untapped opportunity.

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[4] Wind power overtook nuclear energy in the UK for the first time in first quarter of 2018 for example, second only to gas fired generation, see article: https://www.independent.co.uk/environment/wind-power-overtakes-nuclear-uk-renewable-energy-climate-change-a8353686.html

[5] See Energy Networks Association 'Open Networks' project, work stream 3 'DSO Transition': http://www.energynetworks.org/electricity/futures/open-networks-project/open-networks-project-workstream-products.html/ws3-dso-transistion.html

[6] See National Grid balancing services: https://www.nationalgrid.com/uk/electricity/balancing-services

[7] See WPD "Signposting of distribution system needs" consultation, May 2018: https://www.westernpower.co.uk/About-us/Our-Business/Our-network/Strategic-network-investment/Signposting.aspx

[8] See Regen's map of local flexibility DSO trials and live projects, April 2018: https://www.linkedin.com/pulse/part-1-local-flexibility-trials-merlin-hyman/

[9] See example of Electricity North West (ENW)'s expression of interest for flexible services, April 2018: https://www.enwl.co.uk/innovation/our-approach/flexible-services/

This section of the report seeks to identify potential sources of value and income from DSO led flexibility markets, review similar approaches in other countries and identify the role of the Aggregator in the local flexibility space.

3.2 DSO transition strategy – considerations for ECAS

The transition to DSO is one of the biggest changes and areas of activity in the sector. Some of the most direct work in this area is under the **Open Networks** project coordinated by the ENA[10], exploring a number of work streams to establish how a DSO is defined (see Figure 1) and what the transition actually means for customers, for DNOs in their current roles and for the wider UK energy system.

Figure 1: ENA Open Networks DSO definition (June 2017)

> *"A Distribution System Operator (DSO) securely operates and develops an active distribution system comprising networks, demand, generation and other flexible distributed energy resources (DER).*
>
> *As a neutral facilitator of an open and accessible market, it will enable competitive access to markets and the optimal use of DER on distribution networks to deliver security, sustainability and affordability in the support of whole system optimisation.*
>
> *A DSO enable customers to be both producers and consumers; enabling customer access, customer choice and great customer service."*
>
> **ENA Open Networks, Work Stream 3 - DSO Transition, Product 1 a) DSO Definition**

Each of the UK DNOs have published a strategy paper that outlines their view of how they plan to transition to take on the role of DSO, a summary of which is captured in Table 1.

Table 1: DSO strategies - emerging principles from DNOs

DNO	DSO Transition Strategy Principles
electricity north west Bringing energy to your door [See: ENW DSO website]	• Network capacity provision • Network capacity market management • Network access management and forecasting • Service definition and charging • Wider market engagement
NORTHERN POWERGRID [See: NPG innovation site]	• Delivering further innovation projects to understand the transition to a flexible system • Seek more opportunities to buy and sell storage and Demand Side Response (DSR) • Deploy further Active Network Management (ANM)[11] areas
SP ENERGY NETWORKS [See: SPEN DSO vision]	• Rollout and extend the use of ANM to manage network constraints • Prioritise areas which are likely to benefit from the DSO model • Expand network monitoring to future proof legacy assets • Model and investigate ancillary services market and identify cost effective solutions • Put in place commercial arrangements with National Grid and DER providers within DSO trial areas

[10] See ENA Open Networks project portal: http://www.energynetworks.org/electricity/futures/open-networks-project/open-networks-project-overview/

[11] See ENA definition of ANM: https://uksmartgrid.org/wp-content/uploads/2015/07/ENA-GPG-Public-event-slides-v1_0-2.pdf

Scottish & Southern Electricity Networks [See: SSEN DSO Transition report]	• Greater choice and opportunity for customers, whilst ensuring the service remains reliable, efficient and resilient • Integrating learning from innovation projects • Neutral facilitation of local and national markets to unlock local solutions, by identifying and providing visibility to allow markets to function and trade energy throughout the network
UK Power Networks [See: UKPN FutureSmart]	• Facilitate cheaper and quicker connections using proven innovation • Use customer flexibility as an alternative to network upgrades • Develop enhanced System Operator capabilities • Collaborate with industry to enable GB wide benefits • Prepare and facilitate the uptake of Electric Vehicles (EVs)
WESTERN POWER DISTRIBUTION *Serving the Midlands, South West and Wales* [See: WPD DSO Strategy]	• Level playing field access for all customers • Maximisation of accessibility to services for vulnerable customers • Efficient and economic whole system outcomes • Facilitation of neutral markets • Provision of services where no market actor exists • Using flexibility services to deliver quicker, more efficient and cheaper connections • Deliver maximum value to individual customers offering network provided flexibility services and all customers through optimised use of smart grid flexibility • Environmental benefits through minimisation of losses

Some key themes for the transition to DSO are therefore:

- **Enabling cheaper, quicker connections for customers**
- **Creation of a level playing field for customers and neutral markets (i.e. technology or approach agnostic)**
- **Enabling and neutrally facilitating local flexibility services, to mitigate network constraints**
- **Increase the use of ANM**

DNOs are unified in an intention to facilitate markets and create an environment where flexibility services can be procured. Flexibility can assist them in unlocking network capacity and to manage network constraints/events, as an alternative to costly network reinforcement (see Figure 2).

Figure 2: Benefits of local flexibility services for DSOs

How these markets are to be operated, who can participate in them and how they can secure value from them, are key questions that are yet to be fully addressed. Local flexibility is an emergent market and when comparing it to national balancing services, for example, some clear distinctions can be made.

The ESO will call on assets to respond to system-wide conditions such as:

- Deviations in grid frequency, addressed through programmes like FFR
- The need for energy reserve to address a falloff in system-wide capacity, addressed through programmes like the Capacity Market or STOR

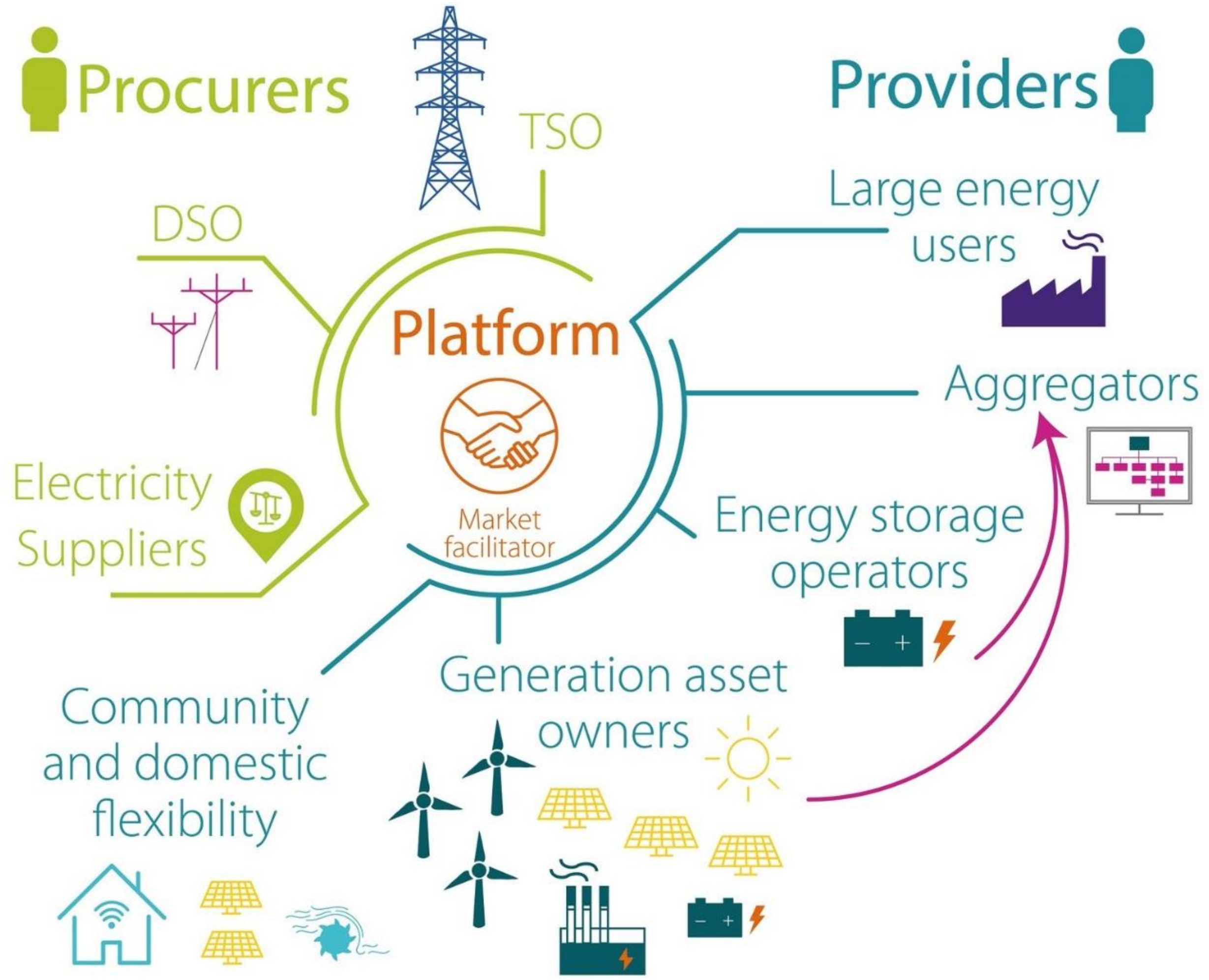
The location of the assets active in these markets is largely irrelevant.

With local flexibility markets however, the need for your local DSO to call on a local response, to local network issues, brings a new dynamic to matching solutions to needs. The calls for flexibility will therefore be centred around specific distribution network areas or even individual constrained substations. These are often referred to as Constraint Managed Zones (CMZs).

In a series of infographic led blogs that Regen produced in the spring[12], community and domestic flexibility was identified as one of five main 'classes' of flexibility service providers, alongside large energy users, generation asset owners, energy storage providers and Aggregators.

An open and easily accessible platform to enable DSOs to procure flexibility for their own operational needs, is vital to enable DNOs to meet their regulatory obligations; to act as a neutral market facilitator.

[12] See Regen blog series 'Development of local flexibility markets in five steps': Launch | Part 1 | Part 2 | Part 3 | Part 4 | Part 5



Understanding how domestic scale flexibility can actively participate in local markets, is a key objective of this feasibility study. Noting the relative position of community and domestic flexibility alongside competitors, is an important consideration for the ECAS model. These competitors include:

i) **Large and medium scale flexible distributed generation**
ii) **Industrial energy users with flexible demand controls on-site**
iii) **Standalone distributed energy storage assets**

These parties are all poised and ready to bid in to local flex markets. An ECAS model must therefore consider some of the technical challenges and barriers to household flexibility competing, including:

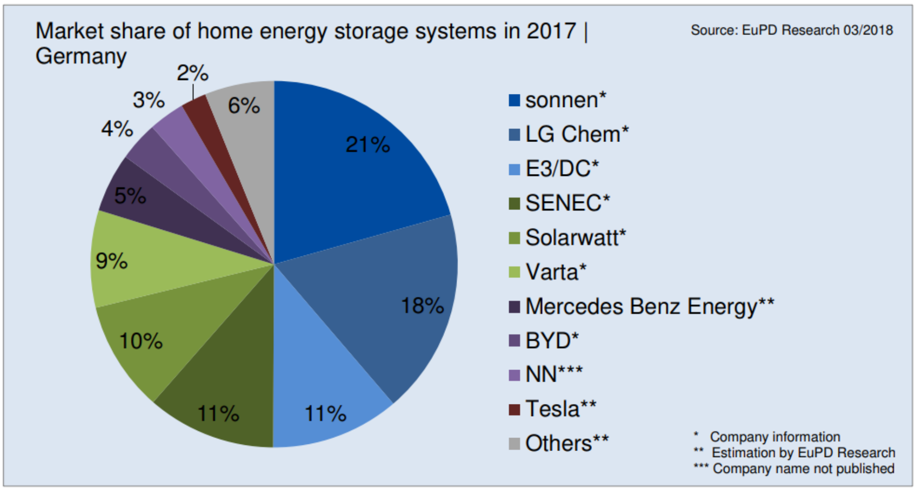
- The inherent dilution of value through aggregation vs flexibility parties that can contract directly
- Understanding what firm, controllable and flexible load is reliably accessible in the home
- The need for verification of domestic responses, requiring a greater coverage of smart meters, or a potentially costly proprietary control and communications device in each home
- The need for automatic switching of household loads vs the need to rely on manual response

Domestic flexibility in the UK is set to become more apparent and dispatchable, drivers include:

- The forecast growth of EVs[13]
- The electrification of heat through a proliferation of heat pumps[14]
- Uptake of domestic storage[15] and the range of home battery products available, see Figure 3

Figure 3: European battery product manufacturers - market share

Source and credit: EuPD 'European Residential PV Energy Storage Market Overview 2017', see: https://www.eupd-research.com/fileadmin/content/download/pdf/Produkte_Technologische_Nachhaltigkeit/EuPD_Research_European_Residential_PV_Energy_Storage_Market_Overview_2017.pdf



Additional sources for flexibility in the home might include increased use of smart appliances[16], such as washing machines, refrigerators, water heaters, HVAC and boilers.

Though it is evident that despite baseline progress[17], the rollout of residential smart meters in the UK will need to be significantly accelerated to not only hit government targets, but to enable the verification of dispatching domestic flexibility in response to local (or national) calls.

3.3 Local flexibility services – market activity and trials

Many of the DNOs have begun to implement their strategies referenced in Table 1, kicking off innovation funded trials, commissioning the development of trading platforms, see Figure 4 for examples.

[13] Regen's future growth modelling, Committee on Climate Change (CCC) projections and National Grid's 2017 Future Energy Scenarios (FES) Two Degrees scenario, show a range between 10-13million EVs sold by 2035, see Regen's Harnessing the Electric Vehicle Revolution report, page 9: https://www.regensw.co.uk/Handlers/Download.ashx?IDMF=c2c53763-2f7f-4d70-96d3-aed4290c9021

[14] National Grid FES 2017 forecasts a 68% reduction in gas fired heating by 2050, predominantly replaced with heat pumps. See FES 2017 report, Section 3.3 key insights (page 32): http://fes.nationalgrid.com/media/1253/final-fes-2017-updated-interactive-pdf-44-amended.pdf

[15] REA data in 2016 showed at least 1,500 residential storage deployments had occurred as of Oct 2016, see: https://www.r-e-a.net/images/upload/news_415_REA_-_Energy_Storage_in_the_UK_Report_2016_Update.pdf

[16] See *European Commission Preparatory Study on Smart Appliances*: http://www.eco-smartappliances.eu/Pages/welcome.aspx

[17] Which? analysis from Feb 2018 showed there to be over 8 million smart meters now in homes, see: https://www.which.co.uk/news/2018/02/smart-meter-2020-target-will-energy-companies-meet-it/

Figure 4: Map of DSO trials and projects

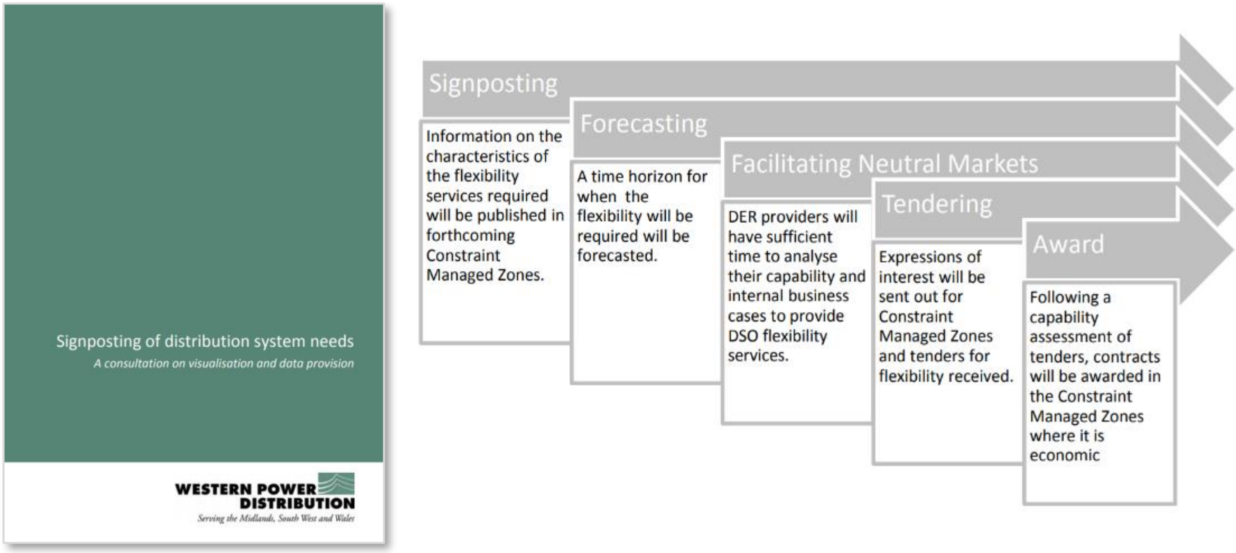
Some DNOs are taking more direct action through instigating 'business as usual' signposting and live procurement processes for flexibility services in some licence areas. A summary of some of the key activities under each of these DNOs, is summarised in the following pages.

3.3.1 Western Power Distribution

3.3.1.1 Signposting

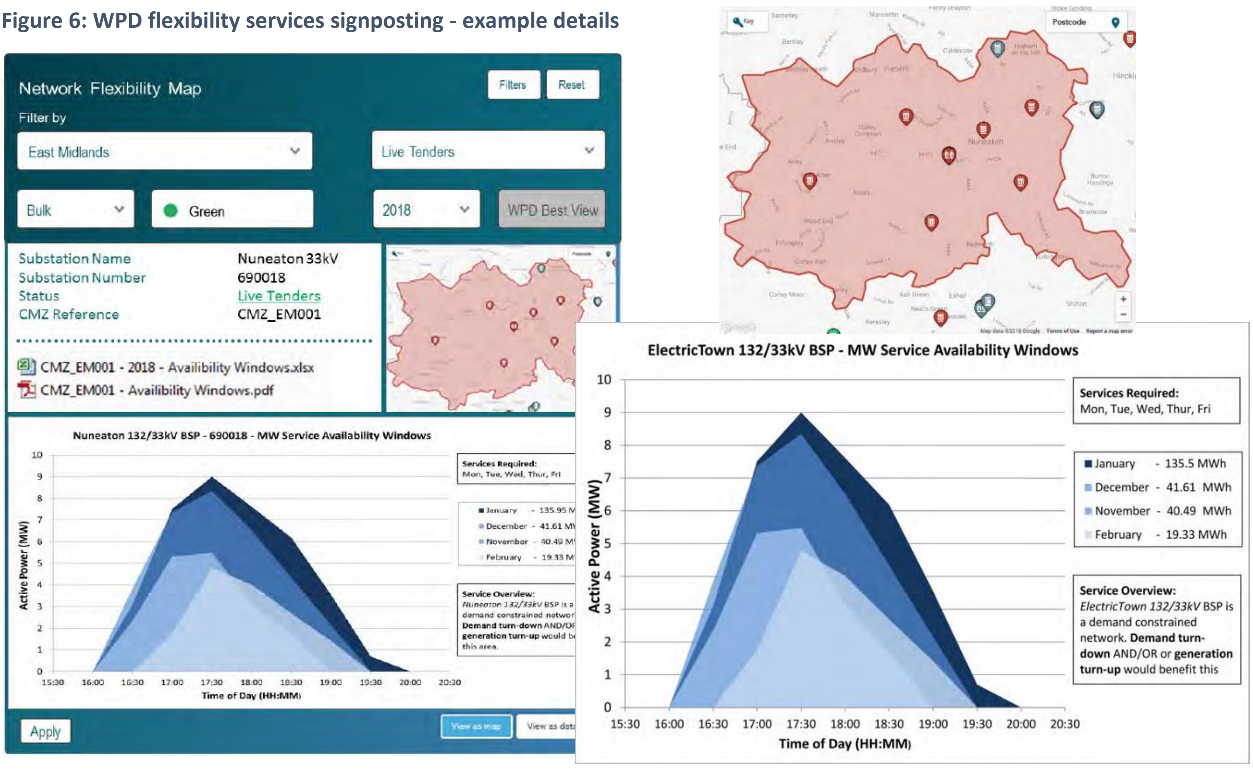
Through a consultation published in April 2018 (see Figure 5), WPD sought views on how best to collaborate with stakeholders, to develop a method of communicating and conveying needs for flexibility services to a wide range of potential providers.

Figure 5: WPD signposting consultation, May 2018
See: https://www.westernpower.co.uk/About-us/Our-Business/Our-network/Strategic-network-investment/Signposting.aspx



WPD proposed that the information provided should detail the capacity (MW), the months and availability windows required and attempt to predict the volume of energy required in MWh in a given month. It was noted that the 'signposted' energy volume might differ from the volume put out to tender. An example of the type of information that would be signposted is shown in Figure 6.

Figure 6: WPD flexibility services signposting - example details



Flexibility providers and Aggregators can use this information to coordinate portfolios of generation, storage and DSR assets, to meet these future requirements.

With regards to revenue stacking, WPD indicated that providers will not be required to exclusively be available for WPD, when their services are not required. This potentially paves the way for participants to enter into multiple contracts, i.e. with WPD and with the ESO national balancing services.

The consultation therefore sought views on:

- If "Signposting" accurately describes the information and process proposed
- If it would be useful to use signposting across the network or just in current constrained areas
- If signposting long term distribution requirements should be issued ahead of a tender
- Using scenario modelling to predict a number of potential outlooks for future system requirements would be sensible
- If further caveats or explanatory material should be provided, to describe to what extent the signposting information can be relied upon to make business or investment decisions
- The proposed method of displaying information is clear and doesn't miss anything important
- If the Information could be presented in a more useful way
- The proposed method to define the geographical boundary is sufficient
- An interactive mapping tool, that displays signposting information and live tenders, would be used by stakeholders
- Whether raw data should also be made available
- It is desirable to have system requirements for multiple compatible services simplified into regional system requirements
- DSO services are stackable with other revenue streams
- WPD not enforcing exclusivity is agreeable and if there are other services that do enforce exclusivity, that may affect the ability to engage with WPD's flexibility services

WPD has developed its flexibility services in line with the reserve products procured by the SO. Calls for EOIs would be declared through an online platform, allowing participants to submit their availability schedules. WPD propose to then provide confirmation at noon on Thursday the week ahead of the window of operation, which would then run from Monday through to Sunday. This consultation closed on the 18th May.

3.3.1.2 Flexible Power campaign

WPD's signposting consultation builds on a trial in WPD's Midlands licence areas (under Project ENTIRE[18]) in 2017, where WPD sought to determine the potential flexibility services that could be provided within 14 stated CMZs in the Midlands.

WPD are advertising flexibility needs under their **Flexible Power**[19] brand, predominantly seeking businesses to reduce consumption or increase on-site generation, for at least 2 hours, in response to an automated signal. Flexibility responses required by WPD have been categorised into three types of service: **Secure**, **Dynamic** and **Restore**. Table 2 provides an overview of these.

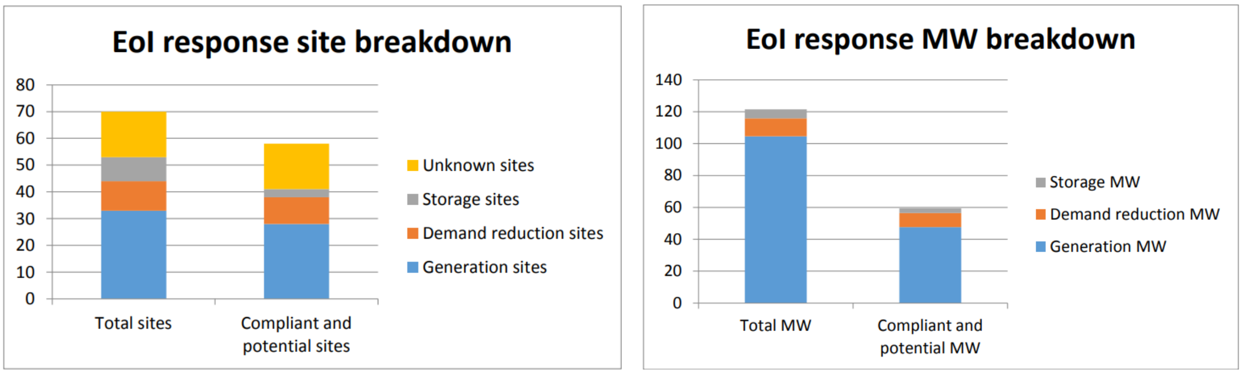
Table 2: WPD Flexible Power service categories for businesses (2017)

Service	Description	Requirement	Dispatch	Payment Structure
Secure	Used to manage peak demand loading on the network and pre-emptively reduce network loading.	Largely required on weekday evenings, all year round	**Declaration:** Week ahead (Thursday for the following Monday) **Dispatch notice:** Week ahead notification of need and 15min signal	**i) Arming Fee:** Credited when the service is scheduled **ii) Utilisation Fee:** Awarded when flex service is delivered
Dynamic	Used to support the network in the event of specific fault conditions	Largely required during maintenance periods, likely through British Summer Time	**Declaration:** Week ahead (Thursday for the following Monday) **Dispatch notice:** 15 minutes	**i) Availability Fee:** Credited when availability is accepted **ii) Utilisation Fee:** Awarded when flex service is delivered
Restore	Used to help with restoration following rare fault conditions, reducing stress on the network	Unplanned fault conditions are rare and largely in the event of equipment failure	**Declaration:** Week ahead (Thursday for the following Monday) **Dispatch notice:** 15 minutes	**i) Utilisation Fee only:** Premium reward for response that aids network restoration, awarded when flex service is delivered.

The 2017 EOI[20] closed to responses on 15 December 2017, with 70 sites totalling 121 MW of capacity responding. Energy generation uplift and demand reduction dominated responses, with energy storage also featuring (5% of responding capacity). Only 34 sites (41 MW) were fully compliant with some responding sites either being unknown, yet to be built or not supplying sufficient information, see breakdown of results
Figure 7.

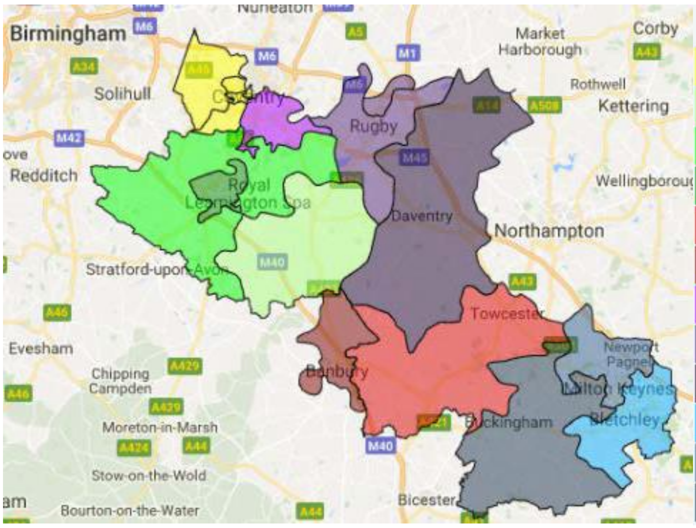
[18] See project summary page: https://www.westernpower.co.uk/Innovation/Projects/Current-Projects/Project-ENTIRE.aspx
[19] See Flexible Power campaign website: http://www.flexiblepower.co.uk/
[20] See 2017 Midlands trial EOI results: http://www.flexiblepower.co.uk/FlexiblePower/media/Documents/EOI-results.pdf

Figure 7: WPD Flexible Power 2017 EOI responses summary
(source and credit: http://www.flexiblepower.co.uk/FlexiblePower/media/Documents/EOI-results.pdf)



The results from the 2017 Midlands EOI show that 12 of the 14 identified CMZs are to be taken forward to the next stages of the flexibility procurement process, likely to be the signposting → forecasting → market tendering and contractual award of services. Figure 8 details the geographic areas of the 12 CMZs being taken forward, with Coventry Central and Pailton being omitted.

Figure 8: WPD Flexible Power - CMZs being taken forward from 2017 EOI and types of service provision



Colour	Zone	Name	Services
	1.1	Coventry Interconnector	Secure & Restore
	2.1	Harbury	Dynamic & Restore
	2.2	Warwick 33kV	Dynamic & Restore
	2.3	Warwick 11kV	Dynamic & Restore
	3.1	Brackley	Dynamic & Restore
	3.2	Banbury	Dynamic & Restore
	4.1	Whitley	Secure & Restore
	4.2	Rugby	Secure & Restore
	4.4	Daventry	Secure & Restore
	5.1	Bletchley	Secure & Restore
	5.2	Bradwell Abbey	Secure & Restore
	5.3	Stony Stratford	Secure & Restore

3.3.1.3 2018 call for EOIs

A further live EOI[21] was published by WPD in May 2018, for five additional constraint areas containing 18 new CMZs. This EOI followed a similar format with flexibility provider sites needing to meet the following requirements:

- Must be within one of the identified zones
- Must be half hourly metered
- Must have minute by minute metering
- Must be able to meet the 15-minute dispatch signal and respond
- Must be able to sustain response for at least 2 hours

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[21] See live 2018 EOI document: http://www.flexiblepower.co.uk/FlexiblePower/media/Documents/Winter-2018-Summer-2019-EOI-Document.pdf

- Must be built or have a connection agreement with final milestone, before the end of procurement
- Provision of the flexibility service must not cause the participant to breach other agreements (e.g. their own connection agreement with WPD)

The details of these 18 new zones are outlined in Figure 9 and Table 3.

Figure 9: WPD 2018 EOI - Map of identified constraint areas

Source: WPD EOI document (May 2018)

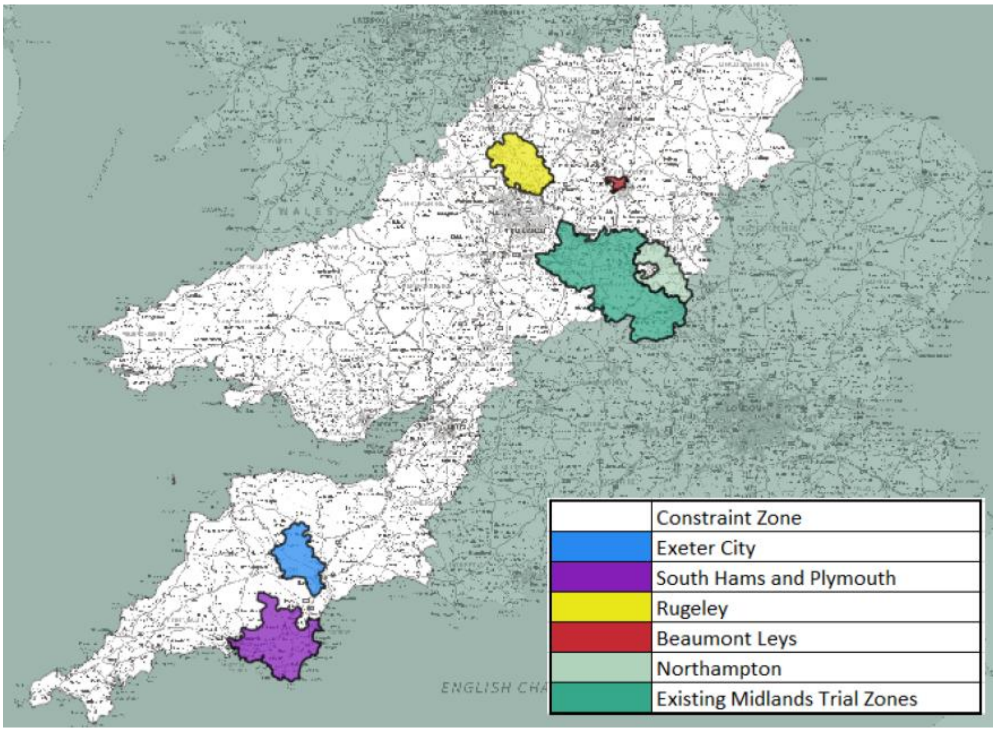


Table 3: WPD 2018 EOI - Details of flexibility requirements

Source: WPD EOI document (May 2018)

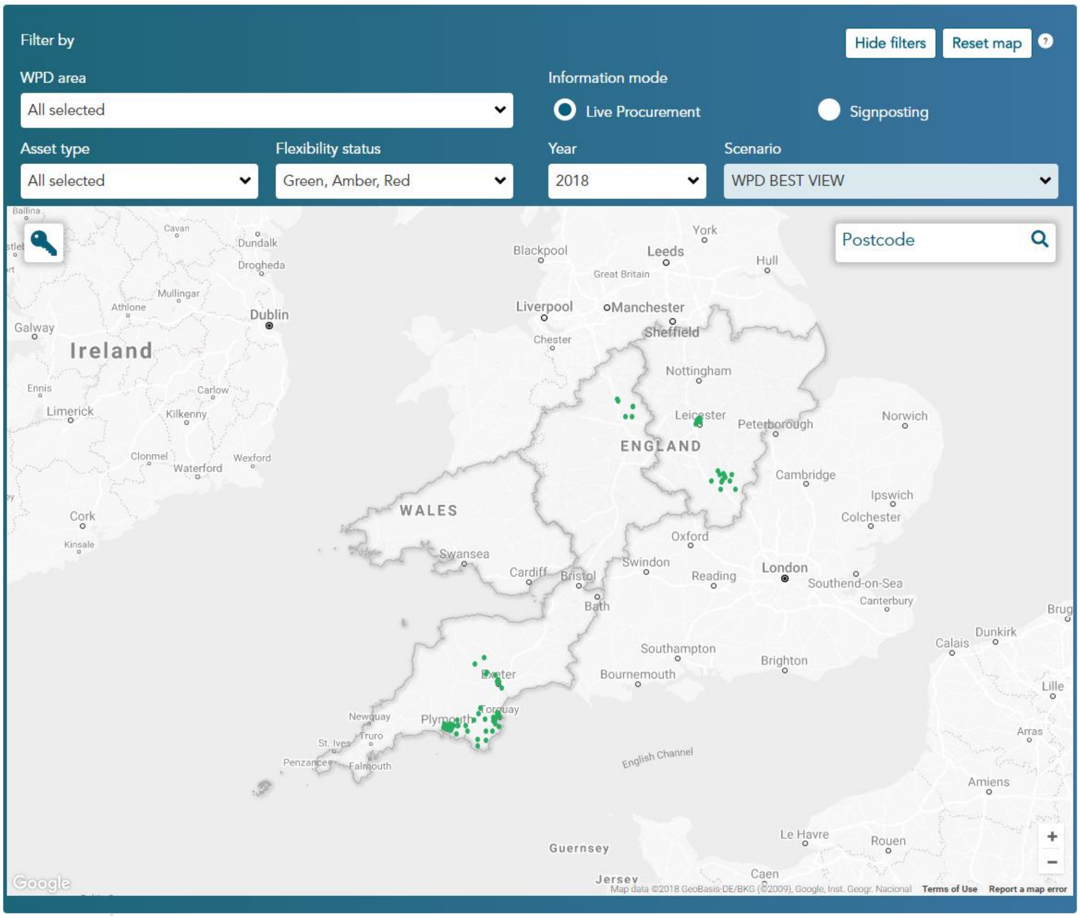
Constraint	Flexibility Zones	Flexibility Service Requirements		
		Flex Service	Days Required	Monthly Requirement
Exeter City	Exeter City	**Dynamic Restore**	Mon – Sat	Jan – 230.66 MWh Feb – 14.66 MWh Nov – 49.64 MWh Dec – 105.2 MWh
South Hams and Plymouth	Plympton Milehouse Plymouth Totnes Paignton Torquay	**Dynamic Restore**	Mon – Fri	May – 471.95 MWh June – 296.16 MWh
Rugeley	Stafford 132 Stafford South Rugeley Town Cannock Burntwood Lichfield	**Secure Restore**	Mon – Sat	Dec – 43.31 MWh

Northampton	Northampton East Northampton West Northampton	**Restore**	*No firm MWh requirements - could be on any day and anytime in the year*	
Beaumont Leys	Beaumont Leys Wider Area	**Secure** **Restore**	Mon – Sat	Jan – 92.96 MWh Feb – 28.21 MWh Nov – 12.89 MWh Dec – 7.07 MWh

3.3.1.4 Network Flexibility Map

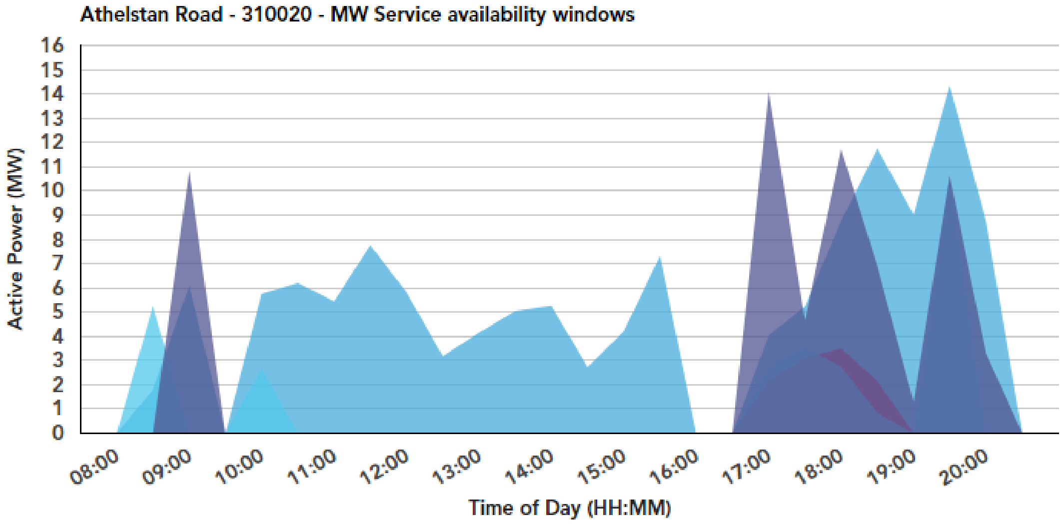
In July 2018, WPD launched an accompanying interactive online mapping service, their Network Flexibility Map. Using the same mapping interface as their Network Capacity Map launched in 2017, the flexibility map (see Figure 10) enables developers and potential providers of services, with an updated view of the flexibility requirements for specific substation areas.

Figure 10: WPD Network Flexibility Map (Source: WPD, 2018)



This map also provides a more granular level of information around the requirements, in addition to the EOI. Users are able to download PDF or spreadsheet versions of monthly flexibility needs, down to half hour settlement periods, see **Figure *11***.

Figure 11: Example of Exeter Flexibility Zone half hourly active power (MW) requirements (Source: WPD, 2018)



3.3.1.5 Payments and payment structure

Financial rewards to participants vary, depending on the type of service and location (I.e. which CMZ). The fixed payments on offer for each service in each zone is summarised in Table 4.

Table 4: WPD 2018 EOI - summary of proposed payments, by constraint area

Constraint	Flexibility Zones	Service	Arming Fee	Availability Fee	Utilisation Fee
Exeter City	Exeter City	Dynamic	--	£5/MW/hour	£300/MWh
		Restore	--	--	£600/MWh
South Hams and Plymouth	Plympton Milehouse Plymouth Totnes Paignton Torquay	Dynamic	--	£5/MW/hour	£300/MWh
		Restore	--	--	£600/MWh
Rugeley	Stafford 132 Stafford South Rugeley Town Cannock Burntwood Lichfield	Secure	£75/MW/hour	--	£150/MWh
		Restore	--	--	£600/MWh
Northampton	Northampton East Northampton West Northampton	Restore	--	--	£600/MWh
Beaumont Leys	Beaumont Leys Wider Area	Secure	£118/MW/hour	--	£150/MWh
		Restore	--	--	£600/MWh
Coventry Interconnector	Coventry	Secure	75/MW/hour	--	£150/MWh
		Restore	--	--	£600/MWh
Harbur and Warwick	Harbury Warwick 33kV Warwick 11kV	Dynamic	--	£5/MW/hour	£300/MWh
		Restore	--	--	£600/MWh
Brackley and Banbury	Brackley Banbury	Dynamic	--	£5/MW/hour	£300/MWh
		Restore	--	--	£600/MWh
Whitley, Rugby and Daventry	Whitley Rugby Daventry	Secure	£118/MW/hour	--	£150/MWh
		Restore	--	--	£600/MWh
Bletchley, Bradwell Abbey and Stony Stratford	Bletchley Bradwell Abbey Stony Stratford	Secure	£118/MW/hour	--	£150/MWh
		Restore	--	--	£600/MWh

Dependent on the type of flexibility service, non-performance from a flexibility provider could be approached in a number of ways. Instances of non-performance might be:

- A lack of response after declaring availability
- Not being able to sustain the service for the full duration (minimum requirement of 2 hours)
- Not ramping up declared capacity quickly enough, or dropping out part way through

For **Dynamic** and **Secure** services, WPD proposes the use of a ‘sliding scale of underperformance’ to enforce a reduced utilisation fee for underperformance. If a provider responds with between 100% and 95% of their capacity they will receive their full payment. Thereafter, for every 1% of under delivery below 95%, they will see a reduction in utilisation payments of 3%. Thus, if a participant delivers 63% (or lower) of their declared capacity, they will receive zero payment. **Restore** services use a 20% grace factor and a similar 2% rachet reduction. There is also the potential for pre-paid availability/arming payments to be clawed back, based on the average energy delivered per event. Based on this method, total average availability and arming payments are then to be reconciled monthly.

3.3.1.6 Baseline

The method by which WPD calculates the baseline, to which flexible capacity demand reduction/ generation turn-up is referenced against, is discussed within a supporting Flexible Power document[22].

For demand reduction:

This determines that on a monthly rolling basis, the baseline capacity will be defined as "*an excerpt from the first three full weeks of the month, between 3pm and 8pm, giving a sample over a total of 75 hours*".

The 5-hour daily consumption is divided by 75 hours to give an average monthly demand, which is then used as the baseline for the following month. This will therefore determine the demand reduction performance payments on a rolling basis.

With the likelihood that dispatches will be relatively infrequent across a given month, WPD do not foresee that the operation of demand reduction services will have a material effect on baselines. However, WPD state that any negative or unfair impacts to a party's baseline will be reviewed and a decision would be made on a discretionary basis.

For generation turn-up:

If a participant has back-up generation, the baseline is likely to be set at zero. This is due to the generator most likely starting offline. For other non-intermittent generation that operates more regularly, an average output would be determined and set as the baseline, so as to establish the level of increased output or 'turn-up capability'.

It will be interesting to see if diesel generators can participate in, when considering impending exhaust emission control stipulations under the Medium Combustion Plant Directive[23].

There are a number of considerations for the ECAS model with regards to setting a baseline, specifically with domestic DER assets/premises falling under the demand category.

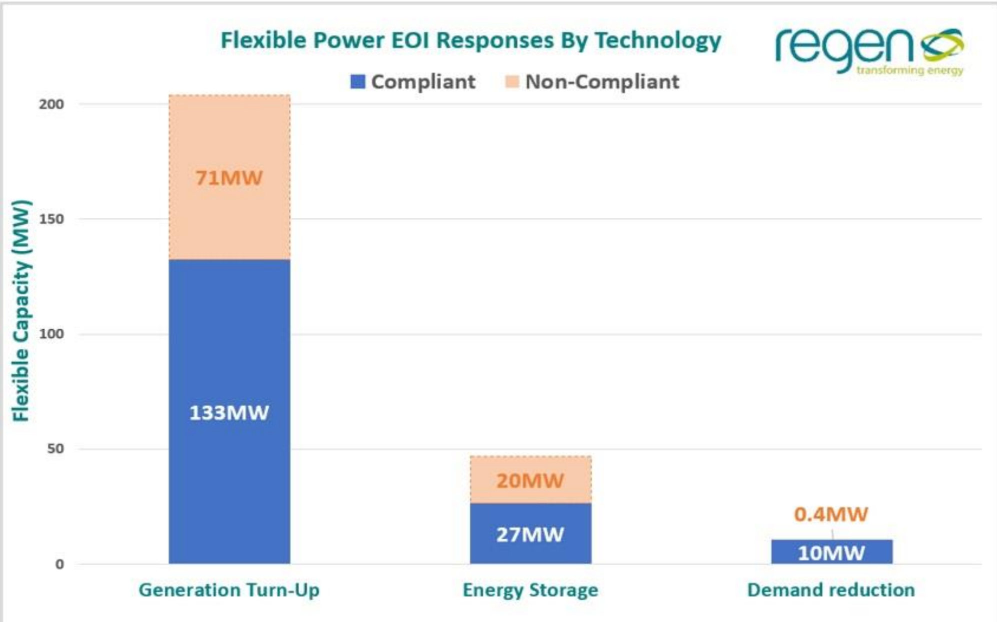
- The 3pm-8pm window acting to inform the baseline may be an advantage, as this may be when the majority of existing peak demand occurs at the domestic level, thus setting a baseline for demand reduction to be fairly high and therefore lucrative.
- The method to determine an average sample baseline is sensible, from the perspective of trying to remove the potential for 'gaming' of utilisation payments, (i.e. by simply ramping up demand just before a likely availability window or similar).
- The flexible assets within a household are likely to be specific individual loads or appliances such as immersion heaters, home batteries of EVs. Therefore, to verify the full demonstrable reduction potential, homeowners may need to increase loads during these sample periods, either for the whole 75 hours or a majority of the daily period. This may result in additional electricity costs to consumers, that may even negate any potential revenue they would receive from responding to flexibility calls. This in itself wipes out any potential business model.
- This is also likely to be an operational challenge or additional cost burden for larger commercial and industrial (C&I) participants, who do not have regimented or predictable demand portfolios.

[22] See Flexible Power CMZ Payment and Contract Assistance Notes: http://www.flexiblepower.co.uk/FlexiblePower/media/Documents/CMZ-payment-and-contract-assistance-notes-MT.pdf
[23] See EU MCP Directive overview: http://ec.europa.eu/environment/industry/stationary/mcp.htm

3.3.1.7 2018 EOI results

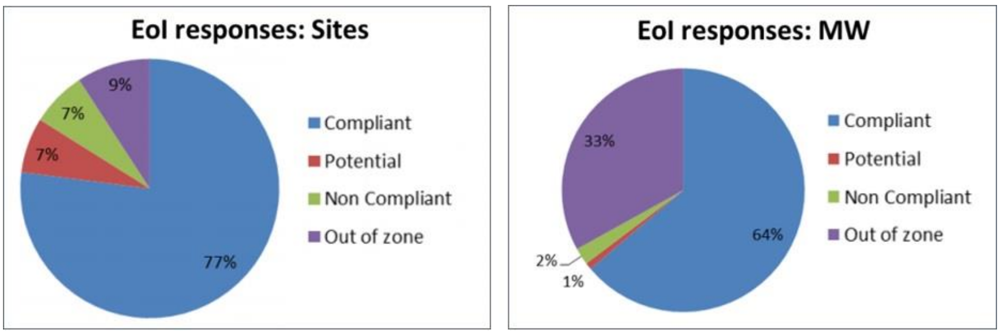
The results of the latest EOI have now been published[24], with WPD announcing an intention to take 16 of the 18 CMZs forward through to tender. The two CMZs in the Beaumont Leys area were removed, potentially related to low or non-compliant responses. The response totalled 87 sites, offering 261 MW of flexibility as a mixture of generation turn-up, demand reduction and energy storage. Only 67 sites (167 MW) were wholly compliant, with 8 sites (86 MW) located outside of the advertised zones and 6 sites (6 MW) classified as 'non-compliant'. From meeting with WPD, compliance potentially relates to factors such as the type of technology, flexible capabilities and the feasibility of a given site to meet the 15-minute response and two-hour duration. See summary by technology in Figure 12.

Figure 12: WPD Flexible Power EOI compliant technology breakdown (credit: Regen)



As Figure 13 outlines, generation turn-up was dominant, with 132.5 MW of the compliant capacity, across 12 sites. Three of the four storage projects (totalling 27 MW) that responded were compliant. Perhaps most pertinent to the ECAS model, in contrast, there were 58 compliant demand reduction sites, but in total only accounted for 10 MW (6%) of the compliant capacity, an average DSR site demand of 172 kW. This suggests that the lower (or non-specific) entry threshold is enabling much smaller demand-side sites and assets to participate in local flexibility.

Figure 13: WPD Flexible Power EOI response summary (source and credit: WPD)



[24] See WPD Flexible Power EOI responses, Aug 2018: https://www.flexiblepower.co.uk/FlexiblePower/media/Documents/EOI-results.pdf

Which projects engage in the follow-on tender process will be interesting to see, as the EOI was purely an exercise in gauging interest. Participants who didn't enter are still able to bid into the tender.

3.3.2 UK Power Networks

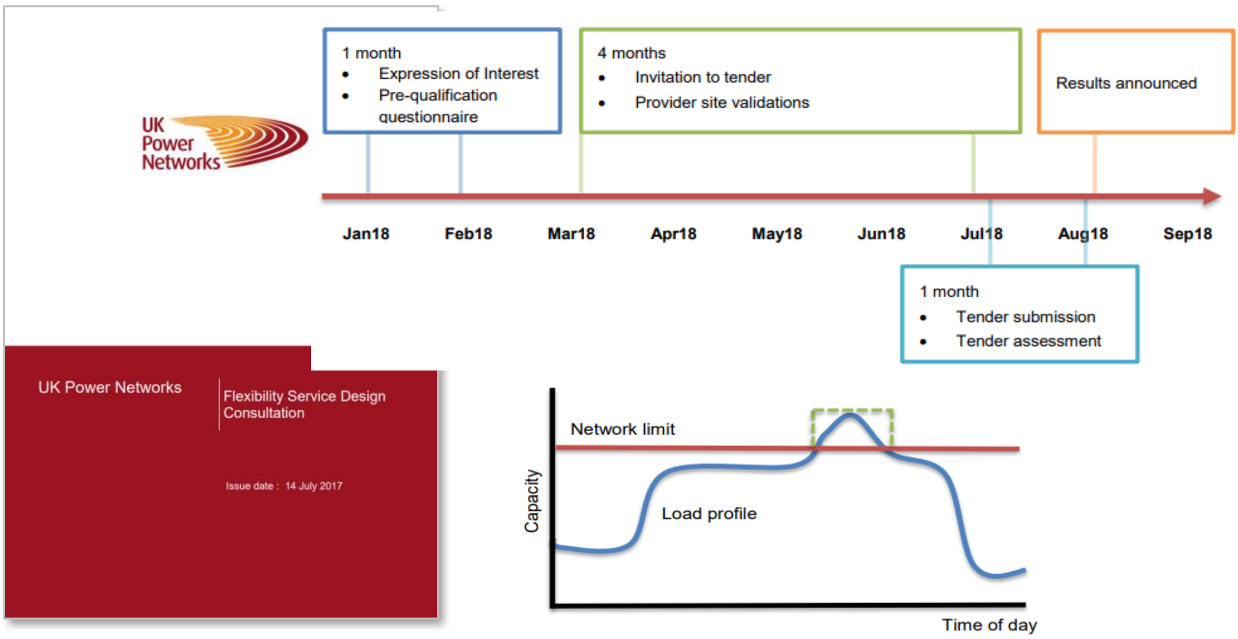
UKPN was one of the first DNOs to declare itself a DSO and to launch a structured consultation and tender process to create a new flexibility market.

The flexibility service design consultation in July 2017 (see Figure 14) outlined UKPN's initial assumptions and approach to procuring flexibility including key elements such as:

- locational requirements
- minimum lead-times and duration
- contract length
- minimum capacity requirements a
- proposed approach to pricing.

As with other DNOs, the flexibility requirements identified were heavily weighted towards meeting demand constraints during peak demand load periods.

Figure 14: UKPN flexibility service design consultation (July 2017)
See: https://www.ukpowernetworks.co.uk/internet/en/have-your-say/documents/UKPN_Flex_Consultation.pdf



With regards to pricing, UKPN outlined their proposals around identifying the best method to value flexibility through a matrix table of high and low availability vs utilisation payments, see Figure 15. UKPN's analysis outlines the benefits and drawbacks of a high/low availability price (i.e. retainer) against a low/high utilisation price (i.e. call-off price per unit of dispatched energy).

As noted already the natural desire of a DNO to opt for a "pay-per-use" utilisation payment versus a fixed contract or availability payment is very likely to favour flexibility providers with existing assets, including diesel generators. If DNOs wish to grow the flexibility market and encourage new entrants, a higher degree of revenue certainty and more allowance to stack revenues from other services, will likely be required.

Figure 15: UKPN flexibility service - proposed pricing structure matrix table
See: https://www.ukpowernetworks.co.uk/internet/en/have-your-say/documents/UKPN_Flex_Consultation.pdf

Availability Price (£/kW/h)		Utilisation Price (£/kWh): Low	Utilisation Price (£/kWh): High
	Low	**Low availability and utilisation** • Good for customers, but potentially not for providers. • Low service value could reduce the incentive for service reliability, and increase risks to the network.	**High utilisation and low availability** • The cost to providers of being utilised is covered, but reliance on utilisation payments may reduce revenue certainty. • If frequency of utilisation is variable, the higher uncertainty could lead to higher service costs to customers. • Higher utilisation costs may act as a disincentive for the DSO to use the service.
	High	**High availability and low utilisation** • Higher revenue certainty for providers. Providers may include a conservative estimate of frequency of utilisation, which could increase availability prices. • Customers will have greater certainty on service costs. • Lower utilisation costs may act as an incentive for the DSO to utilise the service more frequently.	**High utilisation and high availability** • Good for providers, but potentially not for customers. • High service value should increase the incentive for service reliability.

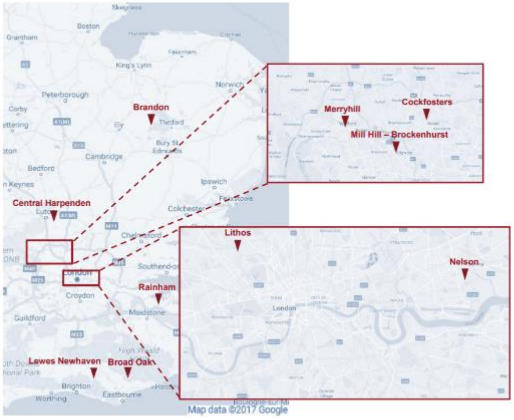
The consultation was followed by an EOI for flexibility services, targeting a range of MW requirements across 10 substation locations (see Figure 16) in UKPN's Southern and Eastern licence areas.

As a result of the EOI and subsequent tender, UKPN has this year agreed bi-directional contracts with a small number of flexibility providers. One of these parties is domestic battery company Powervault, who will be providing flexibility services to UKPN, through a portfolio of 40 x 8kWh batteries across the London Borough of Barnet[25].

[25] See Powervault press release, June 2018: https://www.powervault.co.uk/article/powervault-to-deliver-local-flexibility-in-london-with-ukpn/

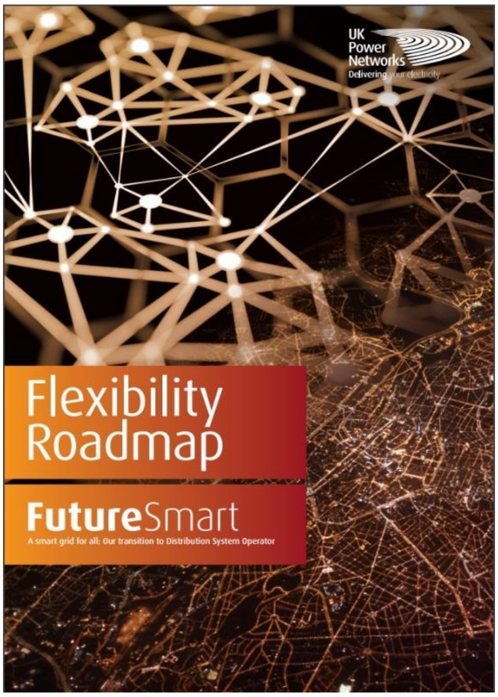
Figure 16: UKPN 2017 EOI - Map of substation areas for flexibility requirements

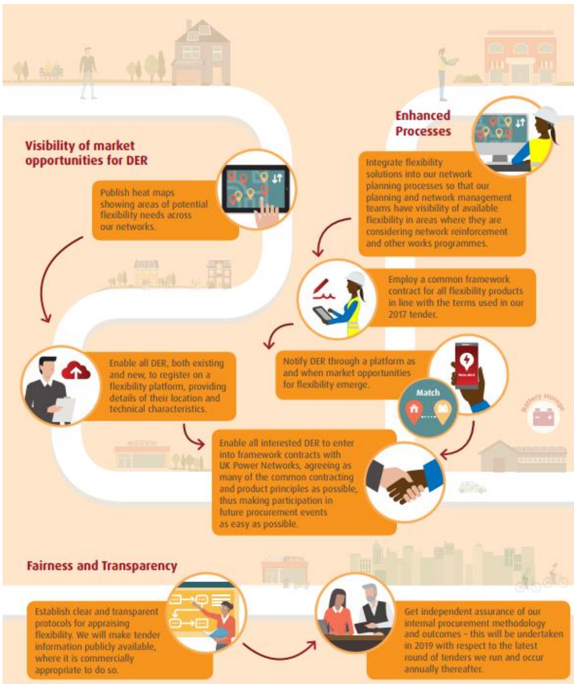
Network location	License area	Voltage level	Requirement 17/18 (MW)	Months	Earliest start date	Latest end date	Times	Days
Broad Oak	SPN	11kV and below	Up to 10	Sep-May	Jan18	May19	7:00 - 8:00am 4.30 - 8.30pm (5hrs)	All
Lewes Newhaven	SPN	33kV and below	Up to 8	Sep-May	Jan18	May19	7:00 - 8:00am 4.30 - 8.30pm (5hrs)	All
Rainham	SPN	11kV and below	Up to 3	Sep-May	Jan18	May19	7:00 - 8:00am 4.30 - 8.30pm (5hrs)	All
Nelson	LPN	11kV and below	1.5	Nov-Mar	Jan18	Mar19	4:00 – 7:00pm (3hrs)	All
Lithos	LPN	11kV and below	2	Jan-Mar	Jan18	Mar19	5:00 - 8.00pm (3hrs)	Weekdays
Merryhill	EPN	11kV and below	2.7	Nov-Feb	Jan18	Feb19	5.30 - 8.30pm (3hrs)	Weekdays
Mill Hill - Brockenhurst	EPN	11kV and below	1.4	Dec-Feb	Jan18	Feb19	5.30-7.30pm (2hrs)	Weekdays
Cockfosters	EPN	11kV and below	1.4	Dec-Feb	Jan18	Feb19	5.30-7.30pm (2hrs)	Weekdays
Central Harpenden	EPN	11kV and below	2.7	Nov-Feb	Jan18	Feb19	5.30-7.30pm (2hrs)	Weekdays
Brandon	EPN	11kV and below	2.7	Nov-Feb	Jan18	Feb19	5.30-7.30pm (2hrs)	Weekdays



3.3.2.1 UKPN FutureSmart: Flexibility Roadmap

Following the 2017 consultation and first round of flexibility tenders, in August 2018 UKPN published a more comprehensive roadmap[26] outlining its future plans and strategy to facilitate the future market for flexibility in its licence areas.





The roadmap document sets out a timetable for future flexibility tenders, as well as providing more detail and clarification of UKPN's flexibility requirements as it plots a transition from a DNO to DSO

[26] UKPN Future Smart Flexibility Roadmap, August 2018 : http://futuresmart.ukpowernetworks.co.uk/wp-content/themes/ukpnfuturesmart/assets/pdf/futuresmart-flexibility-roadmap.pdf

function. The roadmap articulates the increasing role that will be played by flexibility within a changing energy system and identifies four main value drivers for flexibility services within the UKPN network:

- Reinforcement investment deferral
- Planned maintenance
- Customer interruptions
- Avoided cost of temporary generation

The first two of these value drivers are planned and therefore suitable for availability contracts, while the latter two value drivers are related to unplanned faults and interruptions and therefore are more suited to a framework contract and utilisation payment structure.

Interestingly, the roadmap outlines a very transparent and inclusive flexibility market procurement process, including the use of a digital flexibility trading platform (Open Utility's 'Piclo Flex' platform[27]). Use of this platform will enable flexibility market participants to pre-qualify their services against UKPN's flexibility requirements, receive notifications of flexibility opportunities and manage service delivery. UKPN has stated that the fairness and transparency of the market will be underpinned by a set of procurement protocols and assured by a third-party assessor.

There is a lot of information in the roadmap about UKPN's role and ambition to facilitate a new flexibility market and to make the DSO a counterparty that is "easy to do business with", in a transparent and neutral way by providing visibility of market opportunities, enhanced tender and procurement processes and an overarching theme of fairness and transparency. The roadmap outlines a proactive engagement and communications process, designed to encourage participation from a wide range of DER providers.

[27] Piclo Flex Platform https://www.openutility.com/piclo/

Figure 17: Overall flexibility product requirements (Source and credit: UKPN)

Flexibility Products		Reinforcement Deferral	Planned Maintenance	Unplanned Interruptions	
				Pre-Fault Response	Post-Fault Response
Value Drivers		The present value of deferring capital expenditure	Managing unplanned interruption risk during planned maintenance	Customer Interruption (CI) and Minutes Lost (CML) incentives	Avoided cost of temporary generation and potentially CMLs
2023 Flexibility Potential (MW)		206	Available to eligible DER capacity		
High-Level Requirements	**Location Specific**	Yes			
	Response Time	30 mins maximum		<10 mins preferred, 30 mins maximum	
	Response Duration	Full availability window – case dependent. Pro-rated payment if available for part of window		3 hours. Pro-rated payment if available for part of window	
	DER Type	Generation, Storage and Load Reduction			Generation and Storage
Contracting Principles	**Procurement Type**	Competitive tenders or administratively set prices if low liquidity		Framework agreement. Optional updating of pricing through contract	
	Procurement Lead Time	6 months ahead and 18 months ahead	Case specific 1–12 months	DER applies if eligible	
	Payment	Availability and Utilisation		Utilisation only	
	Contract Term	1–4 years	Monthly or seasonal	Framework agreement	

The flexibility procurement timeline outlined in the roadmap envisages annual tenders for 6-month and 18-month ahead contracts, with an ongoing process of short-term contracting for planned maintenance and unplanned interruptions.

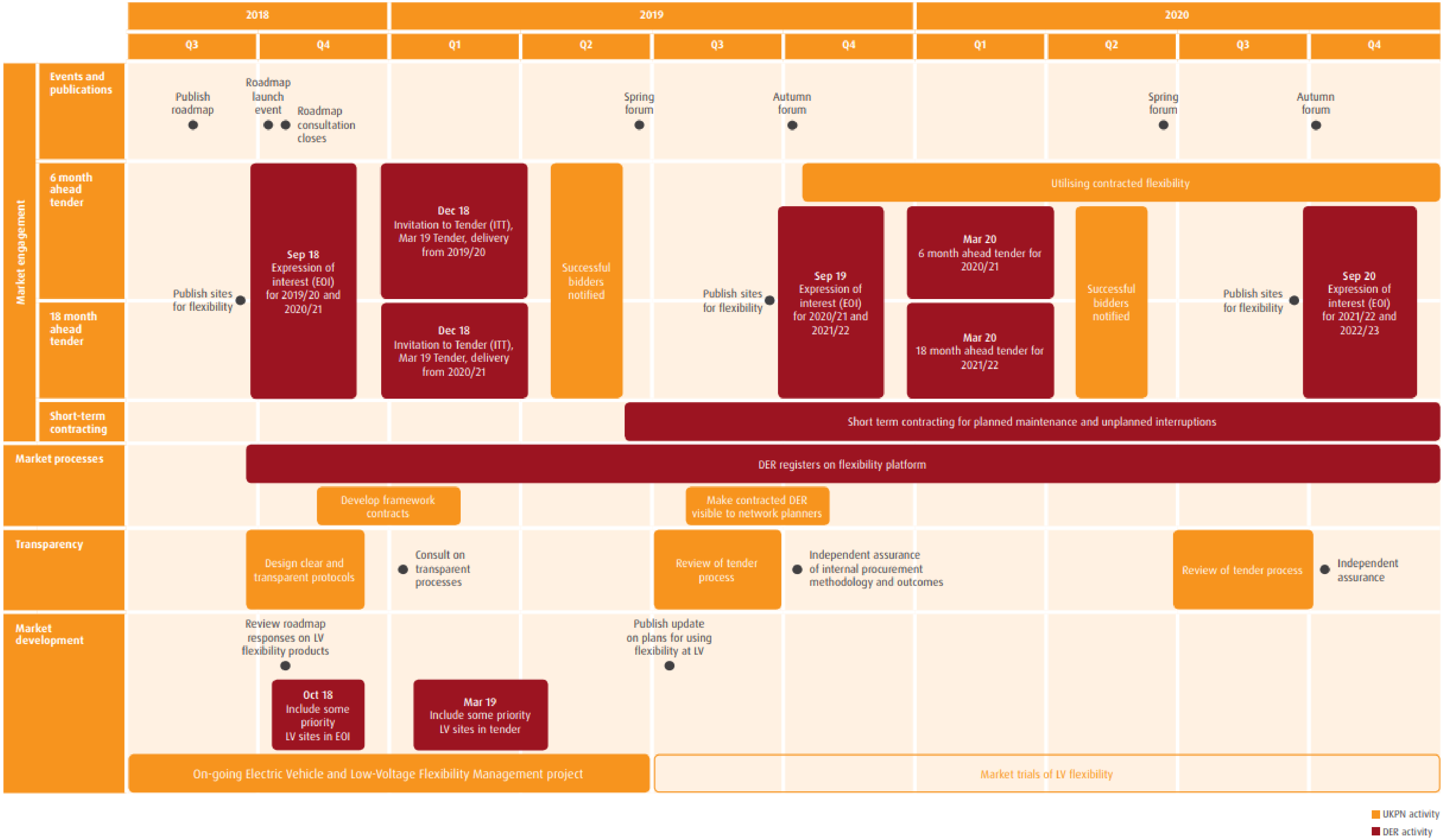
In terms of market size, the roadmap identifies a growing number of substations with flexibility potential, mainly driven by increasing demand from the increased uptake of EVs, reaching a total of 53 substations by 2022. At this point, the market for investment deferral could reach 206 MW.

UKPN suggest that the priority focus for tenders in 2019 will be to manage demand constraints on the high voltage (HV) network and Extra High Voltage (EHV) network. There is evidently a less pressing need for flexibility at the Low Voltage (LV) network discussed in the roadmap, but it is expected that flexibility requirements will increase on the LV network, due to the growth of EVs and the electrification of heat, which could create an even greater market opportunity.

"We expect the trend of decentralised energy to continue at lower voltage levels. As yet, we have not seen the same level of change on our low voltage networks as on our higher voltage networks, but expect this to rapidly change with electric vehicle take up, and an increase in electrification of heating. The future challenges on our low voltage networks could be greater than the ones we are already managing on our HV and EHV networks." **UKPN Flexibility Roadmap, August 2018**

This new market for LV flexibility could be significantly different with much more highly localised, dynamic and unpredictable requirements, which in-turn lends itself to more dynamic and real-time flexibility market solutions.

Figure 18: UKPN flexibility services timeline (source and credit: UKPN)



3.3.3 Electricity North West

In April 2018, ENW also went out to the market to understand the interest to provide flexibility for seven substation locations (see Figure 19), for winters 2018/19 and 2019/20. ENW is following a similar format to other DNOs, targeting DERs connected at specific locations, with financial incentives to adjust how much they consume or generate, in response to times of high demand or "*when the network is operating abnormally*".

Figure 19: ENW flexible services requirements (Source: ENW, Apr 2018)

Network location	Voltage	2018/19 Flex Requirement (MW)	Availability window		
			Months	Times	Days
Alston	LV or HV	0.5	Nov - Mar	06:30 to 21:30	All week
Coniston	LV or HV	1.0	Nov - Mar	All day	All week
Easton	LV or HV	2.0	Nov - Mar	All day	All week
Nelson	HV or 33kV	20.0	Oct - Mar	06:30 to 21:30	All week
Blackfriars	LV or HV	0.5	Jan - Feb	16:30 to 21:30	Weekdays
Cheetham Hill	LV or HV	2.5	Nov - Mar	11:30 to 21:30	All week
Stuart Street	HV or 33kV	9.5	Nov - Feb	06:30 to 21:30	Weekdays

There are a number of conditions that ENW require of potential providers, as follows:

- DERs have to be connected to the network assets being supported, checked via the submitted meter point administration numbers (MPANs)
- There are no restrictions on size of sub-sites of aggregated portfolios, but the total portfolio of flexible capacity needs to be at least 200 kW
- Minimum size for directly contracted resources should also be at least 100 kW
- Provider should be able to deliver and manage, upon ENW's request, a net reduction in the load or an increase in the export, as seen by the distribution network
- Flexible service provider should have the ability to act (provide a response) reliably and consistently, in both magnitude and duration, throughout the contracted windows
- ENW are open to all technology types that can meet requirements. Flexible service providers may represent any existing or new industry sectors and any type of response mechanisms, such as demand reduction, demand offset, generation export or electrical storage discharge
- Generators and storage (greater than 16A per phase) looking to export to the network, will need to have a long-term parallel connection and be compliant with the requirements of UK Engineering Recommendation G59/3-3[28]
- Flexible providers should be able to deliver the service during winter 2018/19 (starting November 2018) and/or next winter (2019/20)

This echoes similar principles to other DNOs, but is less prescriptive in certain areas, such as verification metering/monitoring requirements. In regards to pricing, ENW have stated they are open to discussion.

[28] See ENA EREC G59/3-3: https://www.nationalgrid.com/sites/default/files/documents/GC0079%20Annex%203%20Option%201%20G59%20proposals%20170731.pdf

The results of this EOI are currently being analysed and ENW be releasing the outcomes, next steps and what they are taking forward through to full tender.

3.4 Additional DNO engagement

The project undertook to engage contacts at all of the major UK DNOs, liaising with key members of innovation, DSO transition, smart grid and future networks teams, see Table 5. Unfortunately, the project was unable to engage SPEN on specific areas.

Table 5: DNO engagements - contacts

DNO	Contact	Engagement
electricity north west Bringing energy to your door	**Simon Brooke** Capacity Strategy Manager **Helen Seagrave** Community Energy Manager	3 May Meeting, Manchester
WESTERN POWER DISTRIBUTION Serving the Midlands, South West and Wales	**Matt Watson** Innovation and Low Carbon Networks Engineer **Nigel Turvey** Network Strategy and Innovation Manager	28 June Meeting, Bristol
Scottish & Southern Electricity Networks	**Steve Atkins** DSO Transition Manager	29 June Phone interview
UK Power Networks	**Sotiris Geogiopoulos** Head of Smart Grid Development	4 July Phone interview
NORTHERN POWERGRID	**Jim Cardwell** Head of Regulation and Strategy	4 July Phone interview

The interviews discussed a number of key topics around the approach and basis of DNOs seeking to procure flexibility. Whilst there were bespoke questions aimed at individual DNO projects and activities, the interviews focussed on the following topics:

- **Approach and need for procuring flexibility**
- **The indicative size of the market**
- **Entry requirements**
- **Verification methods**
- **Payment structure and pricing**

In addition, the interviews sought to understand how each of the DNOs intended to meet their regulatory requirements of not only enabling and facilitating local flexibility markets, but also to level the playing field for community and domestic entrants to local flexibility markets.

The following sections detail a summary of the responses on these topics.

3.4.1 Flexibility service needs

All of the DNOs are working towards their regulatory requirements under the DSO transition and are almost all involved in Network Innovation Competition (NIC) funded projects[29]. The current operational need for flexibility varies across the DNOs, with UKPN, WPD, SSEN and ENW moving beyond innovation trials to seeking interest or issuing live tenders for flexibility services.

The actual requirements for flexibility was also stated by the DNO representatives as seeking to manage or mitigate peak demand 'pinch points' on the network, calling on demand turn-down or generation turn-up responses. WPD discussed the value of demand turn-up, referencing a trial with National Grid[30], but stated that there was no immediate intention to procure flexibility to help to manage generation

[29] See examples of NIC funded projects: WPD EFFS | SSEN & ENW Transition | SPEN FUSION
[30] See National Grid demand turn-up overview, January 2017: https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/demand-turn

constrained areas. Measures for this are in-place through existing connection charging on distributed generation, alternative connection offers and ANM.
It was noted that if Ofgem's proposed changes[31] to make connection charging 'shallower' come to fruition, DNOs may no longer be able to pass the full upgrade costs onto generators and the potential for DNOs to procure flexibility to managing generation may change.

This approach to change to 'shallow' access charging would mean that new distributed generation would only need to pay "*for their own their own sole-use assets through the connection charge, and not also any wider reinforcement and shared operational costs that are triggered.*" This means that the DNO may turn to a flexibility procurement approach to help manage generation capacity constraints in certain areas, as they are currently doing for demand. In essence, in this scenario demand turn-up and storage charge-up (or even generation turn-down) may become types of flexibility response.

3.4.2 Geographical location

For the DNOs that have signposted their near term flexibility needs, a key consideration is that these demand constraint led services are very localised, with needs being specified against individual substation areas or geographically ringfenced 'flexibility zones'/CMZs.

This approach really encapsulates a key difference between national balancing services and local flexibility markets, suggesting that only DERs connecting to the distribution network within these areas, will be eligible to express interest and go on to contract with the DNO. Simply put, if a flexible asset is not located in one of the zones that their regional DNO has specified, they will not be able to participate in local flexibility markets, under the current arrangements.

3.4.3 Capacity thresholds

The ability for smaller scale participants to enter and provide paid-for services to the network is considered to be one of the main potential benefits of local flexibility markets. The entry threshold for national balancing services is a technical barrier to a direct contract between a smaller flexible asset and National Grid. The need for generators or demand sites that have a flexible capacity below 1 MW, for example, would require an arrangement with an Aggregator, to enter as part of a portfolio of smaller sites. The role of the Aggregator is discussed in section ▯ of this report.

The entry thresholds proposed through the live EOIs are lower than this, with some DNOs specifying specific entry capacity of 100 kW and ENW specifying 200 kW if part of an aggregated portfolio.

Other DNOs have been less specific on this issue, stating that whilst 100 kW seemed a sensible threshold, there is the potential for this to drop to say 50 kW in the future. There were other more agnostic views, with some DNOs being open to providers at any scale. Finding out the level of interest through a more open procurement process, was also seen by some DNOs as more valuable than dictating a specific minimum entry capacity.

The issue of 'single point of failure' was also raised, when discussing small participants being aggregated together through a single, central platform. If this platform was proven to be reliable in enabling an aggregated portfolio to respond, more than one DNO considered this would be acceptable.

[31] See Ofgem consultation document "Getting more out of our electricity networks by reforming access and forward-looking charging arrangements":
https://www.ofgem.gov.uk/system/files/docs/2018/07/network_access_consultation_july_2018_-_final.pdf

As part of their EOIs, WPD have also specified that in a situation where they have over-procured capacity (week-ahead), they would draw on a series of principles[32] that prioritises several smaller sites, over single or fewer larger sites.

3.4.4 Entry requirements

Aside from capacity and geographical location considerations, a number of specific technical requirements are stipulated by the live EOIs from the DNOs. These stipulations range from:

- The need for half hourly settlement metering
- Additional minute by minute monitoring (to verify flexibility has been dispatched)
- Response requirements ranging from 15min to 30min notices periods, or no specific time
- Sustained duration ranging from 2-5 hours
- Assurances that existing connection agreements are not breached

The discussions with the DNO representatives suggested that some requirements were left intentionally open. It was also suggested that some specifications may be assessed and agreed through the EOI process and more specific or detailed requirements would be put in place at tender or contract stage.

3.4.5 Contract duration

There was some alignment in this area, with multiple DNOs suggesting an indicative contract length of between 2-4 years. Others stated that this was an area that remains undecided and may be related to the purpose that the flexibility is serving. This suggests that a local flexibility contract duration could range from a 6-month rolling arrangement to a firm 4-year contract and may depend on the licence area, the type of flexibility service and the specific network location. Longer contracts are unlikely.

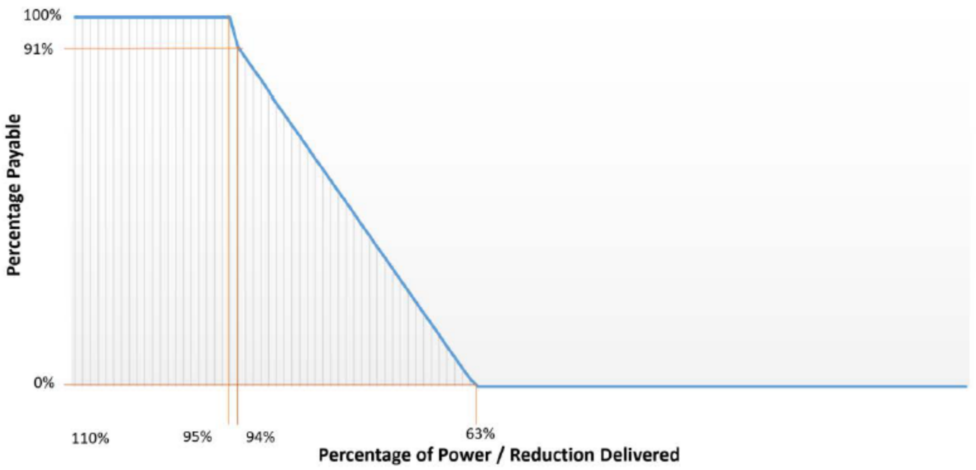
3.4.6 Non-delivery

There was a lot of alignment around this area, with the DNOs largely aligned that they would not enforce a penalty for underperformance or non-response. Instead the intention was that the incentive payment would be withdrawn or reduced, based on the amount of frequency of underperformance.

WPD have probably shared the most detail around this area, through their ‘sliding scale’ methodology for utilisation payments, see Figure 20. This relates to an approach where during a call, a DER asset either takes too long to ramp up to full capacity, drops out half way through or doesn’t respond at all. WPD have proposed giving an initial 5% ‘grace factor’ and then to reduce utilisation payments by 3% for every 1% underdelivered against declared flexible capacity, on a minute by minute basis. Effectively meaning that between 95% and 100% of declared capacity, a DER would receive full payment, between 95% and 63% payments would decrease at a ratio of 3:1 and below 63% zero payments would be made.

[32] See Flexible Power Winter 2018 and Summer 2019 EOI, page 14, “Assessments”: https://www.flexiblepower.co.uk/FlexiblePower/media/Documents/Winter-2018-Summer-2019-EOI-Document.pdf

Figure 20: WPD sliding scale of utilisation payments under Secure and Dynamic services
(Source and credit: WPD Flexible Power Invitation for EOIs: Services for Winter 2018 and Summer 2019)



Whilst not necessarily a standard approach, the feedback received from WPD and other DNOs was that the services need to be reliable and to the capacity that was agreed, when the DNOs call them to action. There were discussions about recovering payments made if responses were not valid. A '3 strikes and out' view to cancelling contracts with parties that continually underperform, was also discussed.

3.4.7 Procurement approach

There are again some areas of similarity in the approach to engaging and procuring flexibility across the DNOs. Some examples include DNOs consulting on the method of engagement and 'advertising' flexibility needs through EOIs, online questionnaires or design consultations.

The actual approach to procuring, contracting and calling on DERs is, however, insufficiently established to determine trends or consistent approaches. At present, a number of the DNOs are working through EOIs, with a view to moving to full tenders. The examples of some of the timelines are shown in Figure 21 and Figure 22.

Figure 21: WPD timeline for procuring flexibility services in 2018

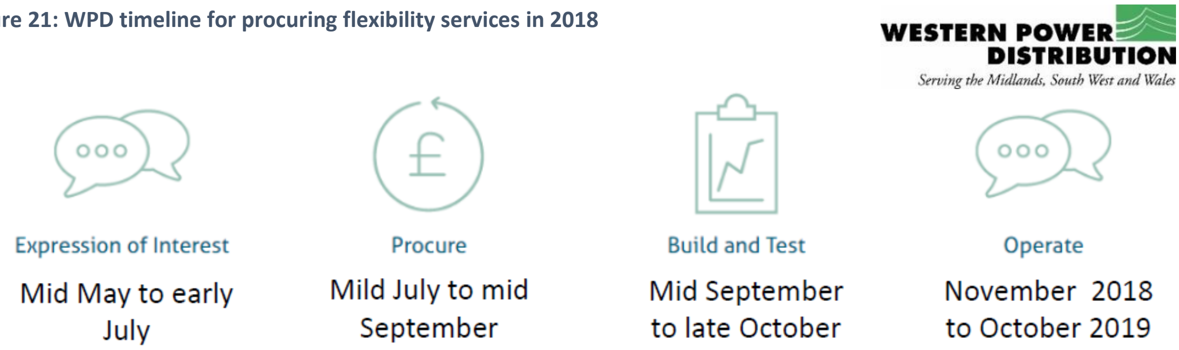
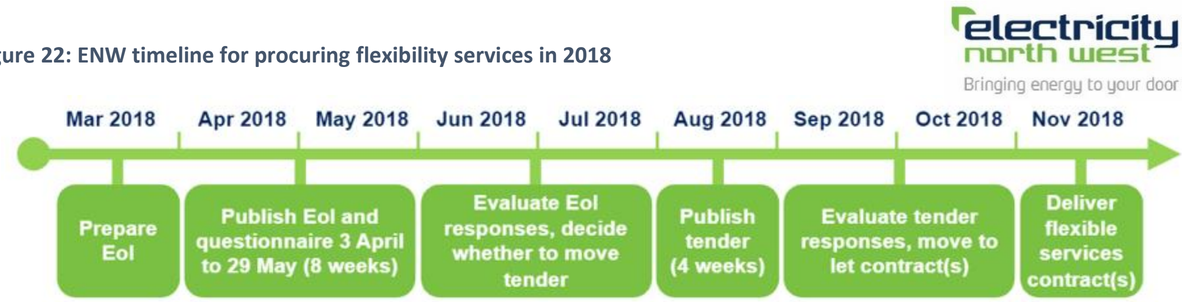


Figure 22: ENW timeline for procuring flexibility services in 2018



Whilst EOIs are an open method by which DNOs are seeking overall interest in flexibility services, some of the DNOs proposed a potential need to use additional, parallel or follow-on approaches to advertise flexibility needs. WPD was clear that responding to the EOI was not the only method by which DERs could participate or bid their flexibility to the DNO. It is assumed that other DNOs would follow a similar approach, so as to ensure that they gain access to sufficient cost-effective flexibility to meet their needs.

One method by which flexibility is to be advertised, bid for and potentially contracted is to advertise through central flexibility trading platforms. One such example is Piclo Flex[33], developed by Open Utility, with three DNOs now announcing intentions to publicise their flexibility on this platform.

Another example is Centrica[34], who are trialling the technical interactions of a local energy market platform in Cornwall. This project is aiming to deploy control devices and flexibility assets across various sites in Cornwall, communicating back to a central platform. This platform is then to be loaded with test constraints (both demand and generation) from WPD, to simulate how a platform of local flexibility services might respond. This project is currently not assessing the commerciality of flexibility responses.

[33] See Open Utility Piclo Flex platform: https://www.openutility.com/piclo/

[34] See Centrica Cornwall LEM project: https://www.centrica.com/innovation/cornwall-local-energy-market

3.4.8 Levelling the playing field for smaller entrants to flexibility markets

From speaking with all of the DNO representatives there was a clear awareness that they would not wish to exclude or block energy flexibility at any scale. However, at this stage, the perception of the value and reliability of domestic flexibility (in its current form) is varied across the DNOs.

When discussing what actions are being undertaken to level the playing field for smaller participants, effectively seeing DNOs following through on the requirement of being non-discriminatory, there was some diversity in the approach. Overall, the DNOs all cited engagement work with local organisations as a key method to gauging feedback and raising awareness of the local flexibility needs and actions.

Engagement ranged from independent organisations such as Regen, Community Energy England, Community Energy Scotland and Low Carbon Hub, through to local bodies such as Local Enterprise Partnerships, Local Authorities and Scottish Government.

The approach to consulting on market design and signposting, was also referenced as the DNO turning to their connected customers to provide feedback on the method by which they are seeking to advertise flexibility needs and services.

Regen worked closely with WPD to deliver a series of events[35], seeking to provide information about the development of flexibility markets. Speakers from WPD, Regen, Carbon Co-op, Piclo (previously Open Utility), developers and community energy organisations provided a summary of recent developments and the potential opportunities for communities.

Figure 23: WPD 'flexibility markets for beginners' event Birmingham, July 2018 (source and credit: WPD)

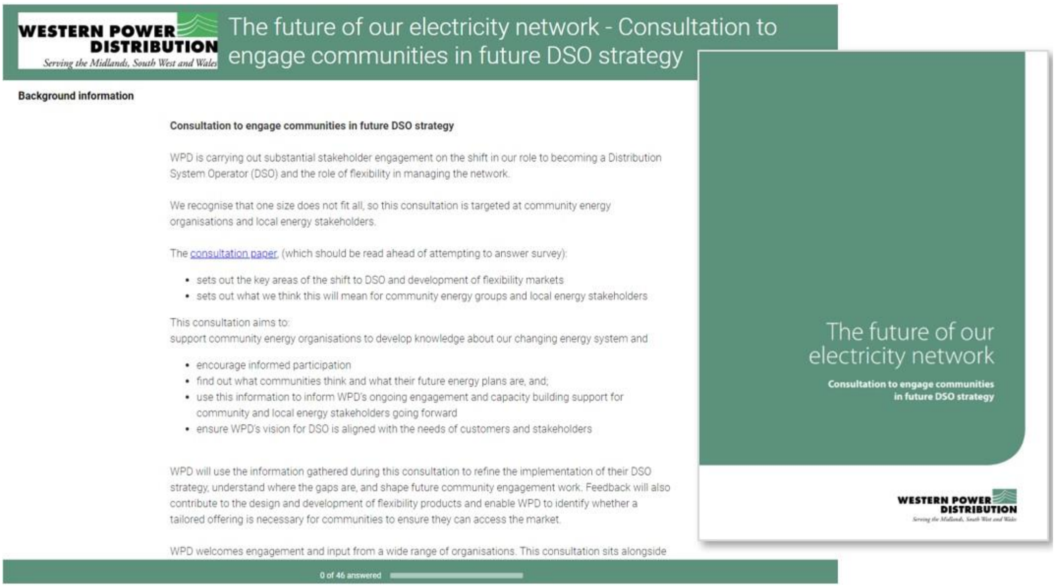
In addition to this, WPD have recently launched a consultation seeking communities' views of flexibility and the wider transition from DNO to DSO. The consultation comprises an online questionnaire[36] and an accompanying consultation paper[37] that aims to:

- *Support community energy organisations to develop knowledge about our changing energy system and encourage informed participation*
- *Find out what communities think and what their future energy plans are, and;*

[35] See summary of 'Flexibility Markets for Beginners' WPD events, July 2018: https://www.westernpower.co.uk/About-us/News/Flexibility-Markets-for-Beginners.aspx
[36] See WPD survey monkey questionnaire: https://www.surveymonkey.co.uk/r/3DQV9HS
[37] See WPD consultation paper, 'The future of our electricity network – Consultation to engage communities in future DSO strategy', August 2018: https://www.westernpower.co.uk/docs/connections/Generation/Community-Energy-Schemes/WPD-DNOtoDSO-Community-Consultation-Paper.aspx

- *Use this information to inform WPD's ongoing engagement and capacity building support for community and local energy stakeholders going forward*
- *Ensure WPD's vision for DSO is aligned with the needs of customers and stakeholders.*

Figure 24: WPD consultation paper and online questionnaire (source and credit: WPD)



The consultation refers to various topics under WPD's DSO transition, seeking views, community interest to participate, the nature of information that is made available and general feedback under the areas of:

- WPD's DSO strategy and its core principles
- The role and value of flexibility in an electricity system
- Alternative connections
- WPD signposting of flexibility need
- WPD's online mapping information (network capacity network flexibility maps)
- Types of flexibility responses
- WPD as a neutral market facilitator
- Ability to access multiple services/revenue streams
- Tender process
- Where, when, how much and how often flexibility is required
- Metering, payment structure and pricing

The consultation paper is available to download from WPD's website:

https://www.westernpower.co.uk/Connections/Generation/Community-Energy/The-future-of-our-electricity-network.aspx

Some requirements of these services are more readily achievable by C&I parties than potentially by aggregated communities or domestic loads. However, with some DNOs potentially aiming to encourage and even prioritise smaller scale flexibility, some of the more stringent entry requirements may need to be targeted or revised.

SSEN's discussed an intention to create 'Social CMZs', seeing SSEN directly supporting communities through the complexities of a flexibility tender process. Other technical barriers such as metering and verification, could also potentially be mitigated by DNOs providing a monitoring device as part of the contractual arrangement with community/domestic participant.

DNOs are required to remain impartial and agnostic to their connected customers/service providers, so how these support measures are to be deployed for certain parties and not to others, may need to be carefully stipulated and justified. Similarly, DNOs cannot discriminate (positively or negatively) one technology over another, one class of DER over another or, in principle, one group of actors over another. Thus, the complexities of entering or contracting with the DNO should not act as a barrier for one group of potential flexibility providers.

3.5 DSO flexibility markets - conclusions and considerations

From reviewing DNO to DSO strategies and market activities, and direct engagement with DNO network innovation teams, some key conclusions can be drawn in relation to the feasibility of an ECAS engaging with a DSO led flexibility market:

i) DNOs are at different stages in terms of procuring flexibility locally.

All of the DNOs are moving away from funded trials and innovation projects to their business as usual processes. Some (such as UKPN, WPD and ENW) are further along the process than others. This is limited by a number of factors:

Location: By its nature, DNO led flexibility is focussed around pre-determined areas within regional networks. Certain communities and participants will therefore be limited by how far along the local flexibility markets are, in their specific licence area. This is in some ways linked to the needs of the network, with disruptive demand causing constraints on e.g. more urbanised areas of the network.

Process: Similarly, the need for flexibility has driven some DNOs to further develop their capabilities to call for and contract with DERs to support operational challenges. This has led to some divergence in the approach that potential providers of flexibility have been engaged. Some networks have consulted directly on the method by which flexibility services are advertised, others have publicised open calls for EOIs. Other networks have yet to publicise this information. This effectively has created a small number of 'hot spots' for flexibility needs, creating a geographical limit on those providers that can – and cannot – enter markets directly.

It should be considered that publicising flexibility needs and calling on interested parties to bid their services in a market is not the only method by which domestic flexibility is rewarded. Other approaches, such as NPG's 'GenGame'[38] effectively enables homeowners, to play a role in supporting the DNO with their peak demand management challenges.

Whilst this approach is a completely different offering, this gamification method sees households flexing their demand in response to a signal, which is verified through a home energy monitor device (supplied by NPG) and then paid a financial reward for doing so.

ii) Local flexibility is currently about managing demand peaks

The current focus of procuring flexibility for local networks, is centred around mitigating local network demand peaks and managing unplanned events, maintenance or loss of generation. This effectively denotes three types of flexibility response actions that are currently required:

- **Generation 'turn up':** Activating or increasing generation
- **Storage 'discharge'**: Switching your energy storage asset to discharge/export operation
- **Demand 'turn down'**: Switching off or ramping down energy consuming equipment

Flexibility services required to perform the opposite action, i.e. excess distributed generation management, is not currently being targeted by the DNOs. This is largely due to the regulatory

[38] See NPG GenGame website: http://www.npg-ace.com/get-involved/play-gengame/

framework that requires electricity DNOs to invest and increase network capacity to meet demand growth retrospectively.

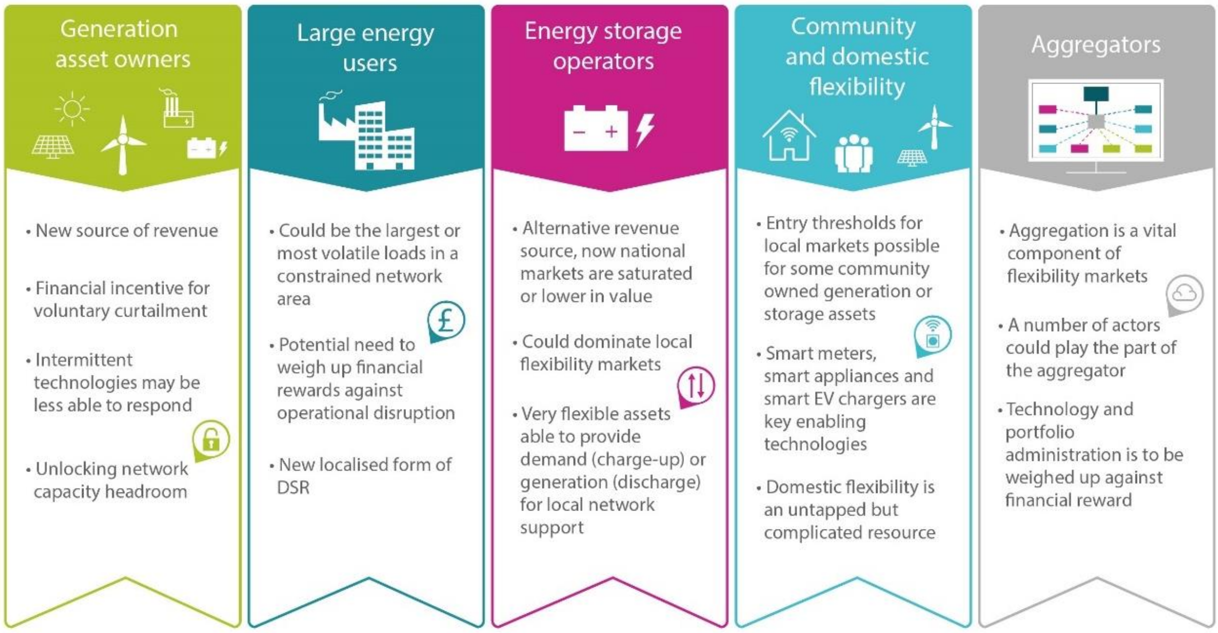
In terms of generation capacity growth, the cost to reinforce networks is either directly chargeable to the developer of that generation or mitigated through measures that DNOs can employ. These measures include offering Alternative Connections[39] such as timed connections, export limiting, temperature monitored connections etc. or more dynamic monitoring such as ANM[40].

iii) The local markets are more readily accessible to commercial and industrial providers of flexibility

From the initial calls for flexibility services, the requirements of providing flexibility services in response to an event or signal, is arguably more readily suited to larger industrial energy users or generators.

The providers of flexibility services could be categorised into five 'classes' of DERs, see Figure 25. For each of these, the development of a local flexibility market is an opportunity, either as a new source of financial income, or the potential to engage in network support to relieve demand constrained areas. However, despite DNOs being technology/approach agnostic, some parties will be able to enter and extract value from local flexibility markets more directly, more easily or more lucratively than others.

Figure 25: Benefits to classes of flexibility service providers



Under the current proposed entry and technical requirements, there are certain technology classes that will potentially be more readily able to bid into EOIs and move forward to contracting. Dispatchable generation, intermittent generation with storage, standalone storage, large energy user reduction and aggregated reliable domestic loads (such as home batteries) are the strongest contenders.

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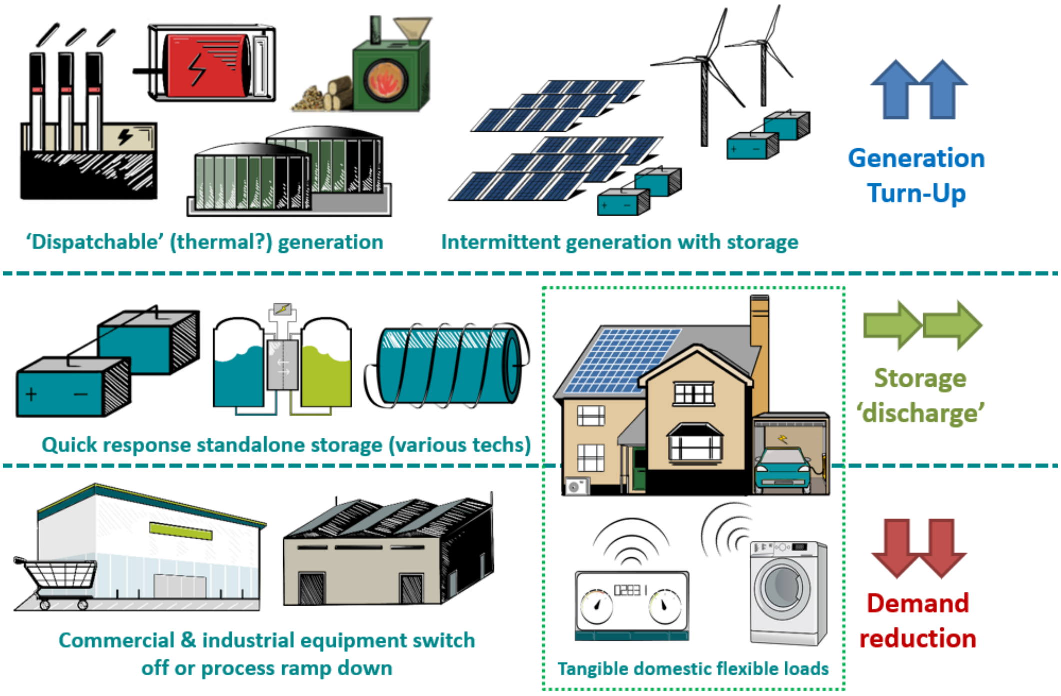
[39] See examples of Alternative Connections from WPD | SSEN | SPEN |

[40] See summary of Active Network Management here: https://www.westernpower.co.uk/Connections/Generation/Alternative-Connections/ANM-Further-Info.aspx

Figure 26: Technology classes potentially able to readily access local flexibility markets

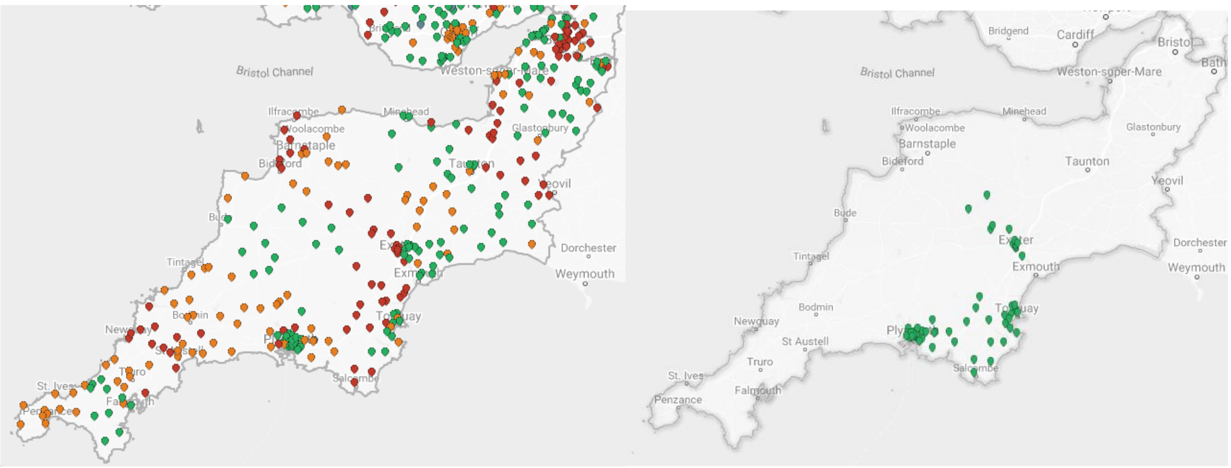


iv) Location is key

Local flexibility markets are, by definition, localised to specific DNO areas and CMZs. This is perhaps the most distinct difference to the national balancing services, in that the ability to access markets is restricted to those assets that are connected to specific substations with flexibility needs.

For example, see Figure 27 that shows the primary substations in the SW area that require flexibility services, compared to all primary substations in the same area.

Figure 27: WPD Network Capacity Map and Network Flexibility Map showing primary substations requiring flexibility
Source and credit: WPD



This means that there will be assets in areas outside advertised CMZs that are automatically discounted from being able to enter. This also might potentially create a scenario where flexibility assets target specific zones or substations to gain access to these markets. With EOIs being at relatively early stage, this is unlikely to happen in the near term.

v) Income will be modest

Flexibility payments are being seen, perhaps prematurely/inadvertently, as a new or alternative source of revenue. Whether to boost income for investing in generation or storage, or as a new method for high energy demand sites to be financially rewarded for dynamically managing their usage, local flexibility is inadvertently being considered as a new source of income for developers.

This is however against a backdrop of generators securing 20-year Feed In Tariff or Renewables Obligation (RO) contracts. The local flexibility markets are not going to be an equivalent to these subsidy programmes. Contract length will be shorter and income will be moderate at best.

Calculating an annual estimated income figure for a given flexible capacity is very difficult. This is due to locational differences in daily/monthly requirements, flexibility service types, prices and a general uncertainty as to the actual frequency and number of calls that will happen per month.

3.6 What does the development of a DSO flexibility market mean for an ECAS model?

In regard to a business model for a service that subscribes/aggregates community or domestic level participants in order to access flexibility services, some key conclusions can be drawn:

- DSO markets are at very early stages across the UK and the ability to assess whether these markets are a definitive source of revenue for the ECAS business model is currently difficult.
- The core specifications of DSO flexibility services, such as entry requirements, location, response times and pricing, may evolve as these markets mature and lessons are learned. The value of smaller assets with a shorter duration of response, may therefore have a value further into the future, as DSOs seek levels of flexibility across their networks.
- The amount of income on offer per kW/MW is likely to be modest; the model may need to pursue additional markets and sources of income to supplement the DSO income. It is thus unlikely that payments to end users would be sufficiently attractive or economically viable.
- The amount of income is also likely to vary significantly, largely according to location. The DSO element of any business model for ECAS, could therefore only be viable in specific areas.
- Fundamentally, increased second generation smart metering in the home will be essential. Additional verification monitoring supplied by the DSO as part of the contract may also be a key enabling factor to make the business case for domestic flexibility stack up.
- To enable domestic flexibility to meet baseline, entry and operational requirements of the DSO, manual operation of appliances or electronic devices is unlikely to have sufficient impact.
- further uptake of technologies, such as home batteries, heat pumps, electric water tank heaters and EVs will be needed.

The key parties related to an ECAS model are outlined in Table 6.

Table 6: Parties involved in DSO flexibility markets through an ECAS model

Party	Potential Roles
ECAS host organisation	Legal entity Host of subscription/member service Host and coordinator of revenue to/from members
Community or domestic participants	End consumers, host or owners or DER assets Flexibility responders Recipients of fixed or variable payments
Third party commercial Aggregator	Aggregator with or without supply licence Incorporation of ECAS member portfolio into existing Aggregator portfolio Potential to contract with DSO
Flexibility market platform facilitator	Entity that sits behind visibility/procurement platforms (such as Piclo Flex) Advertising DSO flexibility requirements and coordinating bids and auctions
The DSO	Procurer of flexibility services Contractual counterparty for either ECAS directly or Aggregator

The commercial arrangements could involve a number of different interactions between these parties. Scenarios might include:

(A) Community/Domestic DERs ←→ ECAS ←→ DSO

(B) Community/Domestic DERs ←→ ECAS ←→ Commercial Aggregator ←→ DSO

(C) Community/Domestic DERs ←→ ECAS ←→ Market platform ←→ DSO

(D) Community/Domestic DERs ←→ ECAS ←→ Commercial Aggregator ←→ Market platform ←→ DSO

The strength/weakness of these approaches will depend on a number of factors. A primary consideration is what the core functions of the ECAS will be, whether it is to undertake some or all of the following functions:

[1] Subscription: Engaging, recruiting and signing up individual households to the ECAS service
[2] Aggregation: Combining loads and responses to be a portfolio of sufficient size, that can be bid into, entered and called upon in local flexibility services
[3] Register and bid: Submit necessary portfolio data/locational information in response to EOIs or tender processes
[4] Dispatch: Either notifying or remotely activating domestic flexible loads in response to DSO calls or notifications
[5] Verification: Collate and submit flexibility response evidence/data for the duration of flexibility calls (HH smart meters and minute-by-minute devices)
[6] Settlement: Distributing revenue returned to the ECAS portfolio (if applicable)

Under these actions, the involvement of a third party Aggregator and market platform host (as possible intermediaries) could be determined by:

- The capability and remit of the ECAS organisation,
- The level of recruitment that ECAS has achieved in a given DSO flexibility CMZ,
- The appetite for commercial Aggregators to enter into a sub-agreement with a community Aggregator and how revenue is therefore to be distributed (could be Aggregator-specific),
- Whether the DSO seeks to advertise flexibility needs outside of visibility platforms, or whether these may become the sole routes to market,
- The support DSOs are willing to provide ECAS as a representative of community/domestic participants, in terms of both guidance through the procurement process and physical support by providing necessary verification monitoring as part of the contract.

Evidently the fewer parties involved will mean there is more revenue available to each party. The ultimate preference would therefore be Scenario (A), where ECAS contracts directly with domestic DERs and a portfolio of aggregated loads is offered and contracted directly with the DSO. The involvement of a third party commercial Aggregator to incorporate the ECAS loads, would dilute secured revenues. The need to route revenue through a flexibility platform may also reduce the benefit to end parties. In terms of the commercial arrangement between ECAS and domestic participants, a number of options could be considered. These are outlined, alongside the pros and cons in Table 7.

Table 7: High level ECAS commercial arrangement considerations

Arrangement	Pros	Cons
Fixed subscription fee *Domestic users pay an annual or monthly fee to ECAS for access to their DER assets, and user retains 100% of DSO income*	Guaranteed income to ECAS, removes risk to ECAS model	Risk of low or no income to user from either limited DSO calls or regular failure to respond.
Agreed percentage of income *ECAS and domestic users share DSO income*	Fair and equitable approach Proportion could be openly calculated to cover costs/ margin for ECAS in their role	Uncertain income to both parties

ECAS fixed annual payment *ECAS pays an annual or monthly payment to user, ECAS retains 100% of DSO income*	Guaranteed income to user, removes risk to them and could increases the potential to recruit participants	Risk of low or no income to ECAS from either limited DSO calls or regular failure to respond.

3.7 Existing commercial Aggregator activity

3.7.1 Background

The DSR market is rapidly diversifying, from a small number of industrial and commercial consumers, to more recently an increasing number of actors entering the market through aggregation models and flexible technologies. This has enabled a wider participation in flexibility and balancing markets with financial incentives. Aggregators are at the centre of these markets, as they help to bridge the gap between small-to-medium sized consumers and the procurers of flexibility[41]. National Grid references a wider term of Demand Side Flexibility (DSF), to incorporate demand, generation and storage[42] actions.

An Aggregator in this context is a third-party intermediary, which coordinates DSF responses from individual parties, aggregated to meet the technical requirements of the ESO or the DNO, as a route to market[43]. Some Aggregators coordinate this response by sending signals to their customers to modify their generation or demand through a manual 'call and respond' notification arrangement via text message or email, whereas others take full remote control of a customer's on-site asset, to automatically respond to SO or DNO requirements or a market price signal. There are also examples of instances where Aggregators operate a middle ground between these methods, by integrating their DSR response within the consumer's existing site's control systems.

Over the past few years with the development of the national balancing services market[44] (under their *Power Responsive* programme), the Aggregator business model has centred around these services, providing a route to market for smaller participants that are unable to contract with National Grid directly. This helps the SO to balance the network through services such as DSF, Frequency Response (such as FFR or EFR) and Short Term Operating Reserve (STOR). The development of this market has provided a business model for commercial Aggregators, who are able to enable flexibility from participants who are individually too small to enter these programmes to participate. For example, many balancing services have an entry threshold of 1 MW[45], as is the case for Enhanced Frequency Response (EFR), which can be aggregated through a portfolio of smaller sites. Over 90 per cent of Aggregators listed by the National Grid as providing aggregation offer services to both DSR consumers and small generators as a way of diversifying their business models[46].

Following on from the development of this national market, Ofgem has mandated DNOs need to develop markets for flexibility services at the regional level as part of the DNO to DSO transition, often referred to as 'facilitating local flexibility markets'[47].

[41] ADE Demand Side Response Code of Conduct Consultation https://www.theade.co.uk/news/ade-news/ade-demand-side-response-code-of-conduct-consultation
[42] http://powerresponsive.com/wp-content/uploads/2018/02/Power-Responsive-Annual-Report-2017.pdf
[43] https://www.ofgem.gov.uk/system/files/docs/2016/07/Aggregators_barriers_and_external_impacts_a_report_by_pa_consulting_0.pdf
[44] https://www.nationalgrid.com/uk/electricity/balancing-services
[45] https://www.nationalgrid.com/uk/electricity/balancing-services/reserve-services/demand-turn?technical-requirements
[46] https://www.ofgem.gov.uk/system/files/docs/2016/07/Aggregators_barriers_and_external_impacts_a_report_by_pa_consulting_0.pdf
[47] https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf

3.7.2 Current Aggregator market activity

Details of some of the organisations who are active in commercial aggregation are listed on National Grid's DSR website. An overview of these organisations and a high-level assessment of their involvement in local flexibility markets, is outlined in Table 8.

Table 8: Commercial Aggregator local flexibility summary

Aggregator	Local Flexibility Involvement
Actility See: ThingPark Energy website	Internet of Things (IoT) platform, ThingPark Energy delivers DSR. Collects data from 1000's of assets and aggregates available flexibility using Aggregation Server (DAAS), mainly from industrial sites
AMERESCO Green • Clean • Sustainable See: Ameresco DSR website	DSR primarily in the US
EDF See: EDF DSR website	DSR flexibility for businesses at least 250 kW of flex
GridBeyond formerly Endeco Technologies See: Endeco website	DSR flexibility for industrial/commercial users, National Grid (NG) scheme
Energy Pool See: Enery Pool website	DSR flexibility, mainly for businesses, NG schemes
ENERNOC See: EnerNOC DSR website	DSR flexibility for businesses, NG scheme
e-on See: E.ON VPP/DSR website	DSR flexibility for businesses to DNO
Flexitricity See: Flexitricity DSR website	DSR aggregation to DNOs
engie See: Engie Energy website	DSR (STOR) aggregation from 250 kW loads for NG

KiWiPOWER demand management See: Kiwi Power website	DSR/DSF for businesses, looking to enter potential local flexibility markets
limejump See: Limejump website	Aggregation for NG, mainly for businesses, 'Virtual Power Plant' (VPP) platform
npower See: Npower DSR website	DSR/DSF for businesses, NG scheme
open energi See: Open Energi website	DSR/DSF, aggregated from local generation through 'Dynamic Demand 2.0' platform
origamienergy See: Origami Energy website	Ancillary/balancing services flexibility, NG scheme
PEARLSTONE ENERGY See: Pearlstone Energy website	Aggregates from C&I clients to create VPP of 'Negawatts', Automated Demand Response (ADR) for DSR flexibility
reactive technologies See: Reactive Tradenergy website	DSR flexibility for businesses, NG scheme, 'Tradenergy' platform
REstore See: REstore website	'FlexPond' DSR flexibility for industrial consumers through IoT
V P S Virtual Power Solutions See: VPS website	Aggregation from individual buildings into VPP. Kiplo, Kisense and Cloogy platforms
ukpowerreserve See: UKPR website	Aggregates flexible small-scale power generation/storage
upside See: Upside Energy website	Aggregates small-scale capacity and would look to be active in local flexibility markets

3.7.3 Summary of Aggregator Engagement

Following on from this initial research, phone interviews were conducted with a sample of the above Aggregators, to clarify the level of engagement of national level Aggregators with local, small-scale flexibility. Part of this engagement was to gauge the views of commercial Aggregators on the feasibility and value of the ECAS model, or any similar service which could provide a platform for community scale actors to participate in local or national flexibility markets.
Phone interviews were conducted with representatives from three different Aggregators across June. The purpose of these phone interviews was to obtain perspectives on:

a) Their activity in aggregating small-scale flexibility
b) What are the barriers to aggregating domestic flexibility?
c) Are there financial benefits for homeowners and an existing model to share income and risk?
d) Would a service that bundles domestic flexibility (i.e. ECAS) for Aggregators or DNOs be valuable?

Graham Oakes upside

Graham was confident that a service providing a platform for households and communities to interface with local and national flexibility markets is feasible – either a peer-to-peer localised flexibility model or households and communities interfacing with the wider system – but it needs buyers and sellers.
Key points:

- An ECAS is feasible using a cloud service although a barrier could be the duration of flexibility required
- The main barriers are regulatory as the system is not configured to do this and there is no widespread existing model for:
    - peer-to-peer trading cutting across electricity suppliers
    - DNOs to engage with households using real time data
    - how to share the income between the homeowner, Aggregator, supplier and DNO
- Financially, flexibility could be worth around £100 per kW, but it depends on how the value is captured
- An ECAS would be valuable, especially for DNOs in constrained areas, but process and operational standards need to be developed.

Richard Hardy KiWiPOWER demand management

Richard was also confident that such a service will soon be feasible, with KiWi already looking into residential batteries and the flexibility they can provide. Key points:

- The cost of domestic installation makes the business case marginal as it's not cost effective per KW of domestic flexibility
- Other barriers are regulatory such as the framework for domestic billing
- Shifting demand and consumption is potentially valuable to homeowners but it needs a suitable variety of tariffs beyond Economy 7
- Constraint management is an important emerging market that suppliers and DNOs are looking into, in anticipation of EVs
- The Aggregator would finance the installation of technology and charge a management fee but wouldn't own the technology
- Suppliers may be reluctant to get involved due to domestic contracts and a lack of long term guarantee of domestic clients.

- An ECAS model would be valuable, but Kiwi are looking to enter the market themselves and wouldn't wait for such a service to bundle domestic flexibility loads for them.

Alex Howard

origamienergy

Alex was the least confident of the three Aggregator representatives about the feasibility of an ECAS, at least in the short to medium term. Key points:

- Research suggests there are benefits, but local flexibility markets don't currently exist, and there aren't many financial incentives
- Metering and retrofitting issues in homes mean the cost of installation and participation may put homeowners off as the market currently stands
- Households may be willing to participate for moral reasons, with little risk to the individual as it's taken on by Aggregators and DNOs
- There are promising isolated innovation projects such as Piclo and Centrica which are pushing DNOs to be more approachable
- Origami are working on a project attempting to configure a smarter system where local actors can trade amongst themselves and the DNO can intervene in an area where the network is struggling with new housing developments
- There are easier routes to scale than the residential and community level for aggregating flexibility which have not yet been exploited, Origami are mainly focused on C&I level actors
- For an ECAS to feasibly operate within a local flexibility market, there must be plenty of willing participants in a given area, with an application program interface into the system for households and communities allowing smaller actors to participate

3.7.4 Conclusion and considerations for ECAS

From these discussions and reviewing the publicity of many other Aggregators, some key considerations can be drawn in respect to the potential feasibility of an ECAS service:

- Many Aggregators are already exploring the opportunities in smaller scale aggregation and entering local markets fuelled by the uptake in smart appliances

- The current framework is not configured to accommodate small-scale providers of flexibility accessing revenue streams, and there are many regulatory barriers to them being able to access this value

- Another key barrier is the level of smart equipment required in individual households

- Some propose developing market platforms as a route to enabling peer-to-peer trading led by innovation projects

- Most see the value of an ECAS, some would choose to bundle domestic loads themselves, while others are sceptical of its efficacy within the current system and regulatory framework

3.7.5 The regulation of Aggregators

Ofgem consultation

Ofgem are of the view that permitting independent Aggregators (those that do not also act as suppliers) to gain access to additional markets can deliver benefits to the consumer, under carefully designed regulation[48]. This can be aided by ensuring a level playing field in the access to markets for participants, which will lead to greater competition, while the balancing costs and delivery risks should be the responsibility of the Aggregator and not the customer. They also say that payments for sold-on energy should be agreed in the retail contract between the supplier and the household level consumer, but they anticipate lessons to be learned once such arrangements become more widespread.

Such lessons are already being implemented with Ofgem's decision to grant derogation to Limejump[49], allowing it to participate in National Grid Balancing Mechanism (BM) scheme by submitting aggregated data at a Grid Supply Point (GSP) group level, rather than down at the single GSP level. These developments follow a consultation from Ofgem last year, as the potential for Aggregators to access the BM starts to become a reality, with Flexitricity potentially following suit.

ADE Code of Conduct

The Association for Decentralised Energy (ADE) is in the process of developing a Code of Conduct for Aggregators, in order to help build confidence amongst DSF providers and advance flexibility opportunities[50]. This Code of Conduct will be mainly targeting these four areas of the market:

- sales and marketing, ensuring an honest and technically proficient relationship between Aggregators and customers, allowing customers to make decisions based on accurate information to promote high performance in the industry
- technical due diligence and site visit, ensuring the best practices to protect data and assets from cybercrime, as well as requiring that member installations be built to ensure protection of employees and liability coverage in the event of an accident
- proposals and contracts, requirements that tenders are fair and accurate, with benefits and risks clearly laid out so as not to deceive customers into signing up for services they do not want or need, enabling Aggregators and customers to enter into mutually beneficial agreements
- complaints, requiring members to give continued support to customers after a contract has been signed, helping disputes to be resolved in a timely and attentive manner.

The code is being developed by a committee of Aggregators, suppliers and industrial customers. It will be voluntary and industry-led, developed by a committee of Aggregators, suppliers and industrial customers, due to be implemented later this year[51].

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48 https://www.ofgem.gov.uk/system/files/docs/2017/07/ofgem_s_views_on_the_design_of_arrangements_to_accomodate_independent_Aggregators_in_energy_markets.pdf

49 https://www.ofgem.gov.uk/publications-and-updates/decision-further-limejump-energy-limited-s-request-derogation-under-standard-condition-111-compliance-grid-electricity-supply-standard-licence-conditions

50 http://powerresponsive.com/wp-content/uploads/2018/02/Power-Responsive-Annual-Report-2017.pdf

51 https://www.theade.co.uk/news/ade-news/ade-demand-side-response-code-of-conduct-consultation

3.8 The growth of energy storage – key flexible technology

As an inherently flexible energy technology that can act as demand (when 'charging') or a generation (when 'discharging'), energy storage (particularly solid-state battery based) has seen a significant level of interest and investment in recent years. The level of interest to connect battery storage projects to the electricity networks has, for example, been unprecedented. Regen's analysis of storage connection data on the distribution shows that for 8 out of the 14 electricity licence areas, there are 200 projects, totalling over 4 GW of capacity now with an accepted connection agreement or online and operational, see Table 9. In addition to this, the UK transmission network has 2.7 GW of connected pumped hydro and 7 additional energy storage projects that are seeking to connect, as a mixture of battery and pumped hydro, totalling 2.5 GW - see. The near-term pipeline of new, largescale flexible energy assets in the UK is therefore significant and likely set to grow even further.

Table 9: DNO energy storage connection data
Sourced from WPD (June 2018), UKPN (Feb 2018) and NPG (May 2018)

	Accepted		Connected	
DNO	Number of Sites	Capacity (MVA)	Number of Sites	Capacity (MVA)
WPD	96	1,469	12	52
UKPN	53	1,441	6	89
NPG	30	1,070	3	4
TOTAL	**179**	**3,979**	**21**	**145**

Table 10: Transmission energy storage connection data
Sourced from National Grid Transmission Entry Capacity (TEC) Register (May 2018)

	Built and Operational		Under Construction/ Commissioning		Consents Approved		Scoping	
DNO	Number of Sites	Capacity (MVA)	Number of Sites	Capacity (MVA)	Number of Sites	Capacity (MVA)	Number of Sites	Capacity (MVA)
Battery Storage	0	0	1	138	0	0	1	25
Pumped Hydro	4	2,744	0	0	2	822	1	1,500
TOTAL	**4**	**2,744**	**3**	**138**	**2**	**822**	**1**	**1,525**

An up to date value of domestic storage deployment is largely unknown, but with up to 1,500[52] installations as of late 2016, the number is likely to still be very low, due to relatively high cost vs low/uncertain rewards for homeowners.

[52] REA estimated at least 1500 residential batteries had been deployed as of October 2016, see *Energy Storage in the UK – An Overview (October 2016)*: https://www.r-e-a.net/news/new-data-shows-extent-of-existing-energy-storage-deployment-and-planned-projects-in-the-uk

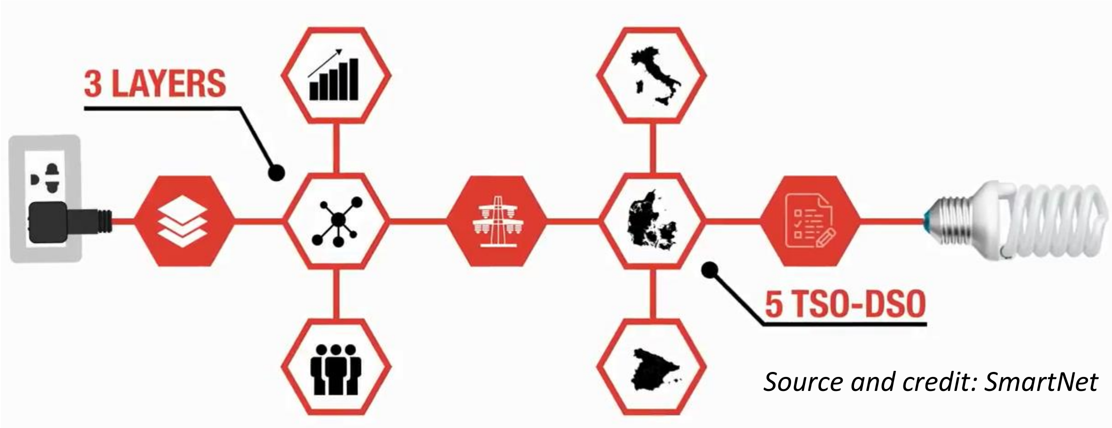
3.9 Overview of European Case Studies

A number of examples of enacting flexibility to mitigate local network constraints exist in European markets. Some examples are described below.

SmartNet **2016 – Ongoing**

http://smartnet-project.eu/

SmartNet is a three-year project funded by the Horizon 2020 programme, involving 22 partner organisations from nine European countries, including TSOs, DSOs, universities, research centres, manufacturers and telecoms companies. It is a modelling project focussed on exploring five TSO←→DSO coordination schemes around three case study nations: Italy, Denmark and Spain. The project is lab-based, simulating the physical network, the market, new players and ICT architecture.



Source and credit: SmartNet

A Danish case study explores the role of thermal inertia as a source of flexibility, testing the effectiveness of using price signals to control heated swimming pool thermostat levels in 30 rented summer houses. Laboratory testing and implementation was carried out in 2016 and a full demo of ten houses is ongoing since early 2017. The pilot focuses on system balancing and is operated by a 'bidding and clearing' procedure operated by a market operator (MO), which is distinct from the DSO or TSO and can be likened to the role of a UK flexibility market platform operator.
The process is as follows:

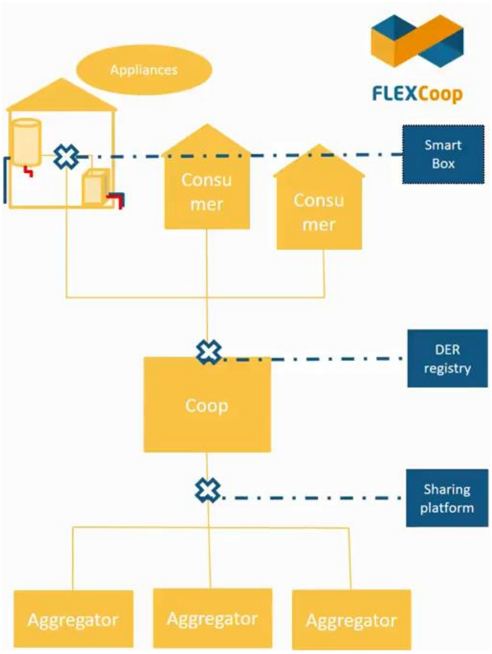
- The MO receives grid status information from the DSO and TSO and interacts with commercial market parties (CMPs) to gather the required flexibility
- The CMPs use a flexibility model that predicts electricity demand as a function of prices and sends out prices and price forecasts which aim to balance the grid for the coming hours
- Prices and price forecasts are received by a technical Aggregator, who calculates an optimal set point for individual thermostats based on price, weather data and booking information
- Data from the summerhouses is then collected to feedback into flexibility model

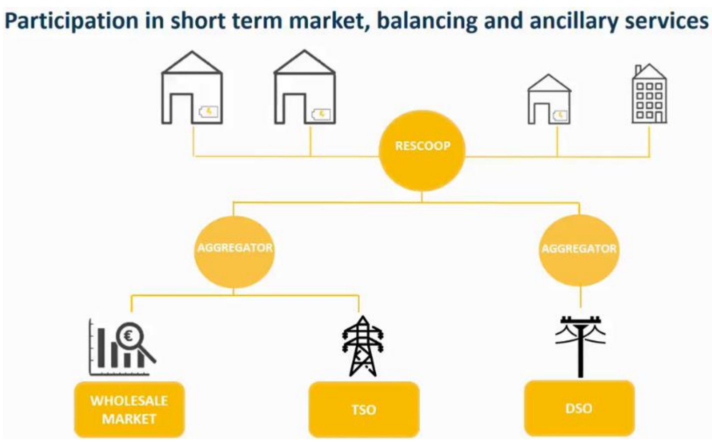
If the summerhouses were exposed to dynamic price tariffs and the smarter thermostatic control enables more efficient heating of the pool, there could be notable benefit to the owner/operator of the pool. The project is ongoing and results are expected to be published in 2018.
Key points:
i) Thermal inertia is potentially a strong small-scale flexibility resource, due to resilience to short-term calls to switch off/on. But fairly unique to heated swimming pools, so very limited opportunity.
ii) Automatic control of thermostat set point based on price, creates two-fold benefit from both the benefits of price arbitrage and from energy/heating efficiency benefits

FLEXCoop **Ongoing**

http://www.flexcoop.eu/about-flexcoop

FLEXCoop is another Horizon 2020 funded project to develop an automated demand response framework for domestic consumers. Its aim is to develop a suite of tools which together, form a demand response optimisation framework, allowing energy cooperatives to become Aggregators and exploit consumer flexibility to provide balancing and ancillary services to system operators. Launched in January 2018, the project is targeting an end-to-end approach, from smart box devices in the home, to a DER registry for energy co-ops to bundle, through to sharing platforms to interface with flexibility Aggregators.





Source and credit: FLEXCoop Consortium 2017-

The system operates by implementing an Open Smart Box (OSB) in the home to collect individual household information, from household DERs such as controllable electric boilers, dimmable lighting, heat pumps and EVs. This data is sent to the local demand manager, which calculates available flexibility (taking into account consumer preferences). The cooperative/Aggregator then collects information from all DERs and communicates to a global flexibility manager, which calculates overall flexibility available depending on grid and market dynamics. This aggregated flexibility is then made available to all potential users (including DSO and TSO) through an open market.

These tools are very similar in concept to the ECAS approach, ensuring end to end interoperability, enabling information to flow from consumer devices to Aggregator systems. In this approach, local energy cooperatives have the opportunity to exploit new revenue opportunities by optimising supply and demand at a local level, to minimise its imbalance exposure and to sell services to the network. Individual energy consumers can also potentially receive new revenue streams, by enabling them to participate in flexibility markets with smaller scale aggregation.

The project is also exploring the concept of a ‘microgrid-as-a-service’ solution, where a local energy cooperative could manage local generation, balancing and distribution infrastructure for consumers.

Key points:

i) Currently very early stages of the project with no published results as yet.

ii) Many synergies with the approach for the ECAS model, but reliant on a local energy co-op being in place already, which references UK community energy groups.

NICE GRID
UN QUARTIER SOLAIRE INTELLIGENT **2012 – 2016**

One of the six demonstrators under the GRID4EU project (co-funded by EU 7th Framework Programme for research, technological development and demonstration), Nice Grid is a project based in Carros, France. The trial focuses on the potential for network-connected microgrids to increase reliability and manage grid congestion. Community level demand response was tested through the provision of five offers (three in the summer and two in the winter):

1) Solar Bonus Offer: Over 40 days in 2014 and 2015, volunteer households were sent texts and/or emails a day ahead, asking to shift their energy demand towards time of high solar output between 12pm and 4pm, effectively falling under their supplier's (EDF) off-peak tariff, which usually only applies to overnight hours. Volunteers who responded were compensated with gift vouchers. This approach has similarities to the Sunshine Tariff project, where Regen worked with WPD, community energy group Wadebridge Renewable Energy Network (WREN) and supplier Tempus Energy.

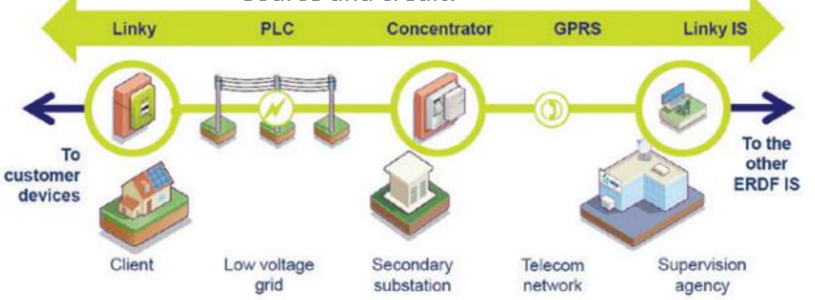
2) Smart Water Tank Offer: A group of participants agreed to have remotely controlled hot water tanks installed in their homes, that were switched on when local solar generation was available.

3) Smart Solar Equipment Offer: PV and domestic batteries offered to volunteers for remote control

4) Behavioural Load Management: Households were incentivised, again through gift vouchers, to reduce their consumption during the 6pm-8pm evening period, across 20 peak demand days.

5) Electric Heating Control: Household electric heating was programmed to be turned off, using Linky Smart Meter interface and controls, during peak demand periods. Customer heating/comfort was not compromised.

Source and credit:



Key points:

i) Experiments were positively received

ii) Regarding summer offers:

- 76 households took part
- Smart water heater households reduced demand by an average of 56% on a solar day
- Participants in the solar bonus trial reduced demand by 22% on eligible days
- Main motivators were stated to be the financial benefits on offer for shifting consumption, the environmental benefits and the desire to cooperate with the community to enhance the security of their supply.
- Use of text/email alerts was deemed as unpredictable and not a strong constraint/trigger to enact demand reduction.
- The presence of someone at home contributed to how much consumers were able to engage with the offer and respond to alerts.

iii) Regarding winter offers:

- Behaviour was mostly changed through changing washing machine and dishwasher usage patterns, and to lesser extent cooking appliances.
- 220 households took part, reducing consumption during peak periods by an average 21%

iv) General point that incentivisation through the use of e.g. gift vouchers, may limit participants and longevity/sustainability of behavioural change.

Carbon Co-op

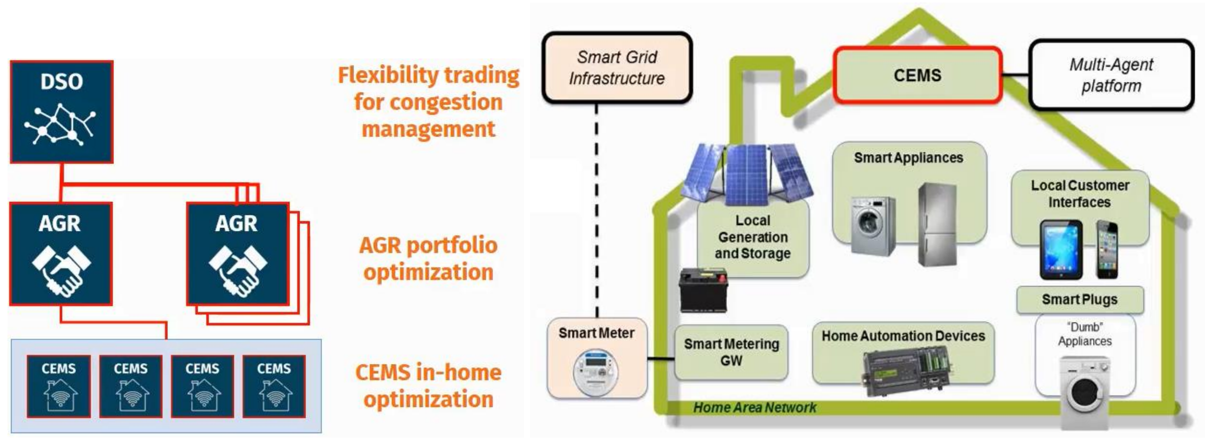
regen transforming energy

Mas²tering

2014 – 2017

A three-year consortium project to develop and test an ICT platform for the monitoring and optimal management of local community prosumers. **MAS^{2}TERING** (**M**ulti-**A**gent **S**ystems and **S**ecured coupling of **T**elecom and **E**nergy g**R**Ids for **N**ext **G**eneration Smartgrid Services). The project aimed to validate the technical and business viability of residential flexibility management, using a Multi Agent Systems (MAS) approach to decision making. It should be noted that the platform was tested using ENGIEs test facilities, which consisted of two buildings and a smart building, thus is not wholly representative of a local smart energy community.

Data on prosumer demand and generation output is collected and shared with the network via a home energy box device. Historical data is stored. Day-ahead forecasts of individual generational output and non-adjustable loads are predicted using this information, along with weather forecasting and social variables the participant families. This information is then made available to local Aggregators, in order to carry out local system balancing and the DSO to manage overall distribution constraints. The USEF market framework is employed as the overarching model, for the trading and commodification of residential energy flexibility in this case.



Key points:

i) Prosumers were able to self-optimise, setting the parameters of their home area network (HAN) in order to utilise low energy prices or maximise use of local generation, by automating the use of their devices available for flexibility.

ii) Local flexibility Aggregators were able to build portfolios of flexibility prosumers and carry out local

optimisation, engaging prosumers with DSO flexibility incentives. Aggregators were also able to carry out local system balancing and trading surplus local generation with other communities.

iii) The negotiation protocols by which Aggregators can draw on prosumer flexibility, are pre-set by the prosumer using his energy box.

iv) DSOs were able to monitor and analyse the network, providing dynamic incentives for flexibility that, through Aggregators and self-optimisation of HANs, help to reduce network constraints and potentially defer investment

v) Ultimately, DSOs could use the platform to aggregate proposed plans of local Aggregators and highlight potential network constraints. Flexible incentives could then be based on this information.

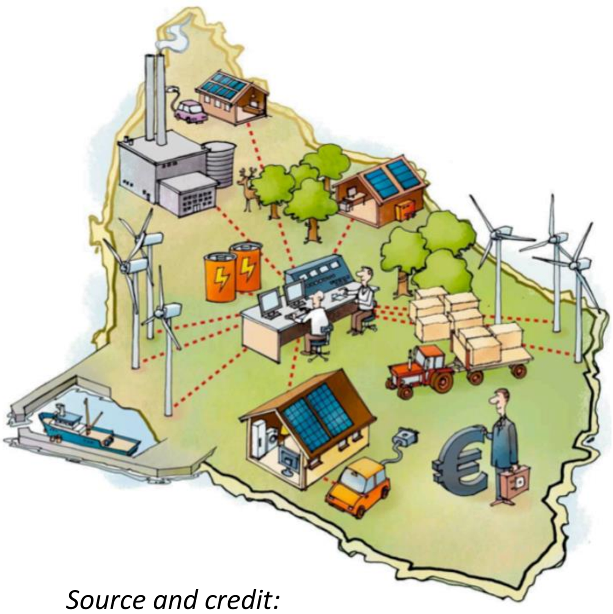
vi) Intra-day optimisation was further tested by running simulations for one section of the low voltage (LV) Belgian network, defined as a local energy community. Whereas simulations of part of the Cardiff LV network tested day-ahead optimisation capabilities over a wider network area.

vi) The project was successful in proving that the platform could accurately forecast and manage signals to control load profiles in a cyber secure way. The project estimated that if implemented, the MAS^{2}TERING system could reduce European grid losses by 5-8%, potentially reduce DSO reinforcements to up to €28 billion and increase the penetration of local renewable

EcoGrid eu
www.eu-ecogrid.net **March 2011 – August 2015**

http://www.eu-ecogrid.net/

The EcoGrid trial was carried out on the Danish Island of Bornholm and demonstrated the operability of smart grids by using real-time pricing signals by grid operators. Flexibility was realised through either manual customer engagement or automated devices. The trial also tested the ability of Aggregators to control a portfolio of customer devices. This system varies from many other examples and trials, as it reduces the need for a direct flexibility market, instead the actors respond to real time price signals that are updated every five minutes.



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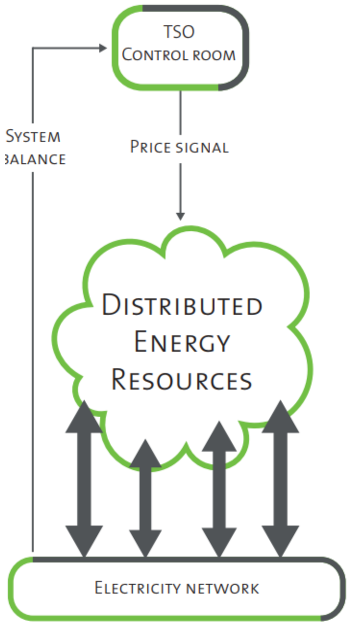


Source and credit:

Key points:

i) A real time price signal can be used to activate flexible consumption
ii) Activation of flexible demand via price signals, reduced peak load of participants by 670 kW (1.2%)
iii) Households with equipment that automatically controlled heating systems in response to price signals accounted for 87% of peak demand reduction
iv) Involving customers is the key to success and personalised advice is most effective
v) Standardised second generation smart grid equipment and metering is necessary

3.9.1 Key considerations for ECAS model

There are some lessons that can be drawn from reviewing these case study trials and projects, namely:

- Automatic control of domestic loads reduces the risk of non-response. Smart appliances, metering and communication devices are key enabling technologies to make ubiquitous domestic flexibility a reality.
- The level of reliable flexible load in a household is limited to certain appliances or those homes that have electric heating (electric boilers or heat pumps), home battery systems or EVs. Turning attention to electronic devices, chargers, computers etc. is likely to have a very limited effect.
- Aggregation can happen at more than one level and/or by different parties. Triggering flexibility at multiple households concurrently, can be seen as ‘bundling’ or aggregating demand response action, but many of the domestic flex projects listed have central platforms that interface with Aggregator parties and their own platforms. The principle of aggregation is therefore likely to be

a key route to market for smaller participants, occurring potentially more than once between a DSO call and domestic DSR action

3.10 Terms of Reference / Glossary

SO/TSO/ESO/NETSO: UK System Operator (National Grid), look after the electricity transmission network and system in the UK.

DNOs: Distribution Network Operators, the 6 regional companies licenced to distribute electricity within 14 defined licence areas across Great Britain.

DSOs: Distribution System Operators, the evolving role of regional DNOs to "*…operate and develop an active distribution system comprising networks, demand, generation and other DERs*"

DERs: Distributed Energy Resources, assets connected to the distribution network that could be called upon to provide flexibility services.

CMZ: Constraint Managed Zone, a discrete geographical area, likely related to an electricity substation supply area, where flexibility services may be required.

Flexibility services: Modifying generation and/or consumption patterns in reaction to an external signal for a financial reward (payment for the service delivered).

Revenue stacking: Using assets to access multiple incentive programmes, paid for services or contracts – i.e. both national balancing and local flex services.

Aggregation: 'Bundling' smaller loads into a portfolio, which can participate in programmes where entry thresholds are too high (i.e. 1MW for national balancing services, 100kW for local flex markets etc.)

4. ECAS Technical Feasibility Assessment

Author: Ben Aylott, Carbon Co-op

Content

This work package report is organised into three sections; a requirements analysis, an example system design based on a description of the high-level concept and use case, and an analysis of the example system.

4.1. Introduction

The development of local flexibility markets (and local energy markets more broadly) sits at a nexus of changes in the energy system, policy, and wider technology. There is an increasing amount of smart, generation, and storage assets (collectively referred to as Distributed Energy Resources or Active Demand and Supply) being connected to the distribution network, creating 'prosumers' who can store, generate, and reduce/increase power use. This resource is commoditized as 'flexibility' which can then be bought and sold by energy system actors. Local flexibility and energy markets are seen as a potential way of valuing and directing this activity to support energy system actors and the UK government in achieving their commercial, non-policy, and policy objectives.

Flexibility can be created in different ways with different implications for how it is valued and the technical systems needed. Implicit demand side response is price-led with prosumers basing their decisions about what flexibility they will provide to the system on the price of energy they are offered. The benefits of this in liberalised electricity markets is mainly economic e.g. improving market efficiency by allowing prices to better reflect supply and demand. It is also largely possible today with the first generation of smart meter-enabled electricity tariffs coming on to the market. Future reforms to charging could also support locational and temporal charging for use of network, enabling price signals to be sent by the DSO and ESO. The technical systems required to enable this type of demand response are ready now, relying only on the prompt 'broadcast' of price data to prosumer energy management systems (something achieved recently with the Octopus Agile API and supporting services) which can then determine an optimal schedule for operation of DER assets based on local requirements.

The other type of demand response is explicit demand response, where a flexibility provider is directly incentivised. The technical requirements of this type of demand response are higher, requiring more real-time systems targeting specific changing groups of flexibility providers and the automated exchange of information and negotiation between multiple actors followed by rapid dispatch of flexibility assets.

The focus in this study is on the feasibility of a market and technical concept (dubbed ECAS) for enabling explicit demand side response in a local flexibility market (local here meaning that its purpose includes supporting the activities of the DSO), with flexibility providers receiving payment for creating specific amounts of flexibility for different system actors (in the first instance the DSO, but potentially also suppliers and the ESO). This form of response can meet the operational requirements of DSOs and the ESO (such as capacity management and redundancy support) in addition to supporting the more traditional market-based economic objectives of suppliers.

The development of such systems is now well underway, enabled by parallel developments in mobile computing and electronic appliances towards increasing internet connectivity (the so-called 'internet of things') backed by cloud computing systems for rapid analysis of data and automated intelligent control (machine to machine communication). These developments will enable the cost-effective and reliable control of millions of devices required for creating an 'internet of energy'.

4.2. Requirements Analysis

3.10.1 Technical Standards

4.2.1.1. Role of standards

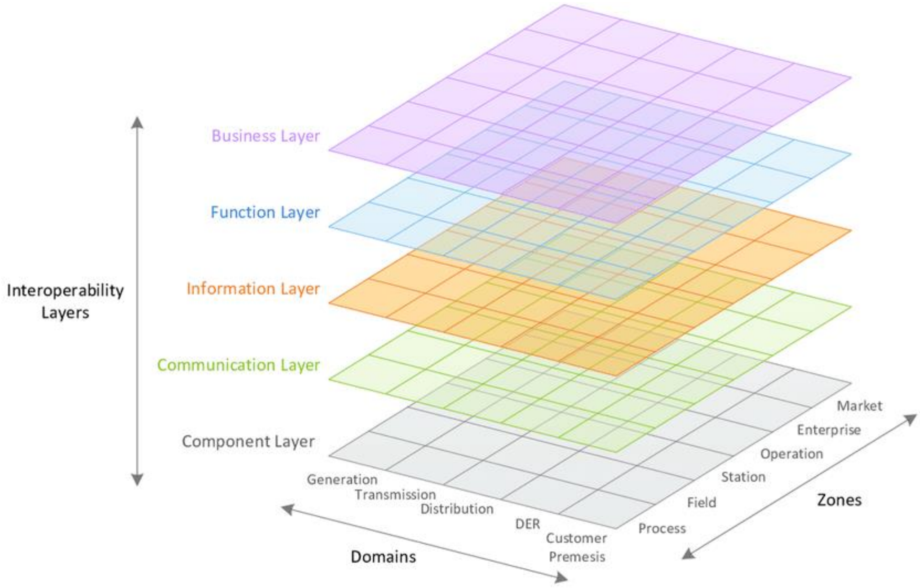
Electricity networks and markets are by their nature very complex and the application of technical standards serves to codify good practice and ensure critical systems in their operation and maintenance. The transition to a smart grid will bring further complexity including the need to exchange and operationalise large amounts of data from different parts of the system as well as support a much higher degree of interaction between business and information processes and more traditional operations. In order to achieve this there needs to be an increasing focus on interoperability in order to support the parallel and rapid development of new systems. For critical operational systems affecting grid stability and security there is no question that their operation should be carefully defined and controlled. But there is significant areas where standards should be sufficiently open, changeable, and flexible to facilitate innovation.

We have focussed here on the application of several complementary standards for the smart grid and local flexibility markets:

- Smart Grid Architecture Model (SGAM) which provides a framework and common language for the smart grid which enables use cases and business models to be mapped to the technical infrastructure.
- Universal Smart Energy Framework (USEF) which describes the mechanisms of local and national flexibility markets.
- OpenADR which specifies the information and control flow involved in the dispatch of ADS/DER/flexibility assets.

Our interest in promoting particular technical standards for the architecture of the smart grid and flexibility markets is in encouraging interoperability between systems. This lowers the cost (to end consumers) of integrating different systems through ‘plug and play’ operation and interchangeability of different manufacturers systems.

4.2.1.2. Smart Grid Architecture Model (SGAM)



The Smart Grid Architecture Model[53], developed by CEN, CENELEC, and ETSI under an EU mandate, is an attempt to create a reference architecture for future smart grids which captures the structure, information flows, and processes in a smart grid. This can be used to model and test high-level use cases (e.g. a local or national flexibility market) and help to identify deficiencies in process, functionality, interoperability, and information exchange. It has a high-level of correspondence with a similar US initiative by NIST[54]. However, SGAM necessarily reflects various differences between the EU and US electricity networks and markets, in particular SGAM incorporates the concepts of DER and flexibility.

The SGAM model splits the smart grid architecture in three conceptual dimensions. The first is the 'domain' which groups functions and processes by their relationship with traditional areas of the energy conversion chain such as generation, transmission, distribution, and behind the meter as well as the new class of DER. The second is zones which relates to the hierarchical levels of power system management. The plane formed by zones and domains is then divided into five 'Interoperability' layers which categorise business processes and objectives.

It is important to note that although SGAM can describe certain systems, information, and processes which may be involved in the operation of a local flexibility market (such as the format and content of information exchanged or the type of communication protocol between systems) it does not currently describe market mechanisms for energy or flexibility.

The relevance of SGAM to ECAS and local flexibility markets is:

- Its adoption by the EU (and the US through the NIST model) as a reference architecture for smart grid development.
- Its use in the ENA Open Networks project as well as various NIC projects in describing and modelling the operation of future UK smart grids and flexibility markets.

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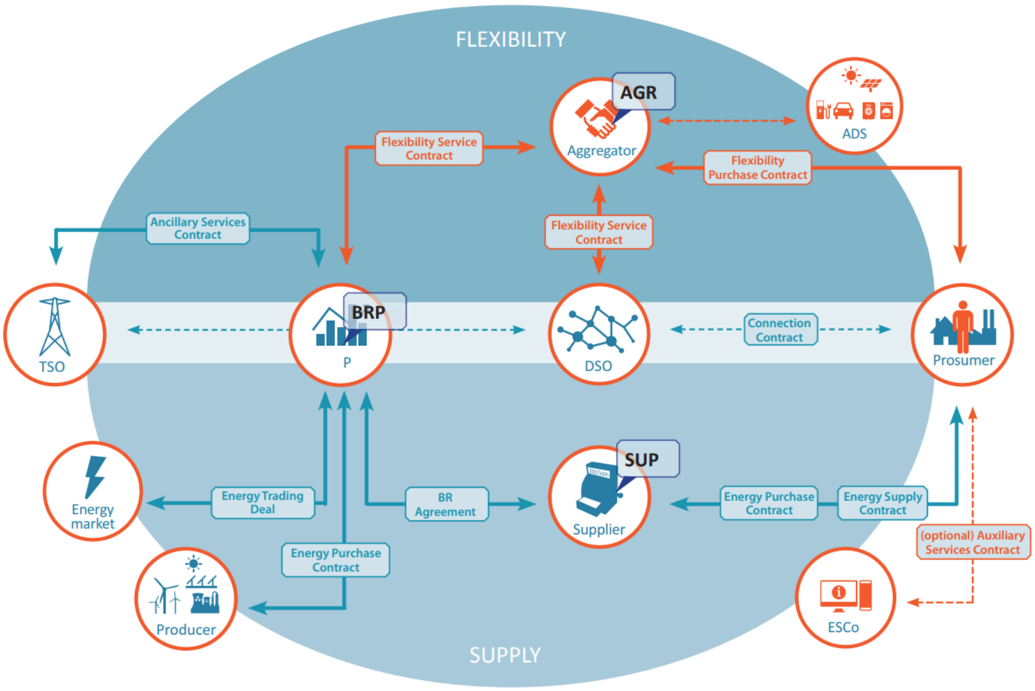
53 "CEN-CENELEC-ETSI Smart Grid Coordination Group Smart Grid ...." 8 Nov. 2012, https://ec.europa.eu/energy/sites/ener/files/documents/xpert_group1_reference_architecture.pdf. Accessed 21 Aug. 2018.

54 "NIST Framework and Roadmap for Smart Grid Interoperability." 3 Sep. 2014, https://www.nist.gov/document-2643. Accessed 21 Aug. 2018.

- Adopting a common language for smart grid architectures. By making reference and utilising the concepts and terminology used in SGAM it enables those working in other related domains (such as IT services, regulation, and policy) to more easily communicate and identify areas of common working. This is particularly important to the operation of future local flexibility markets where there is a high level of communication and coordination between DNO/DSO actors and platform providers, DER manufacturers, and Aggregators.
- The current lack of any real alternative. WIth the exception of the NIST architecture model (on which SGAM is partly based) there is currently no other major standards effort or mindshare in any alternative in the EU and North America.

Below we undertake an initial modelling exercise under SGAM for the ECAS system, describing the high level use cases and making a first mapping of these to different interoperability layers, zones, and domains.

4.2.1.3. *Universal Smart Energy Framework (USEF)*



The Universal Smart Energy Framework[55] is an open standard for describing the structure and operation of a local/national flexibility market. ECAS proposes a USEF-style local flexibility market which could be extended organically to incorporate additional local/national markets. Indeed, the potential economic value of flexibility is maximised when there is a single national (or even supranational) market for flexibility.

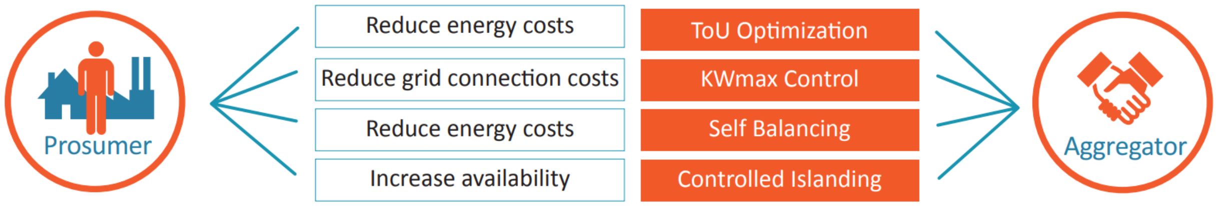
The value of a flexibility market is maximised when the impact of flexibility procurement is reflected in settlement through the participation of suppliers (who themselves can benefit from procuring flexibility to improve their position in different markets by e.g. reducing their imbalance risk). This is why it is important to plan for the inclusion of suppliers in local flexibility markets (many current discussions focus only on the participation of DSOs) and USEF facilitates this by enabling suppliers to easily join at a later date.

[55] "Universal Smart Energy Framework." https://www.usef.energy/. Accessed 21 Aug. 2018.

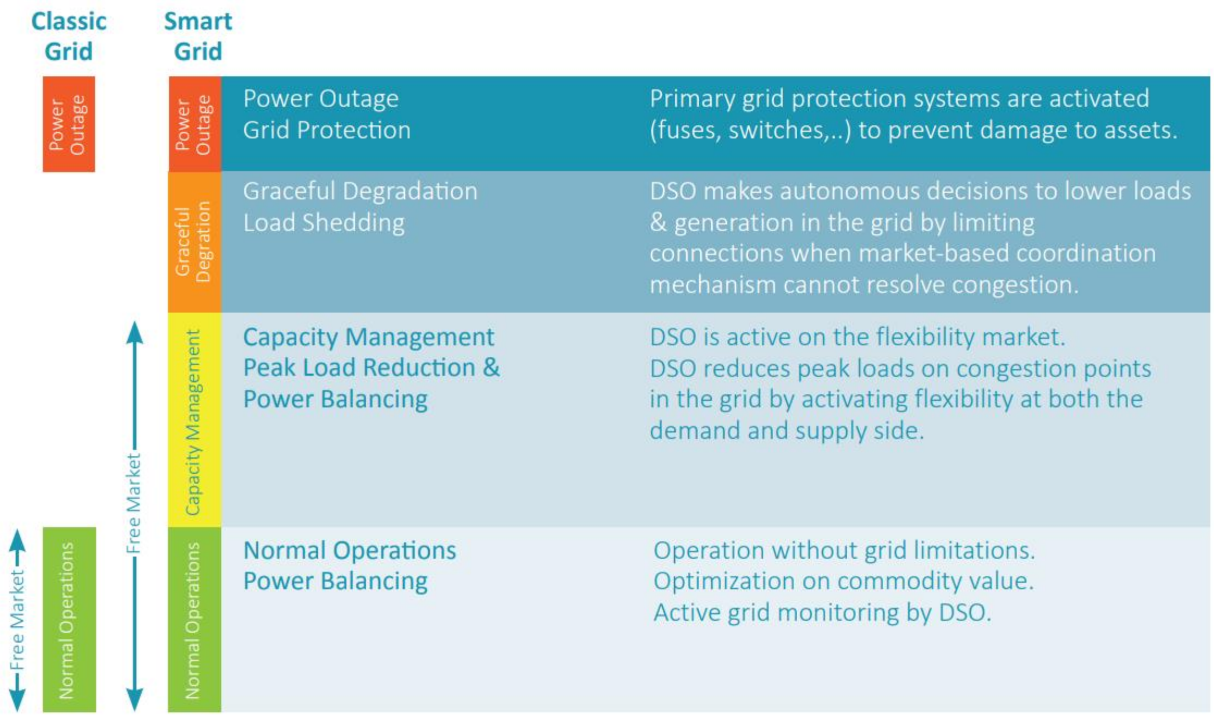
One of the benefits of the flexibility concept is that it can initially be developed in parallel with the existing electricity markets, starting with local markets for DSOs procuring flexibility and then linking these together to form a single national flexibility market which could eventually be able to supplant many existing ancillary services.

3.10.1.1.1 Key features of USEF Flexibility Markets

Central to USEF is the role of the Aggregator which acts as the intermediary between prosumers, communities, and other system actors. The Aggregator enters into bilateral agreements with prosumers, DSOs, and suppliers but there is a single market for flexibility through which all parties submit requests and offers for flexibility. Some of the use cases making up the value proposition of an Aggregator under USEF are depicted in the below figure.



In a traditional grid, markets are applied to non-critical/economic operating regimes such as wholesale and balancing. A USEF local flexibility market also supports peak load reduction and capacity management in the distribution network. This can also be extended in a future smart grid to redundancy support and controlled islanding (of microgrids). More critical operating regimes relating to grid protection and preventing outages continue to take priority over market-based operations. This extension of markets to other operating regimes is depicted in the figure below.

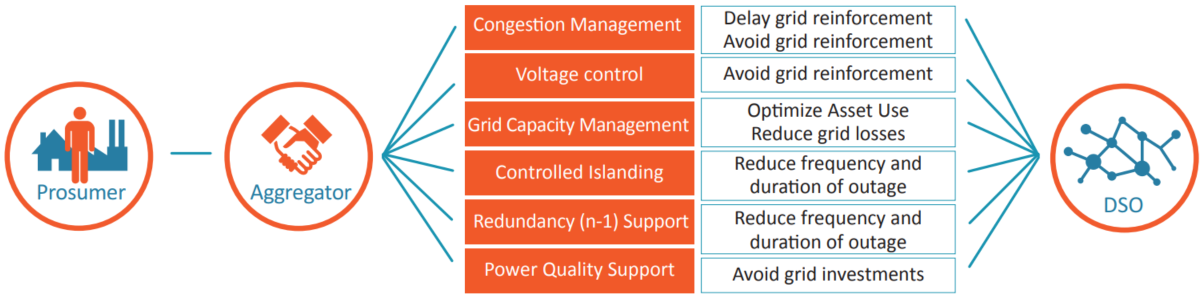


The way that USEF performs this segregation between market/non-market is through a 'market coordination mechanism'. This single process allows for both market and non-market operations to be integrated. This is divided into several stages during which different actors establish their requirements and what they can offer subject to economic and operational constraints.

Importantly, this market process allows for the sometimes competing needs of different actors to be rationalised. The fact that the needs of the DSO, ESO, and supplier are sometimes opposed is often overlooked in discussions around flexibility which assume the requirements of different actors are always aligned. This was demonstrated clearly in the first USEF pilot[56]. This suggests a price-based market mechanism would be more effective at valuing system flexibility (if the interests of all actors were aligned then non-market coordination maybe a better choice in system terms).

USEF links flexibility requirements to so-called 'congestion points' corresponding to a node in a logical graph representing the physical infrastructure of the electricity grid. This is similar to the concept of a 'constraint managed zone' as is currently used by UK DNOs however it applies to all points of common connection in a distribution network rather than a boundary at a particular level. The relation between congestion points, settlement, and DSO/prosumer parties is the 'Common Reference' and is maintained by a 'Common Reference Operator' (CRO). In a later section we outline how current and future UK systems can be combined/developed to form such a Common Reference.

USEF supports a wide range of use cases including all the ECAS use cases described below. The below diagrams illustrate the USEF use cases for the prosumer, Aggregator, and DSO in a local flexibility market. There are additional use cases for the supplier/BRP and TSO which may also be relevant to the future development of the market (or other markets).



4.2.2. Relation to UK market context

USEF has been designed to be sufficiently general so it is applicable to current and future European market contexts and it is straightforward to map this to the current UK market context. The main difference between the USEF default model (as presented in reference documents) is the explicit separation of the BRP and 'supplier' roles - in the UK these are currently combined in the supplier. Reforms to balancing market access proposed for introduction in 2019 and future changes to wholesale market access will make this distinction more relevant in the UK. In the event of the 'supplier hub' approach ending, a separation of the BRP functions could be one way forward and it would arguably open up the retail, wholesale, and balancing markets to more competition.

Another largely semantic distinction to current UK market roles is that of TSO (USEF) and the Electricity System Operator (ESO). This is partly a reflection of the different roles of transmission operators in the wider European market. In the UK, National Grid currently plays the role of TSO but is being split up into

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[56] "Flexibility from residential power consumption - Universal Smart ...." https://www.usef.energy/app/uploads/2016/12/EnergieKoplopersEngels_FinalReport_2016_vs4-1.pdf. Accessed 11 Sep. 2018.

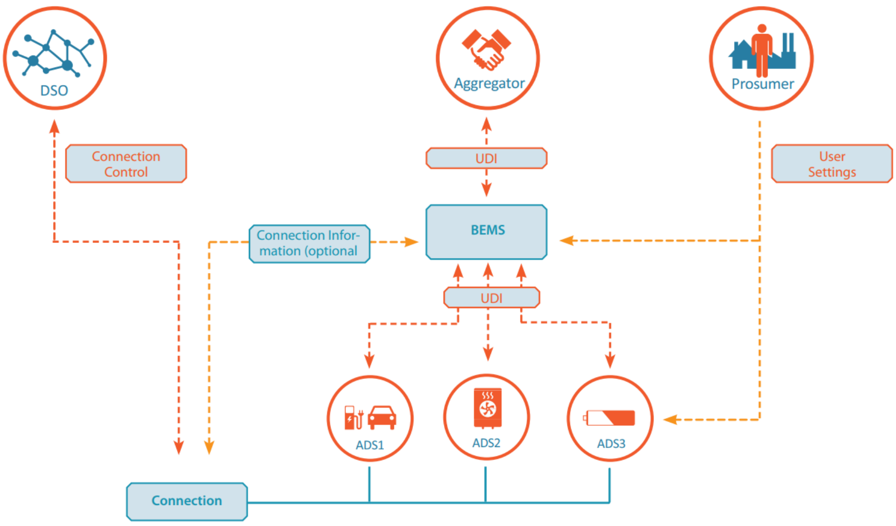
an ESO (Electricity System Operator) and ETO (Electricity Transmission Owner). The new ESO role maps well to the USEF TSO role.

In the standard model of USEF, Aggregators do not contract directly with the TSO to provide flexibility but go through the BRP instead. In the UK currently Aggregators contract directly with the ESO and the UK government for providing ancillary grid services and (in a more limited sense) strategic capacity. This will make market coordination more complex (effectively more 'Plan' / 'Operate' / 'Validate' stages would need to be added). Another possible route would be to allow UK Aggregators to effectively become BRPs with independent access to balancing and wholesale markets. This is not so far away from the recent decision to grant Aggregators access to the balancing mechanism. Whichever route is pursued USEF allows for such differences between national markets and the picture can be redrawn to show a relationship formed with either these parties or an intermediary.

The USEF framework roles do not contain an explicit definition of a market platform (which we have included in ECAS). A market platform can be seen to take on a number of roles in USEF or simply act as an equipment provider.

The USEF framework describes a 'meter data company' (MDC) and 'allocation responsible party' (ARP). The MDC role and some of the ARP role will be played by the DCC (part of the UK smart metering system). We envision that other aspects of the ARP role would be played by the market platform or similar.

4.2.3.ADS Control using OpenADR



USEF does not apply to the control of ADS (USEFs terminology for DER or flexibility assets) although it does outline (see diagram) in a 'USEF Device Interface' (UDI) how it envisages this working within the market context. To aid conceptualisation of the way the market would operate we have chosen to describe the ADS system in terms of OpenADR which is an open royalty free standard for control of ADS/DER which has been mandated for use in HVAC and other systems in California. The OpenADR Alliance and USEF Foundation have signed an MoU stating their intention to harmonise the operation of the two standards. The two standards have many synergies and a similar philosophy in promoting a vendor neutral approach to smart grid solutions based in open internet technologies. However, an alternative standard could be used without unduly affecting the operation of ECAS.

4.2.4.Other regulations and standards

There are a plethora of engineering, regulations, and other standards covering specific smart grid physical, functional, business, and information domains. We reference the most important and relevant of these below with some comment on how they may be applied in ECAS:

- Data Protection Regulations (EU GDPR/UK Data Protection Acts)[57]: Due to the large amount of data which will be collected by ECAS it is likely that there will be issues around anonymisation/pseudo-anonymisation of data and data minimisation as well as consent (although not all uses of personal data will rely solely on consent in the context of providing a flexibility service to consumers). Some of this could be mitigated using technical measures such as aggregation of data and edge computing (i.e. high resolution data is not transferred or processed outside of the home network). There is also a legal requirement under the GDPR for companies to implement 'Data protection and design by default'.
- Zigbee SEP 1.x[58]: One of the main technical standards underpinning the UK smart metering system. Aggregator systems will need to interact with smart metering devices to obtain metering and tariff data and may need to be 'aware' of this. Zigbee SEP 1.x also incorporates some functionality for control of DER assets.
- SMETS, DUIS, and Smart Energy Code[59]: Standards relating to the technical requirements, operation, and governance of the smart metering system. ECAS will interact with the system through the DCC (specifically the DUIS system) and using SMETS compliant CAD devices. Cybersecurity is covered in far more detail in the current standard than
- IASME[60]/ISO 27001/ISO 27002: These standards cover information assurance and management and implementing them may help in managing the cyber security risks posed by the operation of a flexibility market. The appropriate standard depends on the size and activities of the organisation. These only provide a high-level framework to enable the effective management of information security risk and will need to paralleled by effective standards in implementation.
- IEC 62056: Describing DLMS/COSEM as well as various communications with smart meters. UK smart meters produce data in this format and so intermediate systems (such as the Aggregator) will either need to understand it or be able to transform it.
- IEC 61970 / IEC 62325: Standards describing the Common Information Model (CIM) and specific extensions to this for deregulated electricity markets in Europe which have been adopted by ENTSO-E. Again, although the details of this is likely to be abstracted, various ECAS sub-systems (such as the market platform) may need to deal with information transmitted in compliant formats.
- IEC 61850: A widely promoted standard for defining communication protocols at substations and automation of substation control which is likely to be heavily utilised in the future UK smart grid. Although the details of this are likely to be abstracted by intermediate DSO systems it is possible that the common reference operator (CRO) may need to exchange information

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[57] "Data Protection Act 2018 | ICO." 25 May. 2018, https://ico.org.uk/for-organisations/data-protection-act-2018/. Accessed 28 Aug. 2018.
[58] "Smart Energy | Zigbee Alliance." https://www.zigbee.org/zigbee-for-developers/smart-energy/. Accessed 28 Aug. 2018.
[59] "Smart Energy Code: SEC." https://smartenergycodecompany.co.uk/. Accessed 28 Aug. 2018.
[60] "IASME." https://www.iasme.co.uk/. Accessed 28 Aug. 2018.

according to this standard and may provide information in context when publishing information about congestion points etc.

4.2.5. Existing commercial providers/alternatives

No existing commercial provider advertises a USEF-compliant system but below we highlight how a selection of existing services could be developed to provide different parts of a USEF flexibility market.

4.2.5.1. Piclo Flex

The Piclo Flex[61] platform is a new service from Open Utility which is aimed at simplifying the process of matching DER assets which can provide local flexibility to the requirements of DNOs looking to procure it. DER assets are registered on the platform and these are then periodically submitted to DNO local flexibility tenders. The service does not currently undertake any dispatching of DER assets or include other flexibility markets, although these are both on the roadmap for development. In the context of ECAS, the service could play the role of the market platform and/or provide the DSO interface under USEF, however this would require further development.

4.2.5.2. Moixa GridShare

Moixa manufactures and supplies integrated home battery systems and optionally connects these to GridShare[62], an Aggregator platform service which pays homeowners for allowing their batteries to be remotely controlled (currently believed to be a loss leading activity as most flexibility markets are still not open for participation from aggregated domestic loads). There is some suggestion this is compatible with other third-party DER assets although a list of compatible products is not published. The functionality of GridShare overlaps substantially with the described ECAS Aggregator platform and could play that role subject to the addition of a USEF compatible Aggregator interface and any additional business logic required.

4.2.5.3. Upside Energy

Upside Energy[63] have developed an Aggregator platform dubbed the 'Virtual Energy Store'. This platform in many ways seems to be the closest in vision to the ECAS Aggregator and is one of the only alternatives with a clear aim to engage domestic customers. By providing suitable USEF compliant interfaces, the Upside service could play the role of either the market or Aggregator platforms in ECAS.

4.2.5.4. WPD Flexible Power Participant API

WPD's 'Flexible Power' local flexibility scheme provides a REST API[64] which will be used for sending requests to those providing flexibility. The paradigm for communication and control between actors represented by this (using IP networks and standard internet protocols to peer requests) is the same as that used in USEF and this could be easily developed to provide a USEF-compliant interface (for DSO).

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[61] "Piclo Flex Summary - Power Responsive." http://powerresponsive.com/wp-content/uploads/2018/05/OpenUtility-Piclo-Flex-Summary-May-2018.pdf. Accessed 28 Aug. 2018.

[62] "Make Money Selling Electricity with Moixa GridShare : moixa." http://www.moixa.com/products/gridshare/. Accessed 28 Aug. 2018.

[63] "Upside Energy." https://upsideenergy.co.uk/. Accessed 28 Aug. 2018.

[64] "Flexible Power Constraints Manager." https://flexiblepowerwpd.co.uk/. Accessed 28 Aug. 2018.

4.2.5.5. *Electron*

Electron have developed a flexibility market platform[65] based on blockchain technology. This could play the role of the market platform in an ECAS scheme with the addition of an appropriate USEF-compliant interface.

4.2.5.6. *Centrica Cornwall Local Energy Market*[66]

Provides a market platform with some Aggregator functionality for buying/selling energy and flexibility. Could play the role of the market platform in ECAS.

4.2.5.7. *Energy Local*[67]

Energy Local, in partnership with Co-operative Energy and others, have implemented a range of systems to support a local balancing trial in Wales. This does involve behind the meter control of flexibility assets using a HEMS in response to price signals. Some aspects of the HEMS and other back end system may be relevant to a ECAS Aggregator system.

4.2.5.8. *OpenLV*[68]

OpenLV is an innovation project to provide access to data from substations to approved third-party developers, businesses, and communities. The technology behind OpenLV could be applicable in the CRO systems in ECAS.

4.2.5.9. *Elexon BMRS*[69]

Elexon administers the BSC and provides a Balancing Mechanism and Reports Service (BMRS) which is widely used as an authoritative source of information about the electricity market. These services are similar to what would be required for the CRO and/or market platforms (although the volumes of data would be much greater).

Product / USEF Role	Aggregator Platform/Interface	Energy Market Platform	ADS	DSO Platform/Interface	CRO
Piclo					
Moixa					
Upside					
WPD Flexible Power Service					

[65] "Electron | Blockchain Systems for The Energy Sector." http://www.electron.org.uk/. Accessed 28 Aug. 2018.
[66] "Cornwall Local Energy Market | Centrica plc." https://www.centrica.com/innovation/cornwall-local-energy-market. Accessed 28 Aug. 2018.
[67] "Energy Local." 9 Dec. 2014, http://www.energylocal.co.uk/. Accessed 29 Aug. 2018.
[68] "Open LV | The groundbreaking project that's making local electricity ...." https://openlv.net/. Accessed 29 Aug. 2018.
[69] "What is BMReports.com? - ELEXON." https://www.elexon.co.uk/knowledgebase/what-is-bmreports-com/. Accessed 29 Aug. 2018.

Electron					
Centrica					
Energy Local					
OpenLV					
Elexon BMRS					

4.2.6. Cybersecurity and Data Privacy

The operation of a demand side response system at scale presents significant cybersecurity and information management challenges. Recent studies[70] have highlighted how even unpredicted changes of 1% of total demand (well within the anticipated levels of demand side response in a future smart grid) can cause costly frequency deviation, blackouts, and cascading infrastructure failure with consequent economic and national security implications. There are some circumstances in which the improper operation of assets could cause damage to those assets and increase the risk of fire or explosion and threat to human life. A range of state and non-state adversaries with a wide range of objectives could be motivated to conduct such attacks.

On the other hand, risk mitigation efforts should be proportional to the level of demand response under control which for the near future is unlikely to be large enough to pose any threat to grid operations. We note the proposed ADE Code of Conduct for Demand Side Response/Aggregators[71] contains a section on cybersecurity with some broad guidelines which should be a good starting point going forward but maybe become unsuitable when/if a large amount of load and devices are under control in domestic properties. There are several areas which are not covered:

- The proposed code does not recommend any information management standards (such as Cyber Essentials or IASME).
- Most guidelines focus on design, pre-emptive, and post-attack actions (both obviously important); but there is no discussion of the need for online incident detection which will be essential in stopping attacks in progress.
- There is no requirement to notify regulatory or government agencies (e.g. National Cyber Security Centre).

With the inclusion of these provisions we would judge the adoption and implementation of the Code of Conduct (or similar) to be an important (but not the only step) in mitigating the unique cybersecurity risks presented by demand side response systems.

Data privacy and the rights of data subjects has received increased attention due to recent high profile data losses and the introduction of new Data Protection Regulation (EU GDPR 2018/DPA 2018). Businesses are exposed to increasing financial and reputational risk as more of their operations are digitalised. Apart from the collection of personal information in the course of running typical business

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[70] "BlackIoT: IoT Botnet of High Wattage Devices Can Disrupt the ... - Usenix." https://www.usenix.org/conference/usenixsecurity18/presentation/soltan. Accessed 12 Sep. 2018.
[71] "Download ADE Demand Side Response Code of Conduct Consultation." 18 Jul. 2017, https://www.theade.co.uk/assets/docs/nws/DSR_CoC_Consultation_Document_-_Final_-_18_July_2017.pdf. Accessed 12 Sep. 2018.

processes, demand side response systems require access to real-time information about domestic energy usage which is of a potentially sensitive nature and in certain contexts and combinations constitutes 'personal information' as defined under the DPR. The new DPR contains requirements for 'privacy by design', data minimisation, and data pseudo-anonymisation and this will need to be explicitly considered as part of the architecting and design of the system.

It is the opinion of the author that demand side response systems benefit greatly from the use of IaaS cloud computing services (such as AWS) which impose beneficial architectural and design choices, and provide extensive guidance and tooling (often at no extra cost) which is of great assistance to cybersecurity and information management.

4.3. Example design and analysis of ECAS

4.3.1. USEF Aggregator Implementation Model

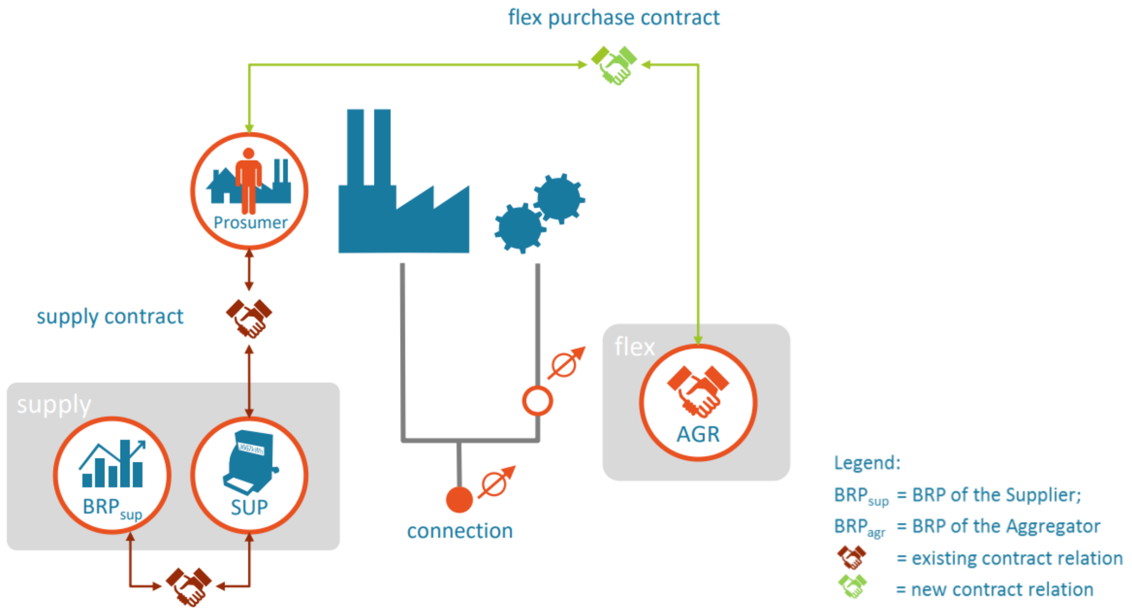
Our starting point in the design of the ECAS system is an aligned USEF use case description of the operation of ECAS in the context of settlement and balancing arrangements referred to as an 'Aggregator implementation model'. The USEF foundation has identified seven types of these models[72] which are classified according to the configuration of contractual relations between BRPs (suppliers in UK) and the Aggregator. The interaction between DSO and Aggregator is also important but it is simpler to model in the context of balancing and settlement.

When flexibility is 'activated' it causes imbalance for the supplier as well as incurring any energy costs from changes in the supplied volume. If the actions of the Aggregator do not take this into account this is (arguably) non-optimal for the system as the impact on balancing is not priced in. For this reason Aggregators in some European markets are required to appoint a BRP (or even be a BRP themselves), indeed the UK is one of the few markets where Aggregators operate without this requirement.

There are different ways the imbalance created by Aggregator operations can be resolved. Where the Aggregator and supplier are the same entity this is simple as the correction should not create an imbalance (unless due to error). We are concerned here mainly with 'independent' Aggregators who do not have supply licenses.

The situation where the activation of flexibility is 'uncorrected' is depicted below.

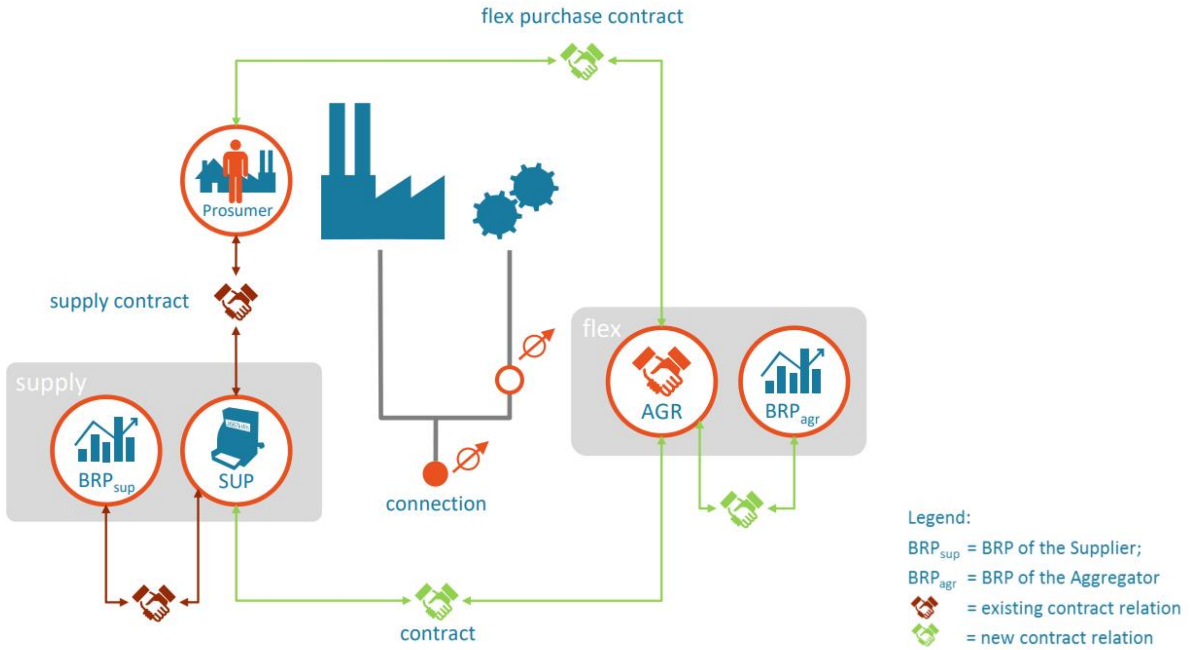
[72] "Recommended practices for DR market design - Universal Smart ...." https://www.usef.energy/app/uploads/2017/09/Recommended-practices-for-DR-market-design-2.pdf. Accessed 5 Sep. 2018.



In this situation Aggregators create imbalance but this is ‘uncorrected’ - suppliers must either source enough BMUs to compensate or risk being fined.

One alternative would be for the Aggregator to have some sort of contractual relationship with the supplier where they assume responsibility for the imbalance caused by flexibility so that the impact of this on the open supplier position can be taken into account. The volume could also be traded through this. This second possibility is depicted below:

In the UK market Aggregators could also take responsibility for the imbalance themselves by either directly participating in the balancing mechanism (through new BM Lite arrangements or otherwise) or contracting with a party with access to the balancing mechanism (either a second supplier or other). This is depicted below:



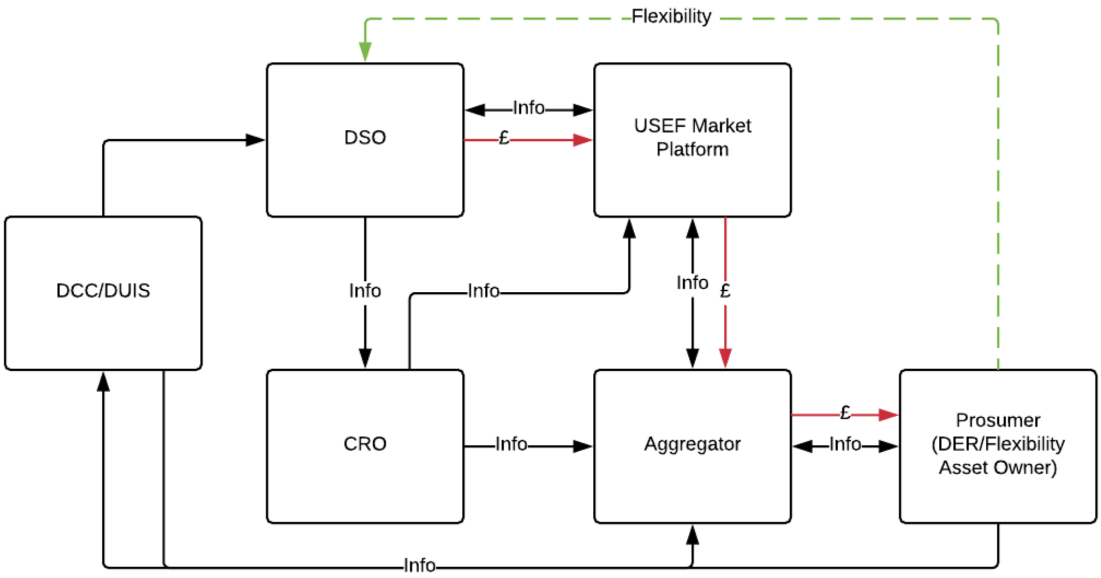
All configurations are possible but the most likely initially would be the 'uncorrected' implementation (particularly in local flexibility markets). Volume and balancing costs could still be taken into account passively by the Aggregator in this situation through the normal settlement of prosumer consumption (e.g. a dynamic time of use tariff).

In the following use cases we describe the operation of a local flexibility market with the 'uncorrected' Aggregator implementation. This reflects current arrangements and simplifies the initial market model. This could be extended at a later date.

4.3.2. High Level Use Cases

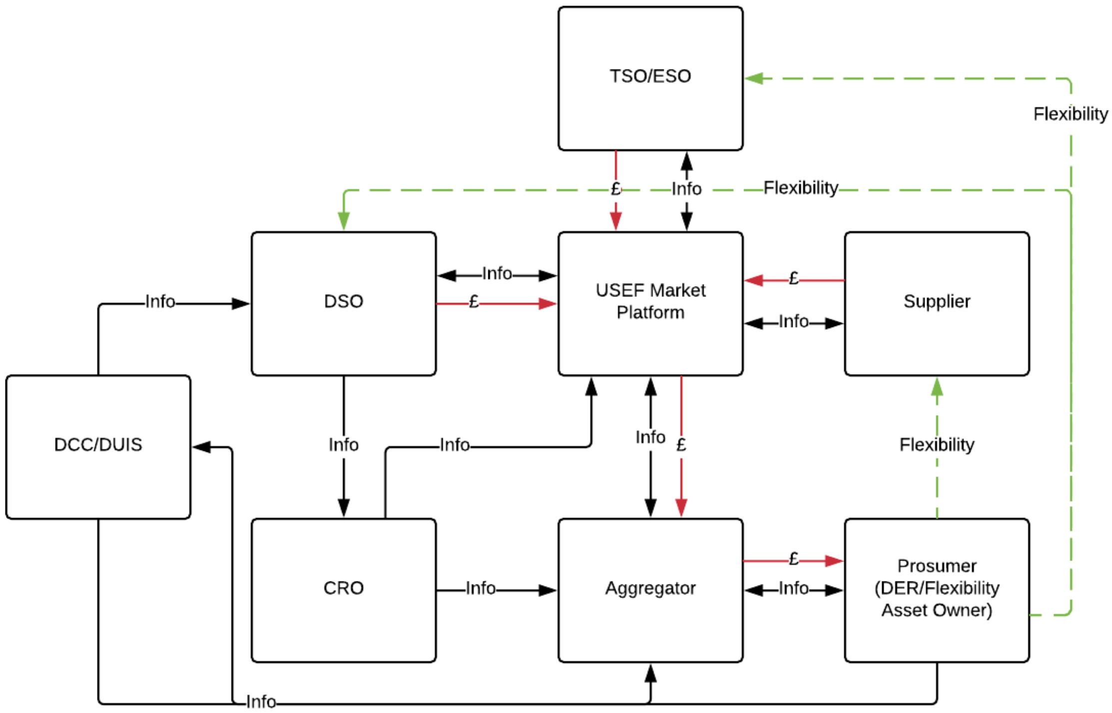
Two High Level Use Cases are presented below. The first is for an initial demonstrator and the second shows a commercial system with extensions for interacting with national flexibility markets.

3.10.1.2 HLUC 1: DSO Transition Local Flexibility Market



Objective	Procure flexibility for peak load reduction and capacity management using long term contracts
Actors	Prosumer, Aggregator,DSO,CRO, Market Platform Operator
Use Case Steps	1. USEF MCM 2. Audit/compliance (may fall within MCM)
Preconditions, assumptions, post conditions	● CRO maybe part of DSO. ● This doesn't reflect all payments/information exchange, only those relating to flexibility market (for example, network charges to DSO are not included).

3.10.1.3 HLUC 2: DSO local flexibility market extension to national flexibility market



Objective	In addition to HLUC 1, flexibility is procured by other actors for purposes such as secondary/tertiary system control and portfolio optimisation. An established local flexibility market is extended to provide flexibility to other actors. The system may be marketised with prices for each unit of flexibility.
Actors	Prosumer, Aggregator,DSO(s),ESO,Supplier(s),CRO,Market Platform Operator
Use Case Steps	1. USEF MCM. 2. Audit/compliance (may fall within MCM).
Preconditions, assumptions, post conditions	● CRO maybe part of DSO. ● Aggregator implementation is uncorrected - otherwise there maybe payment/info exchanged between Aggregator and supplier. ● This doesn't reflect all payments/information exchange, only those relating to flexibility market (for example, network charges to DSO are not included).

4.3.3. SGAM outline

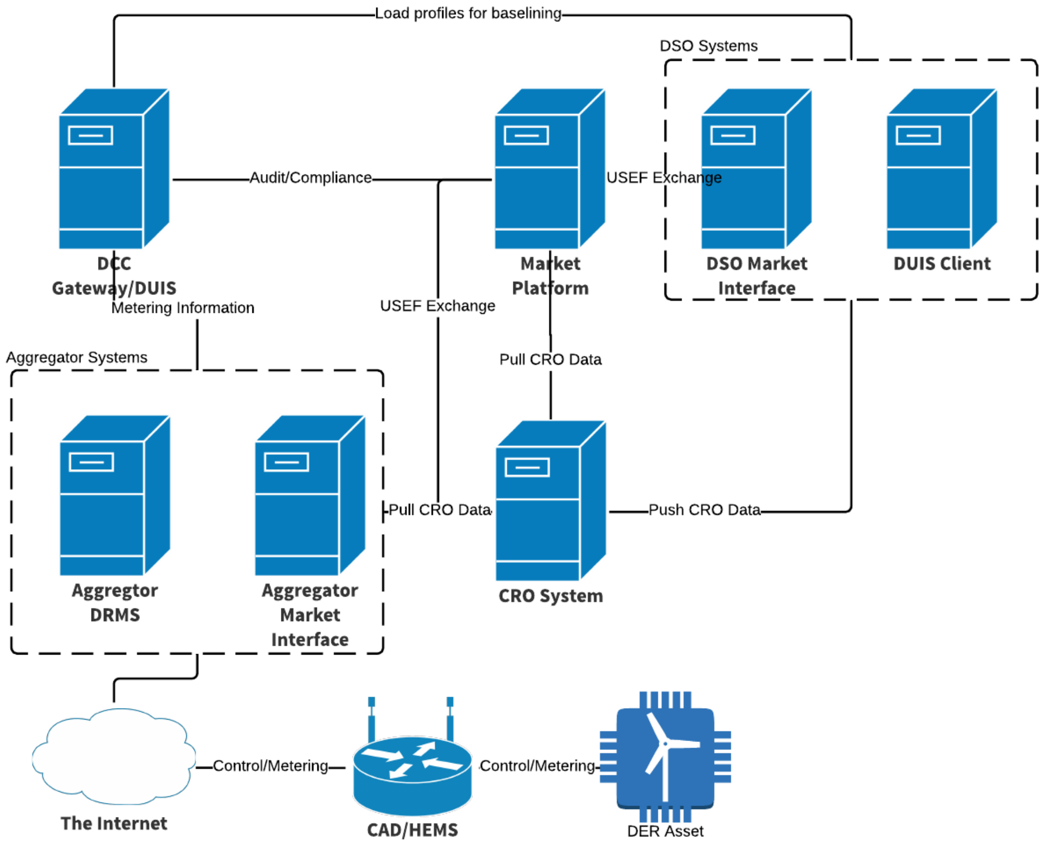
A local flexibility market such as ECAS will span multiple SGAM domains, zones, and interoperability layers.

Layer	Example of ECAS functions in this layer
Component Layer	These include the definition of different actors such as the Aggregator, Community Energy Service Company, Prosumer, Market Platform Provider, DSO, and ESO as well as their systems and associated devices, such as the Aggregator backend, market platform,
Communication Layer	ECAS uses primarily IP-based communication.
Information Layer	ECAS uses information structures specified in the SMETS (DLMS/COSEM for metering), OpenADR (for control, market information, sub-metering), and USEF (market information) specifications as well as custom formats.
Function Layer	High level use cases (such as described below).
Business Layer	Business models e.g. ECAS business model involving federation of community energy groups.

4.3.4. ECAS Technical Description

In this section we outline some of the key technical systems which distinguish ECAS. Other systems will be required, however where their operation is already defined (or implicit) in the USEF framework description they are not specified in detail.

3.10.1.4 High Level Architecture



4.3.4.1. CAD/HEMS

Central to the delivery of ECAS will be the use of a Home Energy Management System (HEMS) in the home to interface with flexibility assets. The functionality of this will be combined with a Consumer Access Device (CAD) which will pair into the smart meter home area network (HAN) thus providing a unified source of information about energy demand/generation and flexibility assets and a means of control for those assets which will be connected to the Aggregator DRMS system.

The way that CADs interact with smart metering system has not been fully determined at the current time, although it is already technically possible to undertake the required pairing procedure to connect CADs to the smart meter HANs on customer premises. Currently (with SMETS1 based metering systems) there is a reliance on suppliers and their meter equipment/operators to support this procedure, however SMETS2 metering equipment (and SMETS1 equipment which has been migrated to the DCC - a process which should begin at the end of 2018) can be provisioned by other DCC users (which maybe device manufacturers, system integrators, or Aggregators who have gone through the required DCC user entry process). This process of pairing devices will need to be streamlined to reduce costs and if large numbers of CAD devices are to be paired into HANs on consumer premises.

Some indicative explicit costs for this part of the system are presented below. These are based on quotes received from manufacturers and operational costs from similar existing systems. All costs are for a small scale demonstrator involving 100 - 500 participants.

Item	Cost
CAD/HEMS device	£50 per device (one-off)
Device management	£1 per device per year

4.3.4.2. Aggregator Demand Response Management System (DRMS)

The Aggregator demand response management system (DRMS) contains the business logic for the registration, commissioning, monitoring, management, and dispatch of flexibility assets (via the HEMS) and also communicates with the interfaces, and responds to requests from other business systems and customer applications.

An off-the-shelf USEF-compliant DRMS does not currently exist, but there are a large number of DRMS systems which could be developed to meet the requirements of USEF. We believe the development of OpenADR-based DRMS systems, which are made by a variety of vendors, as well as being available open source, is a viable route forward.

It is more difficult to estimate the development costs associated with such a system. Even an off-the-shelf or a vendor system will require integration with other business systems (e.g. CRM/billing).

4.3.4.3. Aggregator-DCC interface

The Aggregator DCC interface is required to validate and verify the actions taken to control flexibility assets and ensure that a unified view of settled electricity consumption/generation is accessible to all actors. The interface requires a DCC Gateway Connection and for the Aggregator to become a party to the SEC and a DCC User. This facility could also be used to pair the CAD/HEMS devices on behalf of users (and potentially also any Auxiliary Load Controllers) as a core business function of the Aggregator.

We present some indicative costs below.

Item	Cost
DCC Gateway Connection (Initial)	£400
DCC Gateway Connection (Ongoing)	£600 per year
Development of DUIS interface application	£30,000
Testing of DUIS interface application	£5000

4.3.4.4. Common Reference

The most important role of the system and actor providing the common reference is to map MPANs to USEF ‘congestion points’ based on a shared logical/graph representation of the distribution grid. In principle there are two operations associated with this, one is given an MPAN to determine which congestion points it is associated with; the other is given a congestion point to determine the MPANs associated with it. This functionality overlaps with that currently provided by the meter asset registry and this could be extended to include this information. Alternatively, given that the high degree of information sharing required with the DSO, it may make more sense for it to be operated by them or an associated independent organisation. This would be a reasonable application for blockchain technology as it is required to provide a single shared source of verifiable information for multiple actors (although it would likely need to be of the more restricted 'permissioned' and 'private' variety due to the sensitive nature of the MPAN information). We are seeing this role being played by market platforms currently like Piclo Flex, which connects DNOs requirements with flexibility providers. However, this information is valuable to the good operation of a marketplace for flexibility and should therefore not be monopolised by DSOs or single providers.

4.3.4.5. Market Platform

A market platform is seen as a key component of local energy and flexibility markets although its role is not explicit in the USEF framework. In a USEF context it can be seen as providing the compliant interfaces for different actors, hosting the market operation, and providing transparency/visibility to market information and operations, audit/compliance, and settlement of accounts. Based on this description it seems logical (and consistent with how the UK market currently operates) for this to be operated by an independent neutral party.

4.3.5. Analysis of ECAS

- Based on the above described use cases, it can be seen that the operation of local flexibility markets relies on a much higher level of information exchange than is currently the case. This underlines the need for standards in information models and interfaces supporting interoperability to manage the higher level of complexity.
- ECAS assumes Aggregators will have a high level of access to the UK smart metering system as (currently) non-licensed third parties under the 'Other User' role. This does not seem inconsistent with the Smart Energy Code however it does not represent an oft-discussed use case of the system (third-party access has mainly been discussed in relation to comparison services which only require occasional access). It maybe that an Aggregator user role should be added to the SEC/DCC definition. This may parallel efforts to license the operation of Aggregators.
- There is also a requirement to grant systematic access to large numbers of CADs to the Home Area Networks within the UK smart metering system. Whilst this is technically possible it may present certain operational and risk management issues.
- There is a specific requirement in ECAS for a common reference operator (CRO) role. Currently DSOs have total control over information taken from substations and other parts of their network and there is currently no shared belief or understanding that this information needs to be made accessible to meet the information requirements of future markets and smart grid systems.
- As discussed in a previous section, the activity of the Aggregator is 'uncorrected' i.e. it is not required to be reflected in settlement. This is not a desirable state of affairs as the impact on system imbalance falls unduly on the supplier as the balance responsible party. In other European countries Aggregators are responsible for imbalance and required to appoint a BRP.
- Certain actors do not have much of an incentive to adopt a standards based approach. Supply chain actors may attempt to monopolise the provision of ADS systems by promoting their own standards.

4.4. Conclusions and Recommendations

This report has reviewed the application of several technical standards and frameworks to the development of local flexibility markets in a UK context and proposed a concept local flexibility market 'ECAS' which implements these standards.

Based on the initial technical assessment of the system above we have concluded that an ECAS-style system is technically feasible (we make no comment on the business case for ECAS here) and could even be assembled by adapting existing products and services.

An analysis of the concept has highlighted some potential barriers to the implementation of such a system, and we base a set of recommendations on this:

- The role of Consumer Access Devices and their intended use cases within the UK smart metering system needs to be clarified by BEIS, Ofgem, and within the Smart Energy Code. These devices are essential in providing the "real time" data which is claimed to be one of the main products of the system and which are essential to the operation of the future smart grid and flexibility markets.
- Access to the DCC by an Aggregator may fall outside originally intended use cases even if it is technically permitted. There maybe a case to define an Aggregator user role within the SEC (which could also permit access to different functions than are currently available to the 'Other' user role).
- Whatever local flexibility market model maybe adopted, the historical and current operational status of distribution networks will be an essential tool to support planning and provision of flexibility and access to this information should be guaranteed, potentially by a neutral third-party performing the 'Common Reference Operator' role described in USEF (as well as any other functions required in the UK context). This role could be played by existing UK market actors such as the DCC or Elexon.
- There needs to be more recognition of the whole system impact of the activities of Aggregators, specifically how imbalance created by their activities should be taken into account. This has not been as important where Aggregators have provided services to support the ESO and therefore it is assumed their activities are benefit balancing, but where flexibility is provided to other actors this is not generally the case. This may need to be an area of focus in regulating Aggregators, potentially introducing a requirement to take responsibility for imbalance through the balancing mechanism (or otherwise) directly or by appointing a third party. Ofgem have indicated[73] that this is the direction of travel and P354 BSC modification proposal[74] will, when implemented, mean Suppliers are not penalised for imbalance caused by flexibility instructed by the ESO.
- With access to the balancing mechanism being granted to non-licensed parties and discussions around more access to wholesale markets there is an increasing case to review the supplier hub model. Separating the BRP and retail functions of suppliers (as is currently done in some EU markets) could promote further competition in both electricity supply and help stimulate domestic Aggregator activity.

[73] "Ofgem's views on the design of arrangements to accommodate ...." 24 Jul. 2017, https://www.ofgem.gov.uk/system/files/docs/2017/07/ofgem_s_views_on_the_design_of_arrangements_to_accomodate_independent_Aggregators_in_energy_markets.pdf. Accessed 12 Sep. 2018.

[74] "P354 - ELEXON." https://www.elexon.co.uk/mod-proposal/p354/. Accessed 12 Sep. 2018.

Future work on USEF and local flexibility markets is already underway. Both USEF and SGAM will be further examined as part of SP Energy Networks FUSION project[75] with a USEF demonstrator planned for 2020. This will involve further scrutiny of USEF and its applicability to the UK context as well as the development of USEF compatible systems able to test its feasibility.

[75] "Fusion - SP Energy Networks." https://www.spenergynetworks.co.uk/pages/fusion.aspx. Accessed 11 Sep. 2018.

5 WP5: Policy, Regulatory and Legal Considerations

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5.1 Related primary legislation

The need to decarbonise the UK's energy system is mandated by the Climate Change Act of 2008, which sets a statutory long-term target to reduce greenhouse gas emissions to 80% lower than 1990 levels, by the year 2050[76]. The purpose of the Act is to provide a clear legal framework for a long-term direction of travel in policy around economy-wide decarbonisation, with five-year carbon budgets[77], while also establishing the Committee on Climate Change (CCC) to ensure emissions targets are evidence-based and can be independently assessed[78]. The CCC has recommended to the Government that it should aim to reduce the carbon intensity of power generation from 350 gCO_2/kWh currently to 100 gCO_2/kWh by 2030. This mandate for decarbonisation of the energy system requires a greater share of renewable energy generation and supplementary low carbon technology to contribute to the UK's energy mix, especially if the UK is to meet its statutory fourth and fifth carbon budgets set under the Climate Change Act for the early 2020s and early 2030s[79].

The BEIS Clean Growth Strategy[80] was the Government's response to sections of the Climate Change Act. This strategy set out policies and proposals to deliver 'clean growth' (effectively increased economic growth coupled with decreased emissions[81]), with one of the key policy areas needed to meet the fifth carbon budget to deliver 'clean smart flexible power', with power accounting for 21% of UK emissions. Included was a proposal to invest £265 million in smart systems to reduce the cost of electricity storage, and to develop demand response technologies to help balance the grid[82]. This policy directive has been followed up in greater detail in BEIS and Ofgem's Smart Systems and Flexibility Plan[83].

This UK policy backdrop means that much more renewable energy generation needs to be added to the electricity network, simultaneously with the electrification of heat and transport, over the next decade to meet the UK's emissions targets. Due to the inherent intermittent nature of renewable energy generation, more flexibility with greater capability to balance the electricity network will be required to smooth out peaks in demand and generation and make the energy system operate more efficiently.

Poyry and Imperial College's report to the CCC estimated the required amount for additional capacity of flexible technology needed to meet 2030 carbon intensity targets[84] ranged from 3-15 GW. Storage, DSR, interconnectors and flexible generation will collectively enable more renewable generation to be added to the network, whilst either avoiding or deferring expensive network infrastructure upgrades.

Trajectories for EV, heat pumps and other disruptive sources of electricity demand will likely have a material effect on the amount of flexibility that is required in the future. National Grid's Future Energy

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[76] https://www.legislation.gov.uk/ukpga/2008/27/pdfs/ukpga_20080027_en.pdf
[77] http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2018/04/10-years-of-UK-Climate-Change-Act-Summary-Policy-Brief.pdf
[78] https://www.theccc.org.uk/tackling-climate-change/the-legal-landscape/the-climate-change-act/
[79] http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2018/04/10-years-of-UK-Climate-Change-Act-Summary-Policy-Brief.pdf
[80] https://www.gov.uk/government/publications/clean-growth-strategy
[81] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf
[82] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf
[83] https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf
[84] https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf

Scenarios (FES)[85] analysis shows a wider range of outcomes for electricity generation, demand, storage as well as gas supply and fuel mix in the UK.

Table 11: Levels of additional flexibility-providing capacity required for 2030 carbon intensity targets
Source: Roadmap for Flexibility Services to 2030, Poyry and Imperial College London, May 2017

Flexible technology	By 2020 (GW)			By 2025 (GW)			By 2030 (GW)		
	Low	Central	High	Low	Central	High	Low	Central	High
New flexible generation	1	3	5	2	6	10	3	9	15
Storage	0.8	2.9	5	3.2	11.6	20	5.6	20.3	35
DSR	2.1	6.3	10.5	2.76	8.28	13.8	3.42	10.26	17.1
Interconnection	3.4	3.4	3.4	4.45	5.825	7.2	5.5	8.25	11

5.1.1 Considerations for domestic and community flexibility

A significant amount of flexibility needs to be added to the energy system and the flexibility potential from existing sources/assets must be exploited, to enable further decarbonisation progress to meet our legislative objectives. Research suggests that integrating new sources of flexibility will provide annual system-wide benefits equal to £3.2-£4.7 billion for an emissions target of 100 gCO_2/kWh in 2030[86]. This makes the case for stringent policy to support the growth, enabling markets and routes to those markets for flexibility at all scales. The potential scale of domestic and community flexibility is unknown, but almost certainty likely to rapidly increase moving forward. Models such as ECAS could potentially act as a link between smaller entrants into network flexibility markets with the right policies and regulatory supporting framework. A firmer and more rapid approach to rolling out smart meters, home batteries, smart appliances and controlling software could unlock this untapped source of flexibility, by allowing greater aggregation of distributed resources, helped by the potential increased uptake of EVs, increasing more readily accessible flexible loads at the domestic level.

5.1.2 Enabling factors

Some of the enabling factors to overcoming key barriers and improving access to flexibility[87] include:

- Increased consumer engagement around energy use and energy behaviour
- Increased uptake of second generation smart meters
- Increased deployment of domestic energy storage
- Increased deployment of EVs with smart home charging/control infrastructure
- Accessible domestic demand-side energy management services and systems

For effective domestic demand-side energy management to work, an engaged customer base, coupled with tangible flexible technologies and policy driven smart metering provision, is essential.

Local energy stakeholders, such as community energy groups[88], could potentially have a key role to play in engaging and coordinating flexibility at a more regional/localised level. Engaging individuals through

[85] https://www.legislation.gov.uk/ukpga/2008/
27/pdfs/ukpga_20080027_en.pdf
[86] http://www.lse.ac.uk/GranthamInstitute/wp-content/uploads/2018/04/10-years-of-UK-Climate-Change-Act-Summary-Policy-Brief.pdf
[86] https://www.theccc.org.uk/tackling-climate-change/the-legal-landscape/the-climate-change-act/
[86] http://www.lse.ac.uk/Grantha
mInstitute/wp-content/uploads/2018/04/10-years-of-UK-Climate-Change-Act-Summary-Policy-Brief.pdf
[87] https://www.gov.uk/government/publications/clean-growth-strategy
[87] https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf

their supplier is one method but being approached by a local agent such as a community energy group (as a more trusted intermediary), could potentially be more fruitful.

5.2 Wider policy considerations for local flexibility

5.2.1 Smart Systems and Flexibility Plan - considerations

BEIS, together with Ofgem, set out a number of policy and regulatory actions in the Smart Systems and Flexibility Plan, part of the Clean Growth Strategy[89]. Together with the ENA and DNOs, the plan aims to upgrade the UK's regulatory and market framework and aid the transition to a smarter, more flexible energy system by:

- Removing the barriers to smart technologies such as DSR and storage
- Enabling smart homes and businesses
- Improving the access to energy markets for new technologies and business models

Outlined in the plan are some key policy directives around storage, specifically around licensing, planning, connections and charging (such as use of system charges etc.). The plan itself is supplemented by an Action Tracker detailing outputs, progress and organisations that are taking the lead on each area. Some of the actions from the plan are directly relevant for the feasibility of domestic scale flexibility aggregation. See examples in Table 12:

Table 12: Smart System and Flexibility Action Tracker - key points relating to domestic flexibility aggregation

Action	Relevance, Progress and Future Consideration
The flexibility markets feasibility study competition (that this research falls under) Domestic DSR innovation competition	Seeing innovation funded research to explore business models, as well as tangible control assets in the home. Outcomes of these innovation funded trials and research projects may be vital in understanding why domestic flexibility won't work now but may do in the future under more developed scenarios.
Changes to storage regulation that demonstrates how storage benefits the network and wider energy system	Adjustments to network charging was a positive change for storage projects. However classifying storage as a subset of generation is considered to be a short-term position, whilst storage seeks to have its own classification and/or licence.
Planning and location frameworks to enable storage to be located on the same site as renewable generation	Ofgem has recently released guidance on the co-location of storage with FIT or RO accredited generation[90]. BEIS are continuing to explore the issue of how storage is to be treated in regard to planning. This may become a technology specific consideration, with the site footprint and site-specific variation between solid state battery storage, pumped hydro and liquid air storage technologies, for example.
Smart metering rollout programme	Placing the obligation to install smart meters on electricity suppliers and BEIS having a role in reporting on progress, Ofgem monitoring and incentivising suppliers to achieve their targets (and penalising those who do not).

[88] https://assets.publishing.service.gov.uk/gove rnment/uploads/system/uploads/attachment_data/file/700496/clean-growth-strategy-correction-april-2018.pdf
[89] https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf
ems_and_flexibility_plan.pdf
[90] See Ofgem guidance (June 2018): https://www.ofgem.gov.uk/publications-and-updates/guidance-generators-co-location-electricity-storage-facilities-renewable-generation-supported-under-renewables-obligation-or-feed-tariff-schemes-version-1

Enabling Aggregators to access the Balancing Mechanism	This has effectively come to fruition, with LimeJump announcing[91] its entry into the BM.
Network access reform – Ofgem will look into changing the existing structure of network charging costs to reflect real benefits to the system as part of its Targeted Charging Review[92]	A lot of work has been undertaken by Ofgem to review the way consumers (and generators) are charged to connect to, use and pay towards the upkeep of the electricity network. Commencing with the Targeted Charge Review in early 2017, where Ofgem set up the Charging Futures Forum. More recently, Ofgem has consulted on specific charging areas of access and forward-looking charges[93]. This consultation proposed a number of changes under the following arrangements: i) Shallow connection charges for distributed generation (DG), effectively proposing to echo the connection charging arrangement on the transmission network, by not requiring DG to have to pay for all the upstream network reinforcement related to their project connecting, as is currently the arrangement. ii) A tougher set of use of system charges for generators, seeing DG contributing towards transmission network use of system charges and potentially an increase in equivalent regional charges on the distribution network. iii) The current transmission network demand peak penalty mechanism (Triad charges) may be removed, thus changing the business case for behind the meter storage and industrial energy management strategies. iv) EV related charging tariffs, smart or managed 'at home' EV charging arrangements

Many of these reforms are seeking to encourage 'smart and flexible' technologies to connect and add value to the network. The potential for these policy and regulatory actions to level the playing field and make it easier for small-scale generation and storage to connect to the network is still to be seen.

In terms of some of the specific policy enablers we identified in section 5.1.2, some additional detail around progress in some of these areas is outlined in the sections that follow, namely:

- Smart meter rollout progress
- Faraday Battery Challenge
- EV uptake trajectories
- Smart appliances

[91] See LimeJump press release, Aug 2018: http://www.limejump.com/limejump-enters-balancing-market/
[92] https://www.ofgem.gov.uk/publications-and-updates/targeted-charging-review-consultation
[93] See Ofgem consultation, July 2018: https://www.ofgem.gov.uk/system/files/docs/2018/07/network_access_consultation_july_2018_-_final.pdf

5.2.2 Smart Meter Rollout progress

The smart meter rollout is a key part of the Smart Systems and Flexibility Plan, with domestic smart metering being a vital component of enabling and aggregating domestic households in local flexibility markets. As of March 2018, 12.3 million smart and advanced meters have been installed in total and just over 11 million of these are now in operation in homes and businesses across Great Britain[94]. See breakdown in Table 13. The Government's Smart Metering Programme aims to ensure every home and business is offered a smart meter by the end of 2020, rolling out over 50 million meters to approximately 30 million premises; all domestic properties and smaller non-domestic sites.

Table 13: UK Smart meter rollout progress (source: BEIS Smart Meters Quarterly Report, to end of March 2018)

Meter Type	Installed & Operating as of end of March 2018 (millions)		
	Domestic	Non-domestic	All Meters
Smart Meters	10.02	0.06	10.06
Advanced Meters	-	1.00	1.00
Total	**10.02**	**1.05**	**11.06**

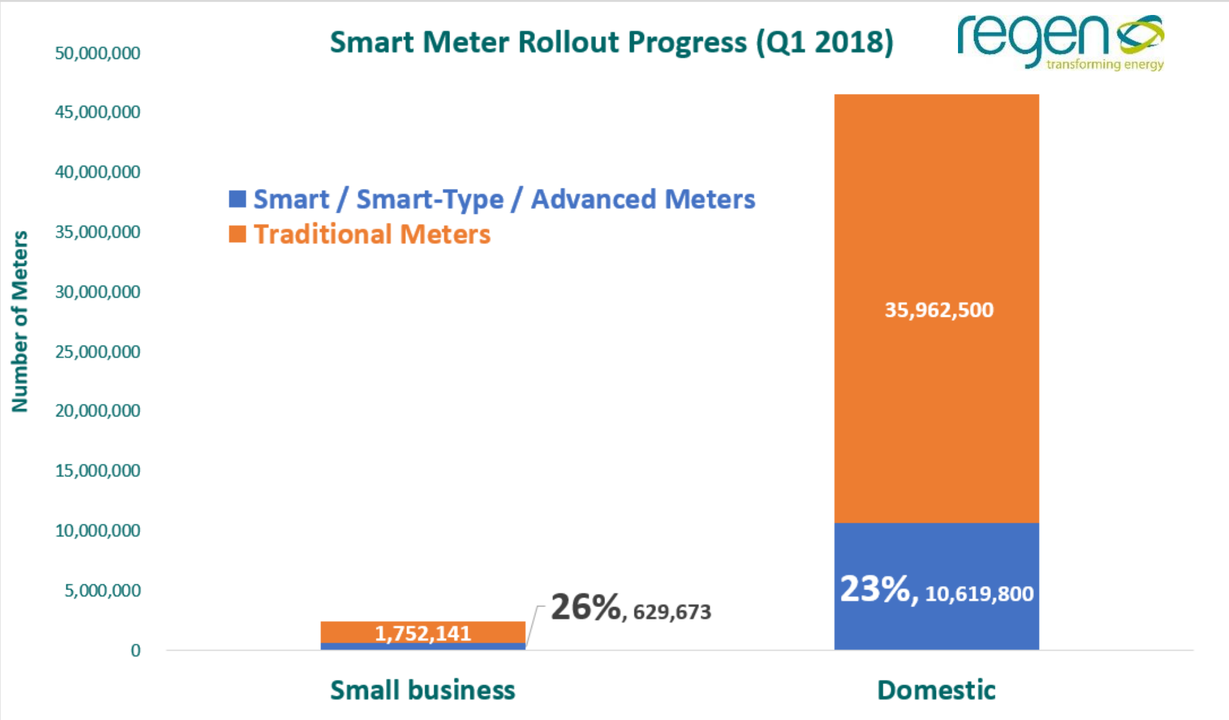
The Smart Metering Programme is being delivered in two phases:

- The foundation stage starting in 2011, developed the commercial and regulatory frameworks to support smart metering through engagement with the energy industry, consumer groups and other stakeholders, learning lessons from early installations and trial systems
- The main installation stage began in November 2016 and goes through to the end of 2020. The aim is for most households and small businesses to have smart meters installed by their supplier and that national smart meter data and communications infrastructure will be fully functioning.

Unfortunately, as it stands, the main installation stage is some way off meeting its 2020 target, as can be seen in the relatively low percentage of overall premises, that the above smart meter installations represent. See Figure 28.

[94] See BEIS Smart Meters Quarterly Report to End of March 2018: https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/712151/2018_Q1_Smart_Meters_Report_.pdf

Figure 28: Smart Meter Rollout Progress to end of March 2018 (Source: BEIS, Analysis: Regen)



The smart meter rollout is currently poor, as energy suppliers fall notably behind their required installation government targets[95]. There are recent examples of some suppliers missing their obligated targets, with EDF being fined £350,000 by Ofgem in June 2018[96] for missing its 2017 smart meter target and Npower being fined £2.4 million in August 2018[97] for falling short of their non-domestic advanced meter target.

Other than purely the low number of installations, a further issue arises from the lack of interoperability of first generation smart meters as their data and communication systems vary from supplier to supplier. To resolve this issue the government is consulting on proposals to require energy suppliers to bring first generation smart meters under the national Data Communications Company, or failing that, mandate suppliers to replace first generation smart meters with second generation models which operate a universal communication system. BEIS issued a consultation on proposals regarding smart appliances and interaction with smart meters, which is covered in more detail later in this report.

5.2.3 Faraday Battery Challenge

The launch of the Faraday Battery Challenge, as part of the Industrial Strategy Challenge Fund[98], sees some £246 million of funding available to support the development of new battery technologies. This is partly focussed on the preparation for the electrification of transport but is also an opportunity to improve the effectiveness of static battery storage at varying levels. The fund aims to connect university research to businesses and to increase R&D more generally, with an aim to take the latest technologies closer to market and commercial feasibility[99]. The end goal of the Faraday Challenge is to develop

95 https://www.current-news.co.uk/news/smart-meter-roll-out-offering-all-the-signs-of-a-car-crash-agree-mps
96 See Ofgem press release, June 2018: https://www.ofgem.gov.uk/publications-and-updates/edf-energy-pays-350000-after-missing-smart-meter-targets
97 See Ofgem press release, August 2018: https://www.ofgem.gov.uk/publications-and-updates/ofgem-fines-npower-24-million-failing-meet-advanced-meter-deadline
98 https://www.gov.uk/government/collections/industrial-strategy-challenge-fund-joint-research-and-innovation
99 https://www.gov.uk/government/collections/faraday-battery-challenge-industrial-strategy-challenge-fund

batteries that are cheaper and more cost-effective, more durable and last longer, safer and lighter, and recyclable at the end of their life.

It is hoped that in making better batteries more widely available, the cost of EVs, home batteries and large storage plants will come down, as well as making assets more practical and more attractive to customers, reducing emissions and using storage to manage intermittency. Low-cost, high-performance batteries would also make domestic battery storage more widespread, increasing the amount of one of the more readily dispatchable flexible loads at the household level.

Related to the launch of this fund, was the creation of the UK's first independent institute for electrochemical energy storage technology – the [Faraday Institution](). This institute aims to drive research, training and analysis of (predominantly) electrochemical battery technology. See Figure 29.

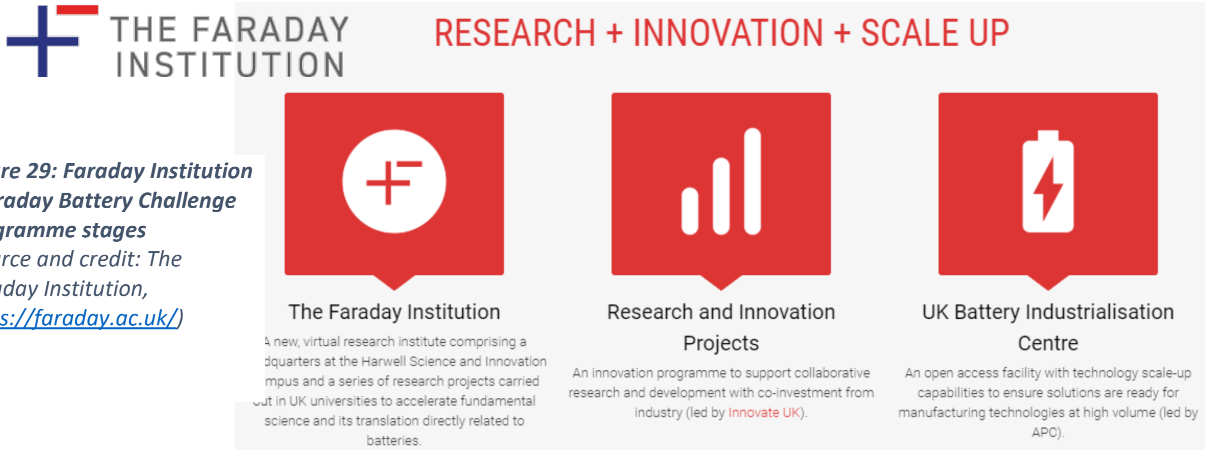
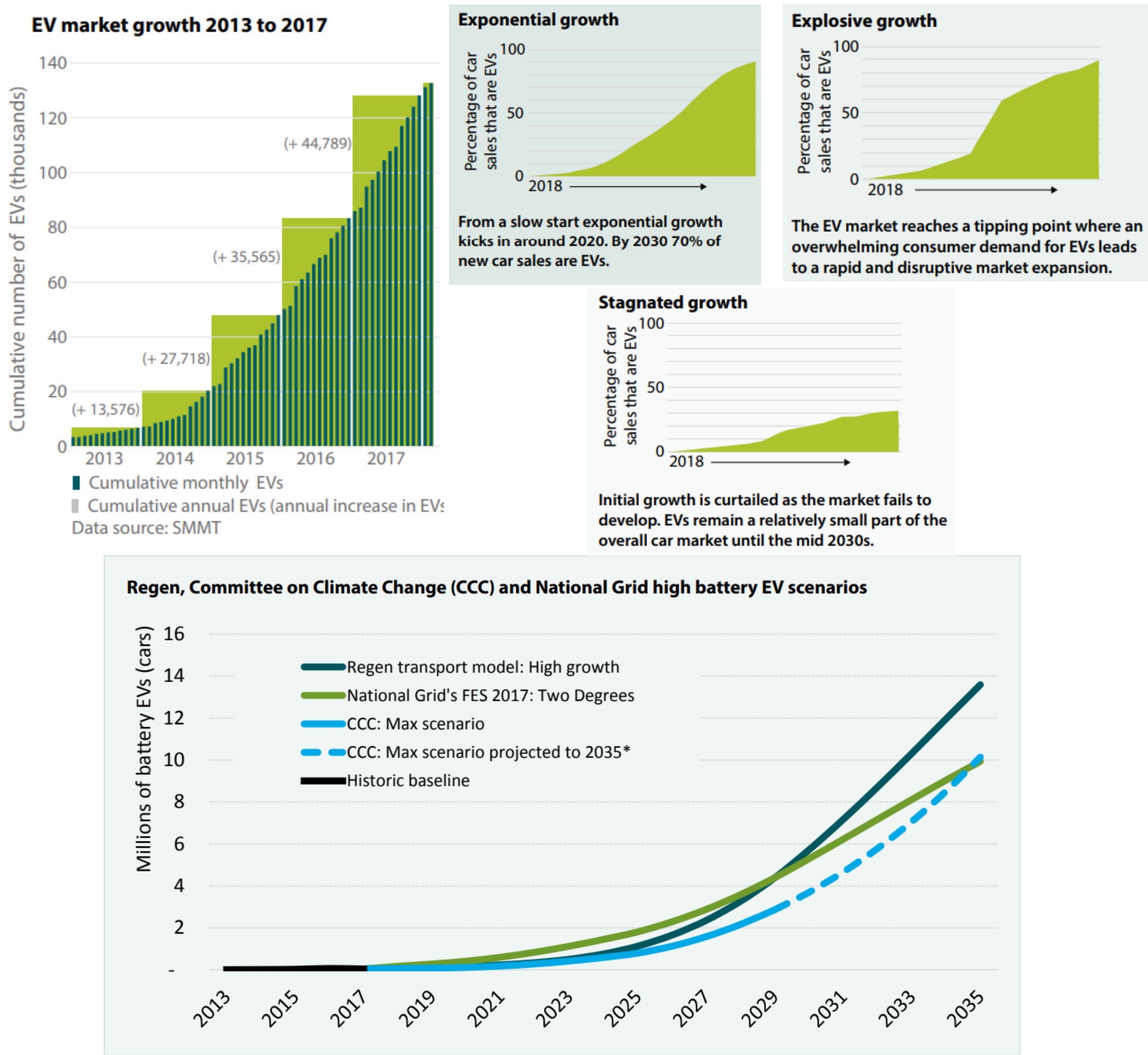


Figure 29: Faraday Institution - Faraday Battery Challenge programme stages
(Source and credit: The Faraday Institution, [https://faraday.ac.uk/]())

5.2.4 EV uptake projections

Regen's analysis in April 2018[100] showed that EV uptake could take a number of different trajectories. Building on the 2017 baseline position of c.120,000 (see Figure 30), the number of EVs on the road could vary significantly out to 2035. But Regen, National Grid, Committee on Climate Change and many other industry organisations are aligned that EVs will be into the millions within the 2030s (see Figure 30).

Figure 30: Regen baseline and growth analysis for EVs, source: [Harnessing the Electric Vehicle Revolution](), Regen



The nature of charging EVs at home is also an evolving area, with smart charging control systems, managed charging arrangements being proposed by DNOs[101] and electricity tariffs aimed to shift EV

[100] See Regen market insight paper, 'Harnessing The Electric Vehicle Revolution', April 2018: https://www.regen.co.uk/wp-content/uploads/Harnessing_the_electric_vehicle_revolution_-_Regen_market_insight_series_-FINAL_2_pages-3.pdf

[101] See SSEN consultation on managed EV charging, March 2018: http://news.ssen.co.uk/news/all-articles/2018/march/smart-ev/

charging out of times of peak demand[102]. The potential for EV owners to flex their import/export power from their EV is potentially uncertain and the role EVs can play in local flexibility markets is potentially significant, but unclear.

5.2.5 Smart Appliances consultation

In March 2018, BEIS launched a consultation on introducing primary legislation to set standards for smart appliances[103]. Government wants to introduce legislation to ensure minimal functional standards, stimulate investment in product development, and make the UK a pioneer in the emerging sector with regulation that can help overcome market failure, manage risks and align with international standards. The standards proposed in the consultation follow these principles:

- **Interoperability**: so that all devices can understand the same language and communicate with multiple interfaces
- **Grid stability**: to ensure there are no sudden unexpected drops in demand or unintended shifting of peak demand
- **Cyber security**: for all devices to have minimal access points, with secure control systems that are regularly penetration tested
- **Data privacy**: covered by the Data Protection Act 2018[104], consumers to have the choice over who their data gets shared with

BEIS is pursuing primary powers to regulate these standards for UK smart appliances, with the consultation seeking views on:

- Whether BEIS having regulatory powers is appropriate,
- Whether the proposed labelling of appliances is the best method to communicate standards,
- Whether the need to mandate that all appliances are/should eventually be smart,
- BEIS' impact assessment,
- Whether proposed functionality is appropriate,
- Other areas around consumer protection.

It is largely accepted that regulatory frameworks around consumer protection and data protection are needed for widespread consumer acceptance[105]. Therefore, an ECAS model might stand to benefit from an increased uptake of smart appliances with universal data and interoperability standards, brought about if the regulation proposed in the consultation document is agreed and enacted. In short, if smart appliances are mandated to be, standardised and sold with the protection of consumers and consumers' data at its core, it is likely that there could be a surge in smart appliances that flexibility aggregation platforms might seek to access and control.

It is advised that Aggregators should look to be involved in future processes developing updated standards, so as to have their voice heard and ensure regulation is not introduced which harms their business model or prevents flexibility service type operability. One danger identified, which has the potential to hinder the development of a functioning local flexibility market, is that mandatory standards could drive prices of appliances up, deterring early adopters, meaning less load is available for aggregation at the domestic level.

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[102] Octopus launched the first time of use tariff tailored to EV owners, see Zap Map article, June 2018: https://www.zap-map.com/octopus-energy-launches-ev-driver-tailored-tariff/

[103] See BEIS Consultation on Proposals regarding Smart Appliances, March 2018: https://www.gov.uk/government/consultations/proposals-regarding-setting-standards-for-smart-appliances

[104] See Data Protection Act 2018: http://www.legislation.gov.uk/ukpga/2018/12/contents/enacted

[105] Referenced by Committee on Climate Change: https://www.theccc.org.uk/wp-content/uploads/2017/06/Roadmap-for-flexibility-services-to-2030-Poyry-and-Imperial-College-London.pdf

A more fundamental consideration is that regardless of how well regulated, standardised and comms-enabled smart appliances may become, it does not negate the fact that the potential for appliances to provide real energy flexibility benefits to the system is low. Appliances in themselves are becoming more energy efficient, either from using less instantaneous power (fridges, cookers) or run-times (washing machine/dishwasher cycles), thus the amount of demand reduction is likely to be relatively small. In addition, the alignment of dispatching flexibility at a time when appliances are not being used, coupled with the likely need to set baselines using sampling periods, will mean that the availability of smart appliances to provide useful response to flexibility markets (local or national) is again low.

5.2.6 Key policy considerations and conclusions for the ECAS model

The Smart Systems and Flexibility Plan lays out the Government's vision and provides a roadmap to a future smart and flexible energy system, complete with markets in which an ECAS could operate. Removing barriers to smart technologies, enabling smart homes and businesses and improving access to energy markets for new business models and technologies are all hugely promising for the development of an ECAS. However, to ensure that smaller loads can participate in local flexibility markets in the near term, innovation trials and feasibility studies such as this one must continue, with key learnings taken forward, to ensure that the technology and business models can be replicated and scaled up. The outcome of the domestic DSR trials should look to focus on responding to 'real' system flexibility needs, as well as exploring non-system flexibility, such as co-operating demand or generation with storage/DSR. Similarly the local flexibility feasibility studies and domestic DSR projects should look to target non-sandbox arrangements or bespoke/special case arrangements. If a domestic flexibility business model is to work, it needs to be replicable and scalable and not in 'special case' regulatory circumstances.

The rollout of smart meters is a vital component for the feasibility of ECAS. Smart meters are key to verifying domestic DSR and to aggregating loads at the community level. Current progress is slow, with the government seemingly way off its targeted number of installations to be complete by the end of 2020, and there are additional issues around the functionality of first generation smart meters. We need to see a drastic increase in the uptake of second generation smart meters over the next few years in order to keep up with other developments in the market. In addition to this, standardisation and regulation of smart meters, and the method to interrogate the data generated by them, is key to ensuring the value and role that smart meters can genuinely play. Fundamentally, without a smart meter and a robust supporting structure to access the data, cost-effective participation in flexibility at the domestic level is likely to be very challenging, and the technical ability to interface with network operators, Aggregator platforms or the ESO likely becomes unachievable.

The ongoing development of battery technology under the Faraday Challenge, specifically at home battery and EV scales, is another positive policy area, hopefully boosting the round-trip efficiency, capability, shelf life and overall deployment of domestic batteries and take-up of EVs. Alongside controllable electrified heating (heat pumps or electric hot water boilers), EVs and home batteries are the two core technologies that could make flexibility at the domestic and community level viable.

5.3 Regulation of local flexibility

As widely discussed in the industry, Ofgem has required that all six DNOs transition to become DSOs. Ofgem's core function is to protect the interests of energy consumers in GB. This remains a fundamental aspect of their forward-looking work to enable the transition to a decarbonised and decentralised[106] energy system. The DSO, therefore, represents an evolutionary role of the DNO for this future system, in which it "*operates and develops an active distribution system comprising networks, demand, generation and other DERs*"[107].

Ofgem's regulatory framework surrounding the future energy system is to stimulate innovation, support the low carbon transformation and, in keeping with their primary role, to deliver sustainable, resilient and affordable services to all energy consumers in Britain. Many of Ofgem's regulatory objectives lend themselves to developing more specific regulation around the facilitation of local flexibility markets. Specific areas include balancing supply and demand nationally, locational operability of the energy system and to support innovation. As part of their strategy[108] for regulating this future energy system, Ofgem's priorities fall under the following key principles:

- Aligning the ESO's and DSOs' interests with those of consumers, with clear obligations, objectives and incentives
- Ensuring that regulation is non-discriminatory towards technologies, systems or business models,
- Setting regulation that encourages new entrants and innovation, creates a level playing field between entrants and incumbents and between network reinforcement and alternative solutions,
- Providing a reliable regulatory regime which supports efficient investment and risk allocation,
- Promoting competition and harnessing market-based approaches when in the interest of consumers.

The focus of Ofgem's future regulatory framework is concerned with embracing new technologies and services in ways that benefit consumers, while avoiding network upgrade costs, where possible. This approach can be seen as positive for the feasibility of an ECAS model, suggesting that regulation of services will be designed to':

- Maximise existing flexibility opportunities,
- Promote the participation of new and innovative sources of flexibility,
- Look to share financial benefits with consumers, (which is at the heart of the ECAS model).

[106] Referenced in Smart Systems and Flexibility Plan, July 2017: https://www.ofgem.gov.uk/system/files/docs/2017/07/upgrading_our_energy_system_-_smart_systems_and_flexibility_plan.pdf

[107] See ENA Open Networks Project – Workstream 3: DSO Transition, DSO Definition 2018 Product, June 2018: http://www.energynetworks.org/assets/files/electricity/futures/Open_Networks/ON-WS3-DSO%20Definition%20(updated)%20-%20published%20v1.pdf

[108] See Ofgem 'Our strategy for regulating the future energy system, August 2017: https://www.ofgem.gov.uk/system/files/docs/2017/08/our_strategy_for_regulating_the_future_energy_system.pdf

5.4 Industry-led developments

5.4.1 BEIS and DNO engagement workshop

Regen facilitated a meeting with some of the leading DNOs and ministerial advisors. The meeting focused on the DNO to DSO transition, local flexibility markets and how broader participation and neutral markets could feed into BEIS funded local flexibility work and research. In attendance were:

- **Charlie Ogilvie**, Special Adviser to Claire Perry (Minister of State for Energy & Clean Growth),
- **Guy Newey**, Special Adviser to Greg Clark (Secretary of State for BEIS),
- **Nigel Turvey**, Network Strategy and Innovation Manager, WPD,
- **Sotiris Georgiopoulos**, Head of Smart Grid Development, UKPN,
- **Steve Atkins**, DSO Transition Manager, SSEN.

A key theme was that there is still a lot of debate around the roles of National Grid ESO and the DSOs in procuring flexibility. From a community/domestic perspective, it seems likely that a DSO will be a more viable counterparty and BEIS enabling DSOs to work directly with flexibility providers, rather than increasing the role of the ESO, was seemingly encouraged.

The key message from BEIS at the meeting was that they want to see open markets for local flexibility and clear evidence that DNOs are not favouring investment in infrastructure over third-party providers. We can, therefore, expect some action from BEIS to clear external scrutiny of the decision by a DNO to use local flexibility rather than invest in infrastructure and to ensure this is neutral.

There is less focus from BEIS on the type of flexibility providers and potential role of communities/ households. The impression here is that BEIS are focussed more on the role of Aggregators.

5.4.2 Open Networks project

Led by the Energy Networks Association (ENA), the Open Networks project sets out different future models for operation of the electricity system. This project effectively sees the ENA + DNOs acting on the direction of travel from BEIS & Ofgem's Smart Systems & Flexibility Plan. The various models were also discussed with BEIS, UKPN, WPD and SSEN. A summary of the discussion was:

ESO led
The ESO would have the direct relationship with DERs, facilitated by DNOs.

- **Pro:** the ESO has extensive experience of system balancing.
- **Con:** the ESO deals with around 6,000 customers. There are millions of DERs. It would be a major shift for them to have the skills and relationships to coordinate flexibility at a street by street level

DSO led
DSOs would coordinate all DERs and provide an 'aggregated' response at the GSP level

- **Pro:** Clear division of responsibilities, DNO has contractual relationship with millions of customers.
- **Con:** Could lead to competition between DSO and Aggregators to provide services to the ESO. Lack of expertise in system balancing at DNO level.

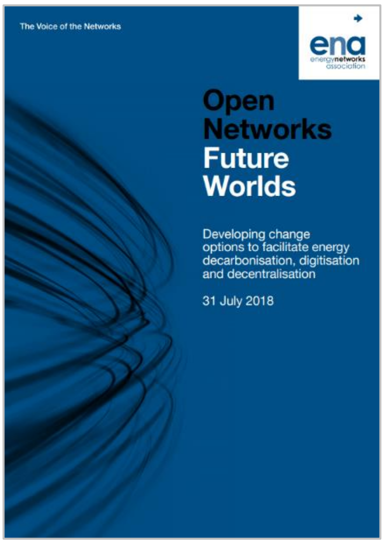
Hybrid/Market led
DERs can provide services to the ESO and the DSO as they choose. ESO and DSO need mechanisms to manage any conflicts that might arise.

- **Pro:** enables market led competition.
- **Con:** could lead to inefficient outcomes.

The clear signal at the meeting was that we are moving to a hybrid/market led approach. DERs, therefore, will need to consider the services they provide at a distribution and transmission level.

5.4.3 ENA Future Worlds Consultation

As part of Workstream 3 of the Open Networks programme, the ENA has published a consultation[109] called 'Future Worlds', which is seeking to share the thinking around how to develop 'change options' to facilitate decarbonisation, decentralisation and digitisation.



The consultation includes:

- A description of five 'Future Worlds',
- A summary of the methodology to build the Smart Grid Architecture Models (SGAMs),
- An overview of why the principle of neutral market facilitation is important,
- Key stakeholder insights for each of the 23 actors described in the models,
- ENA's intended approach to impact assessment modelling of the worlds inviting views,
- A description of the key enablers needed to deliver these future worlds,
- A summary of the ENA's proposed next steps including their work on 'least regrets' analysis

Building on the themes of the Open Networks models, these 5 future worlds develops the types of interactions that might take place between the various actors, and the requirements of facilitating a neutral market. The worlds are outlined in Figure 31, showing how flexibility is to be coordinated.

Figure 31: ENA Future Worlds (source and credit: ENA)

[109] See ENA website: http://www.energynetworks.org/electricity/futures/open-networks-project/future-worlds/future-worlds-consultation.html

- **World A: DSO Coordinates** – a World where the DSO takes a central role for all distribution connected parties acting as the neutral market facilitator for all DER and provides services on a locational basis to the ESO
- **World B: Coordinated DSO-ESO Procurement and Dispatch** – ESO procurement and dispatch – a World where DSO and ESO work together to efficiently manage networks through coordinated procurement and dispatch of flexibility resource
- **World C: Price-Driven Flexibility** – a World where changes developed through Ofgem's reform of electricity network access and forward-looking charges have improved access arrangements and forward-looking signals for Customers. This World has been built with flexibility arrangements as described in World B, but it is recognised that charging and access developments could be similarly progressed in other Worlds
- **World D: ESO Coordinate(s)** – a World where the ESO takes a central role in the procurement and dispatch of flexibility services as the neutral market facilitator for DER with DSO's informing the ESO of their requirements
- **World E: Flexibility Coordinator(s)** – a World where a national (or potentially regional) third-party acts as the neutral market for DER providing efficient services to the ESO and/or DSO as required.

These five worlds represent a wide range of potential options for the future. It would appear that 'World C' looks overall the most likely pathway for a flexibility market as it currently stands, given the proposals outlined in the Smart Systems and Flexibility Plan. This would involve market-led competition and likely a hybrid approach with both the ESO and DSOs coordinating DER-led flexibility services.

Essentially this could be seen as an assessment of the conflict between the ESO and DNOs, over how national and local balancing needs are coordinated and by who. The variety across the five worlds questions whether the ESO is set to be in control of coordinating all DERs or if DNOs (DSOs) are set to essentially manage everything below the Grid Supply Point (GSP).

The ability for the ESO to coordinate and deal more directly with millions of local customers is potentially a difficult concept. Equally all flexibility procurement passing through the DSOs is likely not a favourable option for Ofgem or BEIS, with the potential for it to be locally too sewn-up. The answer may therefore be a form of price-driven market, where ESO and DSO set out their needs, the market responds and both parties have to coordinate behind the scenes to avoid any conflicts. It is also essential that this coordination avoids unintended consequences, such as the ESO wanting a turn-down and DSO wanting a turn-up response simultaneously.

On the whole, smaller decentralised generators and storage companies would naturally liaise with their local DSO, but if the market signal is clear, the responding DER asset/party probably isn't too concerned with who they are providing the operational benefit to, as long as the benefit is realised.

5.4.4 European distribution network standards around flexibility

The Council of European Energy Regulators (CEER) set out its views of the DSO's role in accessing flexibility services and fostering a suitable environment for the provision of flexibility, following on from its public consultation on Guidelines for Good Practice for Flexibility Use at Distribution Level[110]. A position echoed and stated by Ofgem, CEER's guiding principles stress that DSOs should be non-discriminatory towards technology when procuring sources of flexibility that benefit the network, and they should be able to use flexibility services provided by network users (i.e. DERs) to help manage the distribution network, effectively driving the creation of flexibility markets in the European countries.

CEER has also developed a set of high-level guiding principles for National Regulatory Authorities (NRAs), resulting from this consultation. These guiding principles can be summarised as follows:

[110] See CEER consultation, Spring 2017: https://www.ceer.eu/flexibility-use-at-distribution-level

- The regulatory framework for DSOs should be non-discriminatory and not hinder DSOs from facilitating the development of flexibility and markets therein. Specifically, all sources of flexibility that benefit the grid, including generators, storage, and DSR, should be treated in a non-discriminatory manner when procured by network operators – regulatory incentives should avoid any bias towards specific technologies that deliver flexibility
- The regulatory framework should enable the development of a full range of possible flexibility services, while also ensuring that the framework is sufficiently robust deliver the best outcomes for consumers and the system as a whole
- NRAs should ensure that no options are prematurely ruled out
- DSOs should be able to, under the relevant regulatory frameworks, access and use flexibility services provided by grid users for managing the distribution network, where the use of this flexibility is considered to be the most economical solution and avoids undue distortion to markets and competition
- Within the framework set by the relevant European legislation, the details on the roles and responsibilities of DSOs should be determined at national level, given the diversity of situations, legislation and needs across EU Member States and the variation of DSOs in size and location
- It is vital to differentiate between the use of flexibility by market actors and the use of flexibility that benefits the grid by the DSO. Due to their different competitive, technical and regulatory conditions, the source of flexibility may be the same, but the purpose is different
- Intensify the discussion on principles and roles and responsibilities regarding DSO-ESO coordination in the field of flexibility.

As with Ofgem's own regulatory framework principles, these guidelines give explicit mention to an 'agnostic' approach to procuring flexibility at the distribution level. Such a principle is nominally positive for a model such as ECAS seeking to enter local flexibility markets, especially with one of the core roles of the ECAS model to share/provide financial benefit with/to end domestic consumers.

5.4.5 The regulation of Aggregators

5.4.5.1 Ofgem consultation

Ofgem's view is that permitting independent Aggregators (i.e. those not also acting as suppliers) to gain access to additional markets like the BM, can deliver benefits to the consumer, provided it's under carefully designed regulation[111]. This will be made easier by ensuring a level playing field in the access to markets for participants, leading to increased competition, while the Aggregator bears the balancing costs and delivery risks as opposed to the customer. Ofgem also state that payments for sold-on energy should be agreed in the retail contract between the supplier and the end consumer. They do anticipate lessons to be learned once these arrangements become more widespread as the market grows.

5.4.5.2 Aggregators entering the Balancing Mechanism

Ofgem granted derogation to Limejump[112], allowing it to participate in the BM, by submitting aggregated data at the GSP level, rather than individual assets within a GSP. In practice, LimeJump have entered the BM by firstly becoming a licenced supplier and creating a Virtual Power Plant (VPP), aggregating distributed renewable energy generation, battery and DSR assets[113]. Within LimeJump's VPP

[111] See Ofgem letter regarding allowing Aggregators to enter additional energy markets, July 2017: https://www.ofgem.gov.uk/system/files/docs/2017/07/ofgem_s_views_on_the_design_of_arrangements_to_accomodate_independent_Aggregators_in_energy_markets.pdf
[112] See Ofgem decision letter in regards to LimeJump derogation, July 2018: https://www.ofgem.gov.uk/system/files/docs/2018/07/limejump_grid_code_derogation.pdf
[113] See LimeJump press release: http://www.limejump.com/limejump-enters-balancing-market/

is also the first battery storage site that has entered the BM, a 10 MW battery operated by Anesco in Derbyshire. Whilst very positive precedents, other organisations acting in a similar role of an Aggregator with a supply licence are also actively trading in the BM, such as Flexitricity[114], who targets DSR aggregation specifically. These organisations are evidently blazing a trail for aggregated flexible energy assets, accessing value from more than one energy market. This provides a positive landscape for smaller entrants into these markets, with Aggregators once more providing a potential route to market.

However, whilst likely a lucrative market to be in, the entry and operating requirements of BM are almost certainly more stringent and restrictive than even National Grid's Power Responsive programmes or the local flexibility services that we have discussed here. This therefore means that the potential for domestic loads being able to enter the BM may be a technically challenging prospect.

With the right aggregation platform interfaces, the right 'readily dispatchable' technologies (such as home batteries or EV charging equipment), the potential for ECAS to access the BM could be explored further. Alternatively, ECAS could potentially be better placed to aggregate domestic/community level flexibility, then offer that to a licenced Aggregator such as LimeJump, Flexitricity or Upside to operate within the BM. The added commercial arrangement and related contracts would need to be considered carefully, alongside the division of risk and value.

5.4.5.3 Aggregator Code of Conduct

The Association for Decentralised Energy (ADE) is in the process of developing a 'Code of Conduct' for Aggregators to help build confidence amongst DSR providers and advance flexibility opportunities[115]. The Code of Conduct will be mainly targeting these following areas:

- **Sales and marketing** - ensuring an honest and technically proficient relationship between Aggregators and customers, allowing customers to make decisions based on accurate information to promote high performance in the industry
- **Technical due diligence and site visits** - ensuring the best practices to protect data and assets from cybercrime, as well as requiring that member installations be built to ensure protection of employees and liability coverage in the event of an accident
- **Proposals and contracts** - ensuring that tenders are fair and accurate, with benefits and risks clearly laid out, so as not to deceive customers into signing up for services they do not want or need and enabling Aggregators and customers to enter into mutually beneficial agreements
- **Complaint handling** - requiring members to give continued support to customers after a contract has been signed, helping disputes to be resolved in a timely and attentive manner.

The code has been developed by a committee of Aggregators, suppliers and industrial customers. It will be voluntary and industry-led and is due to be implemented later this year[116].

5.4.6 Considerations for the ECAS model

These industry-led consultations stress the ever-increasingly important role of the DSO, coordinating with the ESO, in facilitating a suitable environment for a range of flexibility services. This role must include procuring flexibility at the community level when it is practical and economically viable to do so.

For the ECAS model, the DSO remains one of the most likely counterparties when providing flexibility services aggregated from the domestic/community scale. From an industry perspective, it seems the direction of travel for the procurement of flexibility is to continue to be driven by markets, with

[114] See Flexitricity DSR in the BM: https://www.flexitricity.com/en-gb/energy-supply/balancing-mechanism/
[115] Code of Conduct referenced as a wider initiative in National Grid's Demand Side Flexibility Annual Report 2017: http://powerresponsive.com/wp-content/uploads/2018/02/Power-Responsive-Annual-Report-2017.pdf
[116] See ADE Code of Conduct consultation, July 2017: https://www.theade.co.uk/news/ade-news/ade-demand-side-response-code-of-conduct-consultation

individual sites and Aggregators bidding to provide services to both the DSO and ESO. Who takes on the mantle of coordination may have a material effect on the ability for smaller participants to enter and operate in flexibility markets. If successful, Ofgem's proposed network access reforms could act as an enabling factor to improve the viability of ECAS.

It is promising that both Ofgem and CEER acknowledge the need for regulatory and market arrangements that enable consumers to benefit from innovation and new services, as this is a key principle which an effective ECAS should deliver. Regulatory framework principles from Ofgem and CEER stress the protection of consumer interests if DSOs are to use flexibility to manage their networks. If there is a truly level playing field that enables small-scale and new technologies to access the local flex markets alongside larger incumbents, ECAS ought to be a feasible flexibility option for DSOs to turn to.

The ADE code of conduct, when released, is an opportunity for Aggregator parties to standardise approaches and gain credibility with potential entrants to flexibility markets. If successfully implemented, this code of conduct is something an ECAS may wish to voluntarily adhere to as a form of reputational or quality standard. In contrast, this may be more of an 'upward-facing' standard for an ECAS potentially intending to interface or offer flexibility to other Aggregators. The average domestic householder or community energy group may have little interest or awareness of this code of conduct.

Regulation to ensure minimum standards for smart appliances should advance their uptake in households, in turn giving an ECAS access to a greater portfolio of aggregated assets. However, smart appliances are likely to remain a low or limited source of flexible capacity in the home.

5.5 Legal considerations and barriers

5.5.1 DNO to DSO transition:

A community Aggregator flexibility provider may incur licence issues, in regards to sourcing DNO income streams and providing services to domestic and non-domestic end users. DNO income streams are also still quite uncertain at present, given the current pruning/simplification of the services sought.

Initially, Ofgem legislated against DSO holding storage assets. This could create a regulatory barrier in the DSO not being permitted to hold small-scale storage contracts with the ECAS (see Ofgem 2017). However, alternative grid connections and ANM can pave the way for some flexibility in that the DNOs are permitted to engage in ANM through regulation and have guidance for participation written by the ENA. This could also be seen as a barrier due to the DNO being able to constrain through own measures without procuring flexibility services.

Work by the Smart Grids Forum concluded that the regulatory framework does not prevent commercial arrangements in the market. Including DNOs using third parties to help provide services, work on flexibility is looking at what more needs to be done to support efficient use of flexible resources across the system (both RIIO-ED1 and ED2).

In addition to this, as referenced by Ofgem under RIIO, DNOs are permitted to recover 1% of revenue, by offering small-scale reward services such as flexibility which they do themselves, rather than open to the market. ENW's innovation project 'Customer Load Active System Services (CLASS) is an example where a DNO could potentially bid into the ancillary services market. This project is therefore a revenue-deriving project for ENW, but they will be unable to offer it on an open market as they will have reached the 1% cap and because there is no need if it is a success on its own as a revenue provider to the DNO.

Historically, DNOs were incentivised through capex pricing to deliver a large-scale network and not to provide localised services, except through innovation. This incentivisation is changing as part of the transition to a DSO, with cheaper, more localised solutions being incentivised. The regulatory position still exists in which DNOs have to calculate their expenditure in building and operating large networks.

5.5.2 Licence conditions and codes

A review of the National Electricity System Security and Quality of Supply Standard, SQSS, and other relevant standards and codes should be undertaken to determine if changes were required for ECAS. Engagement with licensed suppliers would also be a key area of focus, assessing the need for 'licence lite' or no licence at all. In addition to this, understanding what future market supply arrangements need to be considered, the contracts for multiple suppliers and what obligations would be on the ECAS facilitating company, should be considered.

5.5.3 Smart metering

The smart metering system is not yet uniform with a number of considerations around SMETS1 vs SMETS2 and compliant software interfaces and interaction with in-the-home devices and appliances. Related to this are the issues around suppliers not meeting their rollout targets and how this will be addressed by Ofgem, BEIS as the rollout targets move closer. Regulatory dangers of changes to roll out and the type of smart meter may cause any proprietary control devices installed as part of the ECAS model, to need to be future proofed against these mandated changes.

Similarly, the consideration around elective or mandatory half hourly settlement (HHS), and who can access the HH data, will also need to be considered. Mandatory HHS can be seen as a positive thing for flexibility markets and Ofgem are trying to bring this forward for domestic consumers. At present it is not mandatory and discussion from Ofgem suggests that there is some concern that domestic consumers, when given the option through smart meters, are not taking it up. If mandatory HHS becomes legislation this will drive the benefit, but it may be that Ofgem decide it is not in the consumers' interest. The position on mandatory HHS and smart meter regulation is another area that is very unclear. Barriers exist through both the lack of regulation or legislative commitment, but also mostly in consumer distrust of both electricity suppliers and what HHS will mean for customer bills.

5.5.4 Power Purchase Agreements (PPAs) and customer contracts

In relation to flexibility services being provided to ECAS, the consideration of a corresponding PPA between the domestic users and ECAS being required would need to be factored in, as some services would require individuals to become energy exporters (EVs, storage discharge, time-shifted rooftop PV generation etc.).

As part of the participation contract between ECAS and individuals, would penalties for non-compliance/performance (from any flexibility contracts) be passed on to individual non-responders? Or would this be soaked up as part of the ECAS risk profile, from i.e. oversubscribing compared to flexibility bid. This is again similar to existing Aggregator models and the arrangements they have with the ESO (or soon-to-be DSO) and thus the corresponding arrangement between Aggregator and provider.

5.5.5 Other legal considerations

- Employment law issues may crop up as the community group may need to employ front line staff to deal with end-user support and consultants/traders to deal with the flexibility market interactions and contractual operations.
- Consent requirements under GDPR in relation to the data involved, potential difficulties with GDPR and access to meter data.
- The uncertainty of Brexit and what effect this will have on regulation, single energy market, UK participation in decarbonisation programmes such as the Emissions Trading Scheme etc.

V2GB

Vehicle to Grid Britain

Project coordinator:

elementenergy

Element Energy Limited
Energy Systems Catapult
Cenex
Nissan Technical Centre Europe
Moixa
Western Power Distribution
National Grid ESO

Executive Summary

This study assesses the long-term viability of V2G in a changing power system in Great Britain (GB) as well as the early opportunities in British power markets. Drawing on the diverse expertise of consortium members Nissan Motor Manufacturing UK, Energy Systems Catapult, Cenex, Moixa, Western Power Distribution, National Grid ESO, and Element Energy, the project explores both near term niches and enduring large-scale opportunities for V2G to play a role in a flexible energy system in Great Britain.

The value of V2G

a. There is added economic value which can be accessed by using V2G chargers compared to Smart Charging. However the scale of this value per domestic customer is extremely variable and is impacted by a wide range of factors including: usage of the charge point, the behaviours of user(s), and charger location.

b. The plug-in rate is a key driver for value captured from V2G. Average plug-in rates currently appear to be low (around 30% of time plugged in) according to the EV charging data available to this project. In the case of a high plug-in rate driver archetype (75% of time plugged in) a 7kW V2G charger could capture annual revenues of around £436 - four times that achieved with the average plug in rate. Nearly all of this value would be from providing services to the System Operator (SO), mainly FFR.

c. There could be an opportunity for Smart and V2G charging to generate significant revenues where it is in a DNO congestion management zone. Using estimates of revenue from this nascent market, where congestion is acute and sustained, the value per EV could be £250/EV.year or more. The opportunity will be geographically restricted and the most valuable opportunities are expected to be time limited as they will compete with network upgrades.

d. On the wholesale electricity market, a simple Economy 7 tariff would unlock most of the value achievable with a responsive half-hourly tariff. This may change in the future, if price spreads and volatility increase. Using Smart and V2G charging as a flexible asset into the imbalance market could also support more responsive tariffs.

e. After FFR, additional grid services offer diminishing returns due not only to lower prices, but also the service is only required during certain windows during the year.

f. If grid services to the SO and DNO are excluded, then Smart Charging is able to capture 80% of the value of V2G.

The cost of V2G

g. The on-cost of providing bi-directional V2G charging is dominated by the hardware cost. This makes it challenging to generate positive net revenues; profitable opportunities are restricted to very narrow types of BEV users (e.g. high plug-in, home solar exists, and residing within a constrained network with a market mechanism to reward congestion management).

h. Top-down (learning rate) and bottom up (component based) projections of V2G costs aligned to predict a premium of ca £650-1150 for a 7kW V2G charger in 2030. Thus hardware is expected to continue to dominate annualised V2G costs (if depreciated over 5 years), and remains a major component of costs if depreciated over 10 years.

i. The requirement for the services of an aggregator also places restrictions on which business models can provide returns on investment, especially in the case of Smart uni-directional charging.

Risks to revenues

j. As EV numbers grow (alongside other flexibility assets), saturation could be reached in low-volume services, especially in System Operator services. There is significant risk to revenue for V2G, with at least half the overall revenue per EV at risk from falling FFR prices. Our analysis of 2030 revenues with low FFR prices (reflecting competitive supply) showed this service would no longer dominate residential V2G revenues.

k. Providing a Smart Charging and V2G congestion avoidance service to the DNO could become a significant revenue stream. However, markets are nascent and all projections should be treated with caution. Furthermore, these revenue streams are highly location specific (high value only where congestion is acute) and time sensitive (as the DNO may reinforce the network).

l. Any V2G-induced adverse impacts on the battery or on the driving experience need to be avoided; otherwise they could dominate costs and erode the value case.

Whole System value and decarbonisation potential of V2G

m. There will be an enduring value from variable/smart charging and V2G to the electricity supply chain, both in terms of local flexibility to the distribution grid and increasingly in energy arbitrage as price spreads and volatility increase with RES deployment.

n. By reducing the peak demand on the distribution grid, deployment of V2G could help save £200m of cumulative distribution network investment from 2020-2030 compared to unmanaged charging.

o. Relative to unmanaged charging, Smart Charging could generate GB whole energy system net savings of £180m annually (in 2030), with benefits throughout the GB power system. Additionally, V2G operation could generate a net saving of between £40M-90M/annum, depending on limits to V2G energy throughput.

p. V2G will compete with a range of technologies to provide flexibility to the system, in particular with stationary battery storage, 2nd life batteries, flexible gas plants, and Smart Charging.

q. Competition between flexibility sources means that the marginal value of flexibility reduces as its deployment increases. However there is a positive synergy when increasing both flexibility asset and VRES deployment; VRES induced variability provides the conditions to sustain cycling and revenues from flexibility assets, which in turn can reduce curtailment of renewable energy.

Recommendations

a. To maximise revenues from SO services, near-term deployment of V2G in the residential market should focus on consumer groups with plug-in rates much higher than average.

b. Positive net-revenues can emerge as a result of stacking of revenues. V2G developers should be prepared to stack revenues from multiple sources, to combat potential erosion of value (due to market saturation or time-limited revenue opportunities).

c. While passive EV charging may worsen congestion on distribution networks, where possible deployment of V2G should be focussed in areas where the DNO has acute congestion issues and will reward Smart and V2G charging for congestion avoidance.

d. Our analysis indicates a combination of nascent technology and scale production would reduce V2G hardware costs significantly. This must be achieved to permit V2G to operate profitably outside of niche areas and allow the technology to make a contribution to decarbonisation.

e. Commercial models must be developed that allow the hardware cost to be depreciated over long periods of time.

f. The current testing and participation regime for Balancing Services (predominantly Firm Frequency Response) results in prohibitively high costs for providers of domestic DSR. National Grid ESO should work with industry to develop innovative ways to meet the SO requirements, increase liquidity in Balancing Services markets and drive value for the end consumers.

g. To reduce concerns about range anxiety, consumers should have access to high-range EVs and have ample rapid charging availability. Business models will need to be developed to reduce customer concern about V2G-based adverse impacts on the battery. Feedback issues (such as larger batteries reducing plug-in times) will need to be evaluated as the sector develops.

h. The net positive contribution that Smart and V2G charging can make to GB Power system costs should be taken into account when considering support which allows the sector to become established. Long-term revenue certainty (such as provided by FITs to the PV industry) could be explored as a means of supporting early adopters of V2G.

Acknowledgements

The feasibility study V2GB - Vehicle to Grid Britain is part of the Vehicle-to-Grid competition, funded by the Office for Low Emission Vehicles (OLEV) and the department for Business Energy and Industrial Strategy (BEIS), in partnership with Innovate UK. The project partners would like to thank Innovate UK for their funding which was vital to make this project feasible.

Contents

Glossary

Term	Explanation
Arbitrage	Net revenues generated by V2G selling electricity at a higher price than bought. This can be realised by selling electricity to an external party or by offsetting home electricity demand allowing to shift some of this demand to times of lower electricity prices.
Commercial EV	An EV used for commercial purposes. This includes e.g. fleets of delivery and taxi companies as well as car rental services. Commercial EVs differ from Residential EVs in terms of typical EV models as well as in terms of their driving and plug in patterns.
Customer	Business party for which products and services are developed and offered. This can be for example the EV owner (in the case of offering a service to reduce the EV owner's electricity bill) but also the System Operator (in the case of offering System operator services such as Frequency Response) or another stakeholder of the electricity system.
DNO services	Services offered to the electricity Distribution Network Operator (DNO). DNOs are beginning to develop markets for services helping them to operate the electricity distribution grid, such as local congestion management.
DTU	Demand Turn-Up is a service procured annually by National Grid ESO to help manage short term energy imbalances by paying I&C consumers to change their operating patterns. National Grid ESO is not procuring DTU in 2019 after a review of the service (https://www.nationalgrideso.com/balancing-services/reserve-services/demand-turn?market-information).
ENTSO-E	European Network of Transmission System Operators - electricity
FFR	Firm Frequency Response is the monthly tendered market used by National Grid ESO to commercially procure frequency response services
Import savings	Savings incurred by EV owners on their electricity bills as a consequence of shifting their electricity consumption to times of lower electricity prices via Smart Charging.
Peak day	The day which has the highest electricity demand of the year. Usually this day is in the winter months.
Plug-in rate	The percentage of hours per day for which the EV is connected to the EV charger.

Term	Explanation
Residential EV	An EV connected to a residential charger and used by the household..
Smart Charging	The percentage of hours per day for which the EV is connected to the EV charger.
STOR	The time and rate at which EVs charge is adjusted according to the needs of the electricity system while still satisfying EV drivers' driving requirements.
System Operator	The operator of the electricity transmission system. In Britain, The System Operator is National Grid ESO.
System Operator services	Services offered to the electricity transmission system operator to maintain frequency and voltage of the electricity grid within the statutory limits. Such services include Frequency Response, Reserve and Reactive Power.
TRIAD	The Triads are the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year, separated by at least ten clear days. National Grid ESO uses the Triads to determine TNUoS demand charges for customers with half hourly meters.
TRIAD Avoidance	The act of forecasting a likely Triad day and reducing demand or increasing onsite generation in order to minimise the calculated TNUoS demand charges for the following year. This has the benefit of avoided cost to the consumer, and avoided need for peak investment or constraint for the system operator.
Unmanaged charging	EV drivers plug in at the time of arrival and charge their EV at the maximum charger capacity until the EV battery is fully charged, without reacting to any signals or needs of the power system.
V2G	In addition to Smart Charging Capabilities, EVs can export electricity from their batteries back to the grid.

Introduction

Introduction

Vehicle-to-grid (V2G) technologies are expected to play a key role in the decarbonisation of Britain's transport and energy systems. Connecting millions of EVs and coordinating their charging and discharging would minimise the costs of EV charging while allowing the grid to balance the integration of high levels of variable renewable energy sources.

This feasibility study V2GB - Vehicle to Grid Britain is part of the Vehicle-to-Grid competition, funded by the Office for Low Emission Vehicles (OLEV) and the department for Business Energy and Industrial Strategy (BEIS), in partnership with Innovate UK.

Drawing on the diverse expertise of consortium members Nissan, Energy Systems Catapult, Cenex, Moixa, Western Power Distribution, National Grid ESO, and Element Energy, the project explores both near term niches and enduring large-scale opportunities for V2G to play a role in a flexible energy system in Britain.

The project has four primary objectives.

Assess the long-term market opportunity

To assess the potential size of the market for V2G in the UK in the long-term, by establishing the underlying drivers for market needs. This fills a gap in stakeholder understanding of the long-term viability of V2G, distinguishing V2G from other future sources of flexibility and evaluating the size of the opportunity across several scenarios.

Identify early opportunities

Understand the potential customers of V2G and identify the most promising archetypes. Evaluate possible V2G revenue streams in the near term and identify which ones offer highest revenue over the short term. Perform a detailed evidence-based analysis of key customer and revenue stream combinations to quantify likely near term revenues that V2G can capture.

Getting started

The study identifies and analyses business models and value chains to understand how V2G should be structured to be commercially viable.

Support scale up

The study will explore pathways for scaling up a V2G business to play a full role in a flexible and efficient energy system. The project will determine what performance thresholds are required to maintain and grow the market as it transitions from early adopters towards representative EV clients.

Long-term market revenues and drivers

2.1 Introduction

This chapter summarises the work performed by the Energy Systems Catapult under the Innovate UK funded project V2G-Britain. Work Package 1 (WP1) investigates the long-term market value and where V2G might be applicable in a wider energy system context. WP1 is focussed on the 2030 horizon and is separated into three deliverables with each deliverable including a different part of the analysis.

The first report from WP1 summarises the findings from the literature review and research to identify the drivers and dependencies that affect the value and viability of V2G. The outputs of this work have helped to inform the development of the scenarios for the second part of the work package, which includes the use of a modelling capability to help understand at what level V2G might be utilised in 2030. The final portion of the work package provides estimates of the system flexibility requirements and the V2G market potential.

2.2 Literature review

The literature review identified the services that are accessible by V2G and these are shown in the diagram below.

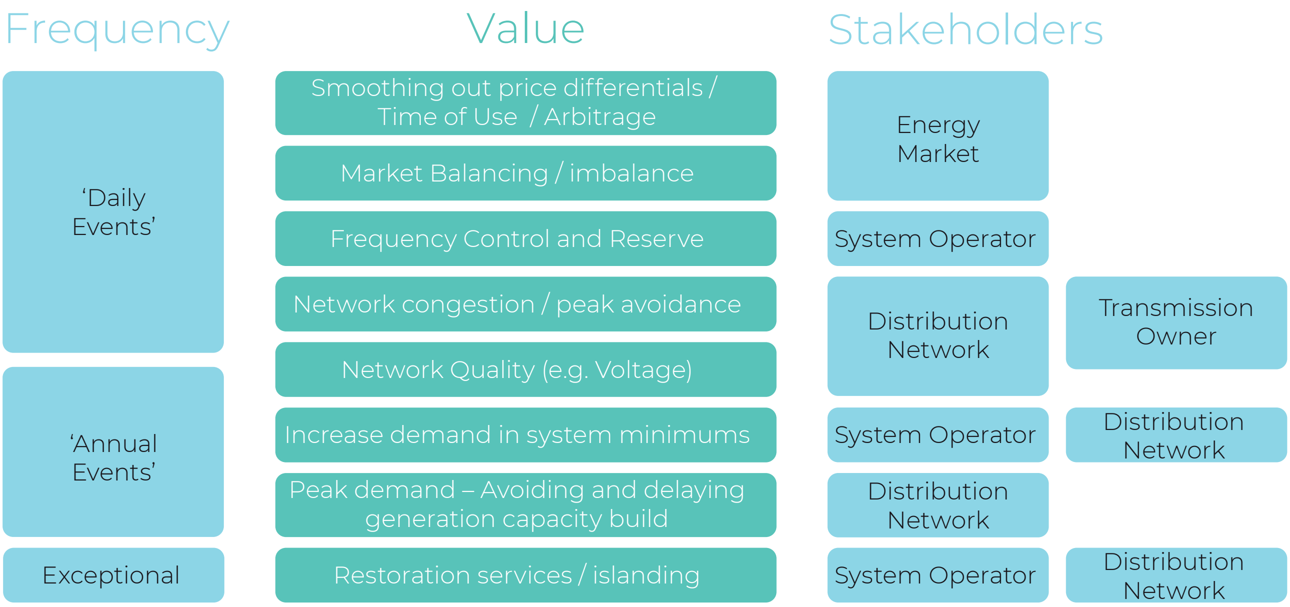


Figure 1: value streams accessible by V2G

The literature review has also identified competing flexibility providers to V2G and a series of other challenges. The principle flexibility competition comes from peaking plant, grid-connected electricity storage, in-home heat storage, residential backup boilers and interconnectors.

2.3 Energy system modelling

The subsequent analysis draws on the key drivers and dependencies identified from the literature review and has been carried out using modelling capability licensed to the Energy Systems Catapult and developed in the ETI's Consumers, Vehicles and Energy Integration (CVEI) project. The modelling capability encapsulates the whole energy system, covering the different forms of energy supply, network infrastructure and end-use sectors, whilst providing a higher level of fidelity for the transport sector. This has been used to support the analysis of how intermittency and demand variability affect the utilisation of V2G out to 2030.

To enable the analysis, V2G has been incorporated into a whole energy and transport system modelling capability. This approach has identified some valuable high-level conclusions about the impact of V2G on the whole energy system and the role it can play. The analysis has not taken account of additional cost of equipment required to enable V2G nor the impact on battery degradation.

The role of V2G was assessed through two main scenarios; in the baseline scenario the energy system in 2030 is modelled which is consistent with a trajectory to meeting the UK's 2050 greenhouse gas emissions targets. The second scenario was a sensitivity analysis considering the impact that high intermittent generation volumes will have on the system. Two alternative vehicle charging strategies were also modelled for each of the scenarios: an unmanaged charging case, where it is assumed that V2G is not deployed; and a managed charging case. These alternative charging strategies were used to understand the potential impact that V2G could have on the energy system. The main conclusions from the modelling work were:

V2G reduced the requirement for additional grid-connected electricity storage in 2030 and the need to use that storage.

Figure 2 and Figure 3 show both the injection into and withdrawal from V2G. In some cases, V2G is not used because the available capacity is not there, i.e. the vehicle is not at the required state of charge or plugged-in. In both days (peak and winter) during the overnight periods energy is injected into the aggregated V2G storage. During the summer day, the utilisation of vehicle storage capacity is close to zero; this is a result of low electricity demand.

2.3 Energy system modelling cont...

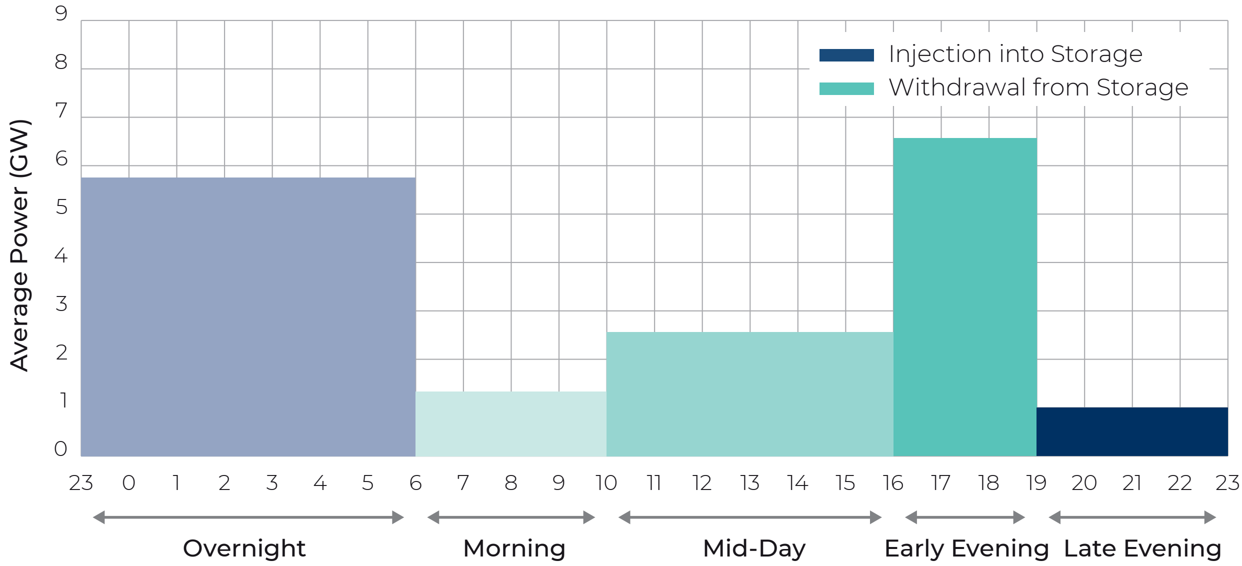


Figure 2: 2030 – V2G injection and withdrawal during peak day – Baseline scenario

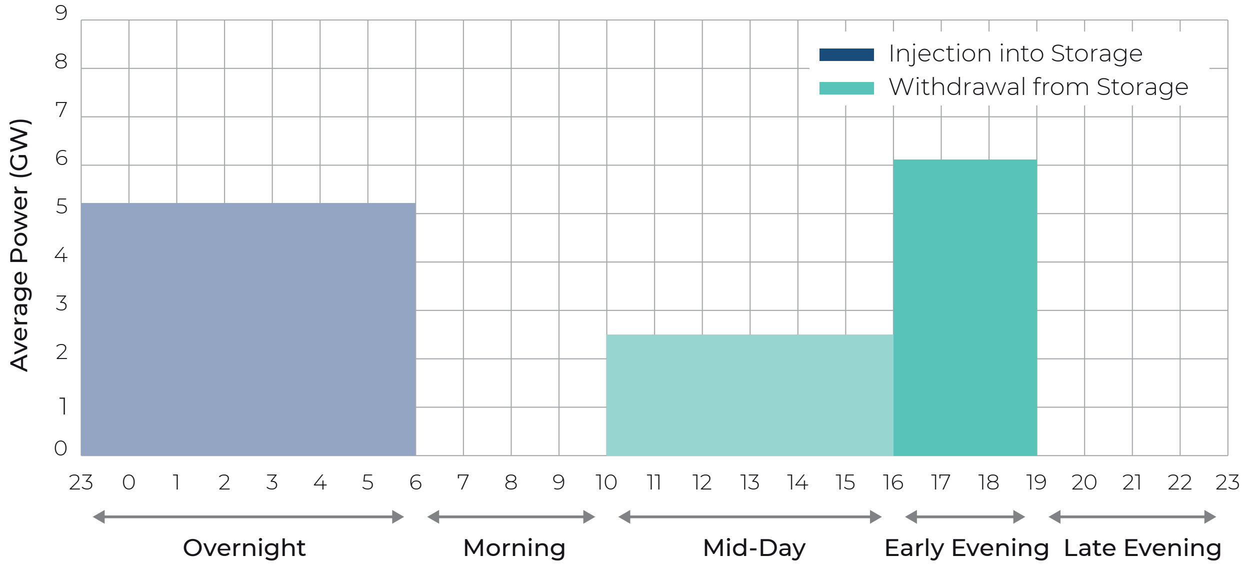


Figure 3: 2030 – V2G injection and withdrawal during winter day – Baseline scenario

Figure 4 and Figure 5 show the injection and withdrawal from V2G in the peak and winter days. Solar power is not available overnight and flexible generation is reduced overall in the high flexibility scenario, more specifically in the overnight period it is reduced by 35%. Therefore, there is no available energy to fully charge and utilise V2G in the winter overnight period, which leads to reduced utilisation during the day.

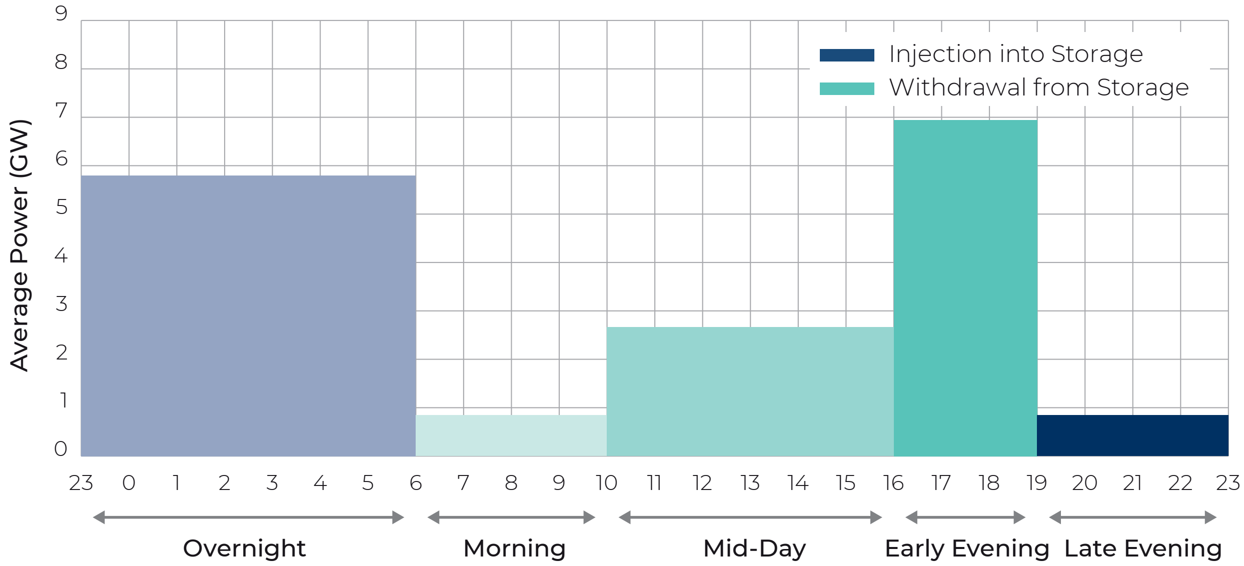


Figure 4: 2030 V2G injection and withdrawal during peak day – High flexibility scenario

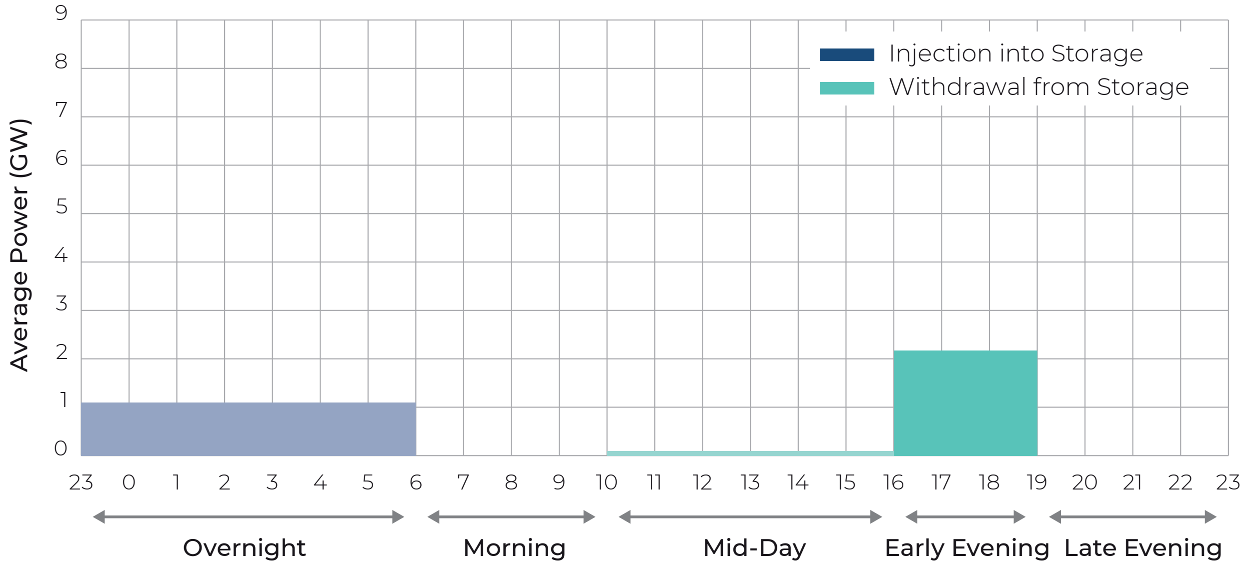


Figure 5: 2030 V2G injection and withdrawal during winter day – High flexibility scenario

When V2G was deployed, the installed capacity of flexible generation plants, e.g., Combined Cycle Gas Turbines (CCGTs), was reduced.

Furthermore, the CCGTs that were present had a higher utilisation levels when V2G was deployed.

2.3 Energy system modelling cont...

The differences in the installed electricity generation capacity and annual electricity production between the case where V2G is deployed and when V2G materialises are seen in Figure 6. The installed capacity of plants with low flexibility and intermittent generation sources remain the same in both cases, whereas flexible generation installed capacity is higher in the unmanaged charging case. The same can be seen in the annual electricity production. The electricity generated from flexible plants is higher when V2G is not deployed (Figure 7).

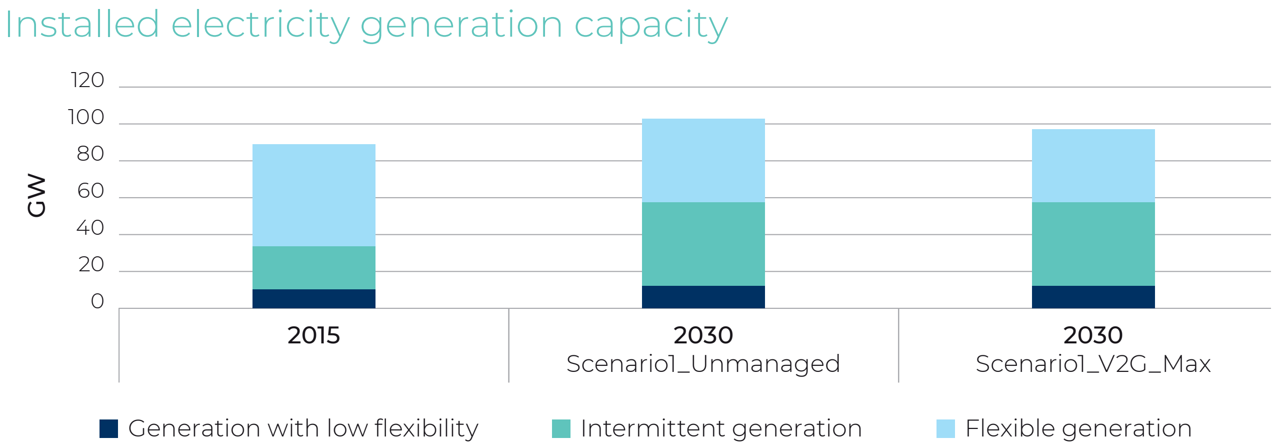


Figure 6: 2030 – Installed electricity generation capacity – Baseline scenario, Unmanaged charging and V2G cases

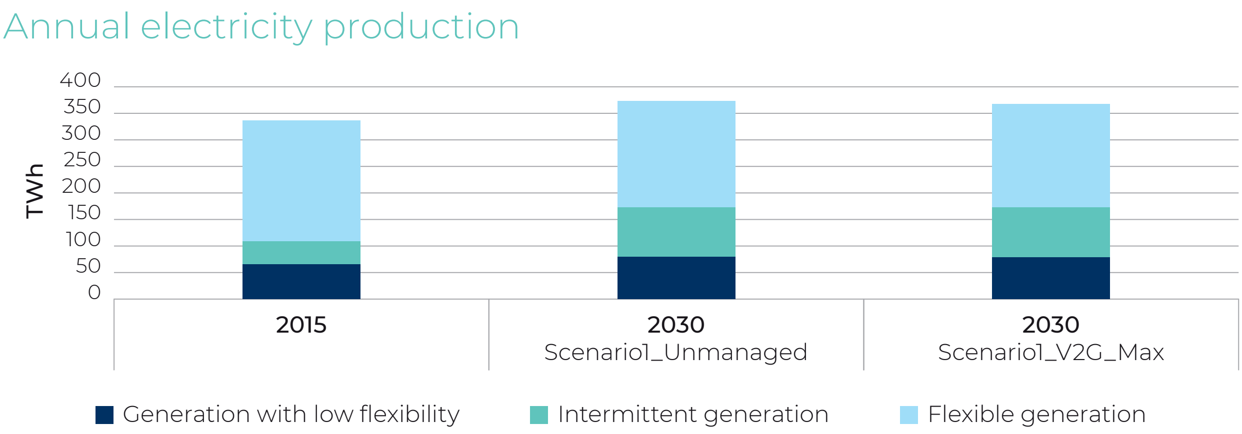


Figure 7: 2030 Annual electricity production – Baseline scenario: Unmanaged charging and V2G cases

The impact of V2G on the installed capacity and generation from flexible plants is seen in Figure 8. The installed capacity is higher in the unmanaged charging case by 5GW, generating 2% more energy. Even though the flexible generation installed capacity is higher, the utilisation of the plants is lower when compared to the V2G case.

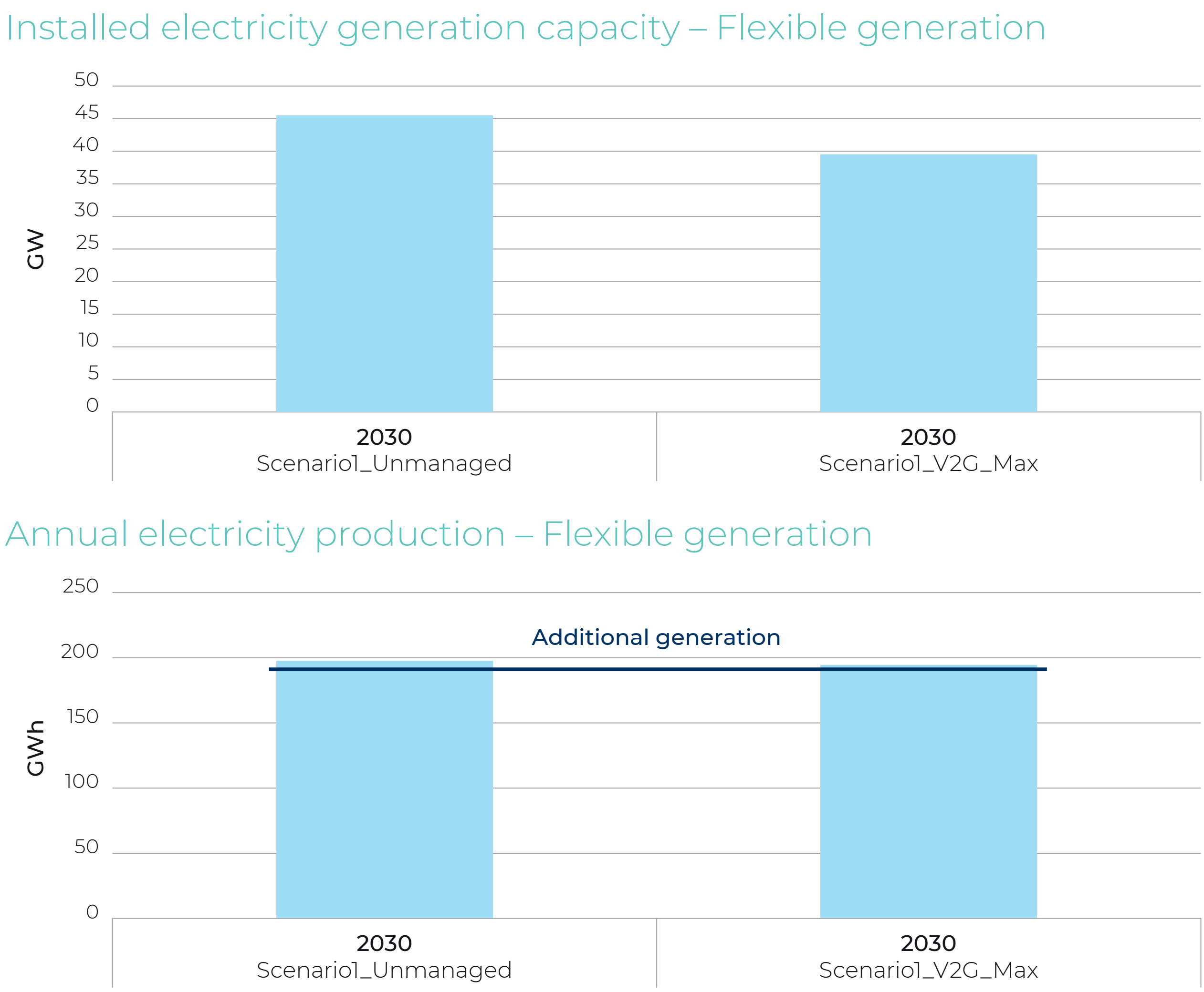
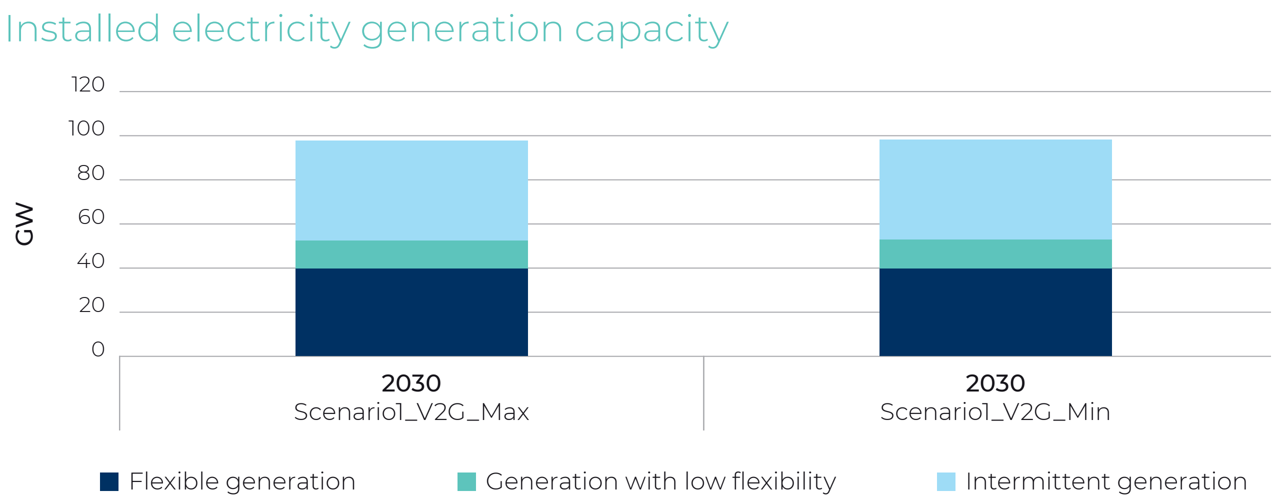


Figure 8: 2030 – Installed electricity generation capacity (top) and annual electricity production (bottom) from flexible plants – Baseline scenario: Unmanaged charging and V2G

There are diminishing returns associated with increased availability of V2G i.e. the flexibility market is finite.

2.3 Energy system modelling cont...



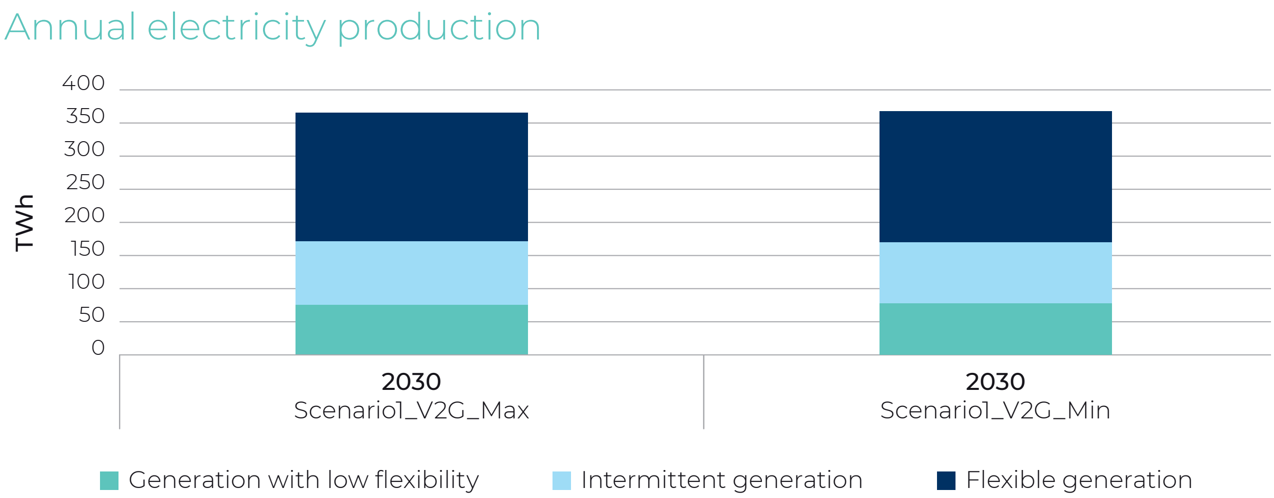


Figure 9: Installed electricity generation capacity (top) and annual electricity production (bottom) – Baseline scenario: V2G Max and Min cases

Based on this assessment, it suggests that there will be an enduring value from variable/smart charging and V2G to offer services to the electricity supply chain and that EVs are technically suited to do so, provided they are connected to the electricity system. However, there are important considerations to be made on how this value is enabled, from the inducements that may be offered, through to the market mechanisms and information exchanges that will be needed.

2.4 V2G market potential

2.4.1 Market Arrangements

The viability, and potentially the necessity of, flexibility adopted by EVs will be influenced by the way energy and network costs are billed to consumers, the way services to the energy supply chain are rewarded and the market arrangements that accompany them.

There are many developments that are underway now by Ofgem, the industry regulator, network companies and the System Operator that may allow EVs to better engage with the electricity system including the definition of services, network charging arrangements and market frameworks.

2.4.2 Market opportunity for smart/variable charging and V2G

There is undoubtedly value in charging flexibly and offering flexibility in the short term, which is likely to be sustained for a period of time. As the number of EVs grows, some relatively low volume services could reach saturation. The point at which this might happen is uncertain and will be based on the number of EVs available, participating and importantly competition from other flexibility providers. This is particularly the case for many System Operator services that are less locational specific, such as frequency response and reserve.

Ultimately, smart/variable charging and V2G can offer similar services and large numbers of EVs in smart/variable charging mode, aggregated together, are equivalent to V2G. A key determinant is therefore the number of vehicles participating and whether they are both connected to the electricity system and are able to be flexible. As an estimate of the relative size of markets, the table below shows some indicative volumes of particular services broadly based on current volumes and an expectation that, although service volumes will change, their relative size and how they compare with each other are likely to remain more stable.

	Despatch			Indicative service volumes			Despatch		
Service	Price Signal	Automatic	Instructed	Service equivalent Power (MW)	Service equivalent Power (MW)	Typical Frequency of call	Price Signal	Automatic	Instructed
Frequency Modulation		Yes		500	small	Continuas	small	small	small
Primary/ High Response		Yes		2,200	13.10	Assuming 5 events / week	2.20	0.013	4.8
Reserve (10 minutes)			Yes	3,000	1,000	Assuming 2 reserve call / day	3.00	1.00	365.0
Reserve (15 minutes)			Yes	3,000	1,500	Assuming 2 reserve call / day	3.00	1.50	547.5
Reserve (30 minutes)			Yes	3,000	3,000	Assuming 2 reserve call / day	3.00	3.00	1095.0
Time of Use / Arbitrage	Yes		Yes	10,000	2,500	Daily/ habitual	10.00	2.50	912.5
Gen Peak avoidance	Yes		Yes	1,000	2,000	Seasonal - 30dys year	1.00	2.00	730.0
Network congestion (e.g. avoiding evening peak)	Yes		Yes	3,000	3,000	Daily / habitual	2.20	3.00	1095.0

Table 1: Summary of value areas that EVs could access and indicative volumes of service

2.4 V2G market potential cont...

Note that the services Reserve (10 minutes), Reserve (15 minutes), Reserve (30 minutes) described in the table above are different ways that a reserve service could be defined. For example, 3 successive uses of Reserve (10 minutes) would provide an equivalent Reserve (30 minutes) service.

An important observation is that, during periods of time when many vehicles are charging, small variations in individual EV charging will deliver the service volumes needed and therefore there is less opportunity for V2G to differentiate from Smart/Variable Charging. Conversely, when there are fewer EVs charging, those EVs that are connected have a greater opportunity to differentiate V2G capability.

V2G can however differentiate from variable charging where they can reduce the underlying demand on the electricity system at peaks that would otherwise drive generation and network capacity investment.

2.4.3 Service requirements and alignment with EV charging

EVs present a tremendous and sizeable resource to provide flexibility resources however they also represent a significant impact.

Some costs could be substantial and unnecessary, for example mass responses to half hourly time of use price signals. Currently, the way the System Operator manages rapid changes in demand and uncertainty is by procuring additional reserve or imposing restrictions on rates of change. EV charging has the potential to introduce rapid changes in electricity demand if their charging behaviour is not co-ordinated to some degree and therefore affect the reserve volume requirement adversely.

Equally, service definitions could be designed to exploit EV capability as opposed to EV charging fitting around the services. For example, reserve service definitions and the way services are aggregated could be tailored to capitalise on the opportunity.

If the majority of charging is non-rapid (i.e. <7kW), the greatest opportunities for EVs to provide value to the electricity supply chain are overnight and during the working day when a large population of vehicles are stationary. 'Away from home' charging inducements and facilities will be essential in capitalising on this opportunity (cp. Figure 9 showing the available V2G capacity in various time slices in the baseline scenario). The calculated available capacity of V2G in each time slice, is presented in Figure 9. It is a result of the charging profile of the vehicles and the aggregate available capacity.

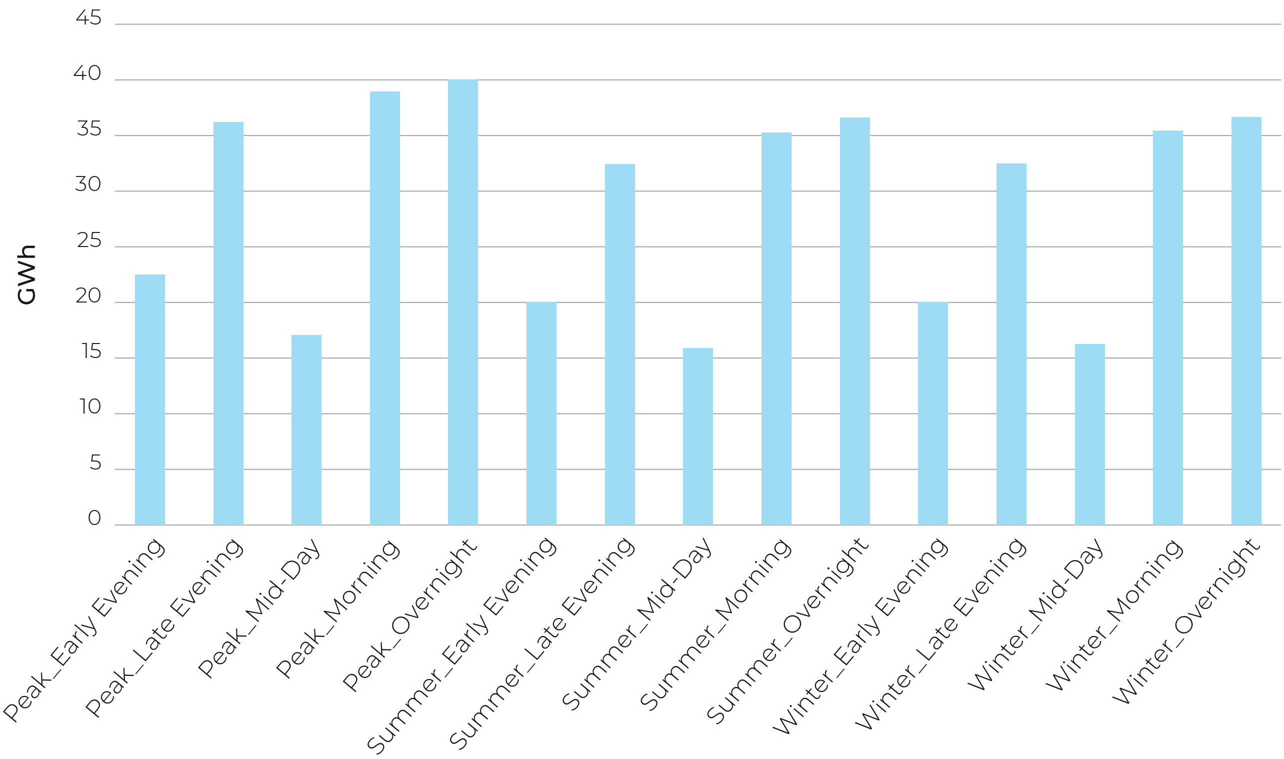


Figure 10: 2030 – Available V2G capacity in each time slice – Baseline scenario

2.4.4 Natural behaviour and inducements to adapt behaviour

The value obtained from EV storage capability and costs incurred by charging can be presented to EV users as a combination of benefits, charging costs, or reduced charging costs. It is unclear though, what the best way of combining the offerings to EV users is. Careful design of EV charging tariffs and levels of control will be key to achieve the right blend of incentives to deliver the EV amenity efficiently. Developing business models, ownership models and EV supply contracts terms will all play a role in building on and expanding knowledge in this area. A significant element of this is the way EV charging, and the services that they could offer, are aggregated and how information is exchanged between supply chain actors. Aggregation has multiple aspects including; market rules, roles and responsibilities, forecasting, despatching and paying for services.

2.4.5 Competition from other flexibility assets

Static storage, second life batteries and other flexible assets are likely to pursue the most attractive periods for flexibility service provision, which currently coincide with the times when the greatest proportion of EVs are mobile. Once investment in flexible assets has been made, there is likely to be competition to provide service at all times, which may depress service prices when EVs can contribute. It is likely, however, that local services, e.g. local network congestion management, will experience less competition and be confined to flexible assets at the residential level such as EVs and heat pumps.

2.5 Further work

During the course of WP1 whole energy system modelling and assessment, further areas were identified where more detailed analysis could derive additional insights. Findings and recommendations from WP1 were used in WP4. In summary these are:

- Use of more temporally detailed analysis of energy system operation (e.g. hourly resolution) over extended time periods to provide further insight in harnessing the flexibility that V2G can offer.
- Use of dynamic network modelling to investigate the energy flow between V2G and the network
- Sensitivity analysis around the level of intermittent generation and electrification of non-EV loads
- Sensitivity analysis around the available capacity of V2G, the impact of varying vehicle battery size on V2G opportunity
- Incorporating learnings about mainstream consumer EV usage and charging behaviour and the potential impact on V2G availability
- More granular analysis of fleet utilisation, vehicle battery sizes, battery degradation impacts and charging strategies to inform understanding of the opportunity for V2G amongst different types of fleet.
- Accounting for risk and uncertainty in key supply factors (e.g. short-term wind availability) and vehicle availability factors (e.g. due to journey variations)
- Enhanced modelling with data on V2G technology costs to inform business model feasibility assessments

Aggregation approaches and service definitions are critical in exploiting EV potential fully. For the former, understanding the risk reduction potential of pooling EV V2G storage capability during the day and year, at a national and local level will be invaluable. In the latter case, removing market barriers to Frequency Response and Reserve services could allow greater value to be extracted.

26

Near term revenues & target opportunities

3.1 Introduction

This chapter contains a summary of some of the work performed by Cenex in WP2 under the Innovate UK funded project V2G-Britain.

The work seeks to provide an evidence-based assessment of the realistic annual revenue of reasonably representative groups of people for V2G in the GB within the next five years.

The work also aimed to identify the early opportunities for V2G (in terms of both customers and markets) and derive revenue values for the most promising cases.

To this end, the work undertaken sought to:

- Use actual GB based data of EV charging and driving behaviour
- Provide some assessment of all possible revenue streams for V2G in GB
- Develop archetypal customers for V2G and provide a full assessment of the most promising cases
- Model the key archetypes against revenue streams using a half-hourly simulation of charging and discharging against market prices
- Obtain 'best case' revenue for the V2G proposition given varying sets of conditions

One of the challenges of evaluating the potential revenue for V2G in GB is that in order to derive accurate and justifiable results, the operation of the V2G unit within the given market needs to be modelled with a reasonably high granularity (e.g. half-hourly). This is because value in many of the relevant markets and services are highly time dependent. This, coupled with the fact that V2G provision using an EV is intermittent, means that detailed data sets giving EV availability and state of charge are required to do the best assessment. Every effort has been made to obtain the most suitable data sets, and appropriate modelling assumptions have been applied to support the analysis of the data.

3.2 EV Driver Archetypes

3.2.1 Introduction to EV Driver Archetypes

When developing a business model for a product or service, it is important to first consider two aspects:

1. The target customer(s).
2. The value proposition(s).

For development of existing products, it is possible to consider the existing customers, however where a product or service is entirely new or constitutes a significant change away from similar products, it is necessary to start from scratch and hypothesise on the likely customer groupings who would be interested in the product.

EV driver archetypes are fictional character groupings created to represent customers within a specific demographic. Typically, when developing an archetype, the following questions would be considered:

- Who are they?
- What do their lives look like?
- Where are they located?
- How do their behaviours impact your product?
- What are their aims, drivers and values?
- How and when do they make purchasing decisions?
- Where, when and how would they use the product?

By creating EV driver archetypes, it is then possible to analyse their behaviours in order to gain insight into the features or value propositions which would appeal to different groupings. It also enables us to make an initial assessment of the suitability of the archetype for the provision of services via V2G.

When thinking of archetypes, it is most intuitive to think of the EV drivers themselves. However, in the case of V2G it is the V2G charge point which is the asset that will provide services and earn revenue. How this revenue is then shared between various stakeholders is down to the business case and contractual arrangements. For this reason, each archetype is from the perspective of the charge point but making strong reference to the usage of the charge point by the EV driver. This approach enables us to include public charge points that may have multiple users or other complex arrangements.

Cenex has been actively involved in V2G research activities since 2013. During this time Cenex has gained experience of a range of potential use cases for V2G. This knowledge was extracted through a workshop and used to form a list of potential EV driver archetypes. These archetypes were then given further detail based on hypothesised characteristics which were then validated, where possible, using a mixture of Cenex and public data.

In total 35 EV driver archetypes were created under the categories of Residential and Commercial. An example of a Residential EV driver archetypes is given in Figure 10.

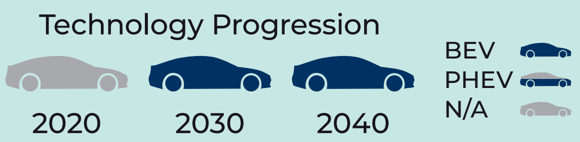
3.2.1 Introduction to EV Driver Archetypes cont...

The Retired Professional

The Retired Professional has a high-income background and is socially and environmentally conscious. They have PV on their home and are interested in the synergy with their midsized EV and off-street home V2G charger. The EV is used mostly for short or medium journeys during the day and is plugged in when not in use.

Key Information:

V2G Location:	Home
No. of EVs using charge point:	1
V2G Availability:	60-100%
Potential no. in the UK:	0-1k



Primary User	
Age Range:	over 60
Income Bracket:	Basic Rate
Employment Status:	Retired
Vehicle Ownership Type:	Owned
Battery Life Conservation:	High
Primary Motivation:	Environmental
Vehicle	
Battery Size:	Medium
Type of vehicle:	Midsize car

Usage	
Parking Pattern:	Predictable
Type of trips:	Short/Medium
%age of plugged-in time used for charging:	20-40%
Charging Location:	Mostly at this location
Location	
Building ownership type:	Owner
On-site renewables:	Yes
Parking Location:	Off-street

Figure 11: Residential Archetype Example

3.2.2 EV Driver Archetype Assessment

As mentioned previously, the archetypes were constructed from the perspective of the V2G unit. However, other important factors for the archetype are:

- Users of the charge point
- Type of vehicles plugging in
- Usage pattern of the charge point and EVs
- Location of the charge point

These factors are important since they determine the characteristics (such as timing and volume) of flexibility available for the charge point. In total, twenty-two key data points were used in the assessment of each archetype. Each factor was scored on a simple scale and the sum used as a measure of the applicability of the EV driver archetype for V2G. Whilst this score has no real absolute meaning, it enables the relative value of each archetype to be determined. Figure 11 shows this assessment of the home archetypes against the applicability to V2G.

Home Archetypes Assessment

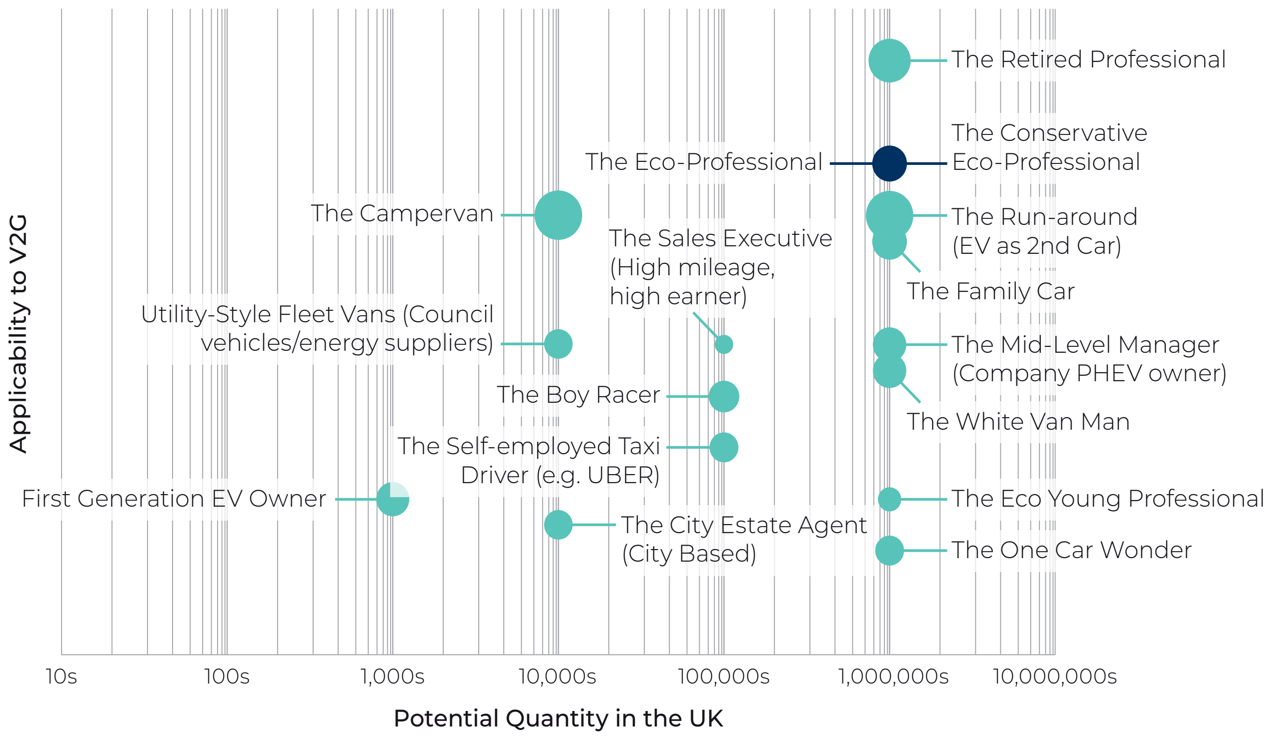


Figure 12: Assessment of residential archetypes. Bubble size represents the percentage of time EV plugged in and not charging.

From this analysis a short list of 'high value' EV driver archetypes was produced based on the following criteria:

- the potential quantity in GB by 2020,
- the applicability to V2G,
- the percentage of the day the EV is plugged in and not charging

These are presented in Table 2.

Archetype	Location of V2G charge point	Potential quantity of archetype in GB
Council fleet - Pool cars	Commercial	10k-100k
EV Car clubs	Commercial	10k-100k
Company car park	Commercial	>10M
The Retired Professional	Residential	1M-10M
The Eco-Professional	Residential	1M-10M
The Run-around (EV as 2nd Car)	Residential	1M-10M

Table 2: Archetypes Short Listed for Modelling

3.3 Revenue streams

3.3.1 Introduction to Types of Services V2G Can Provide

In order to provide flexibility services, V2G chargers can either be managed as stand-alone units or in local clusters. Distributed V2G units can also be aggregated to allow them to be managed and operated as groups for non-geographically sensitive energy services such as frequency response (see Figure 12 below).

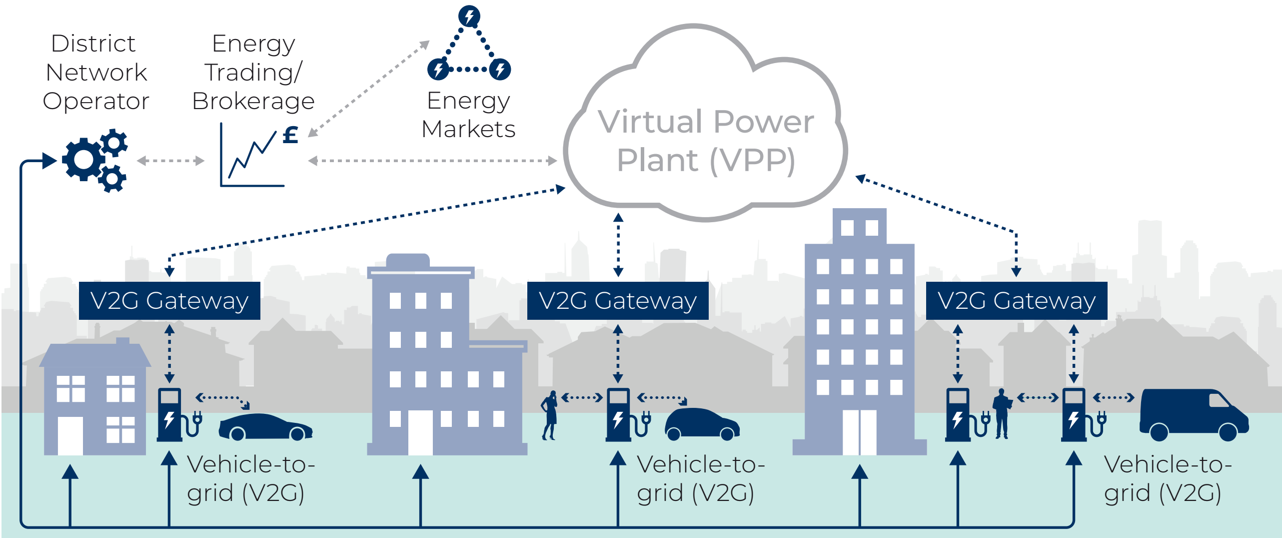


Figure 13: Aggregation of V2G units to trade electricity to energy markets via a VPP

V2G can therefore be used to provide a range of services at different levels in the energy system through demand shifting, exporting (discharging) or a combination of the two.

3.3.2 Core Services and Associated Financial Value

For the purposes of this analysis Cenex has identified 24 potential value streams for V2G. Each value stream was scored for suitability for V2G and ranked in order to provide an indication of the priority with which the service should be considered. The scoring criteria used for this assessment consisted of:

- Readiness for DSR.
- Technical Requirements.
- Minimum Capacity
- Service 'Stackability' (the ability to provide multiple services)
- Current Value
- Future Value

Each potential value stream was scored against the criteria. Figure 13 provides a graphical representation of the suitability for V2G of the top ten ranked revenue streams, versus a high-level estimation of the annual revenue.

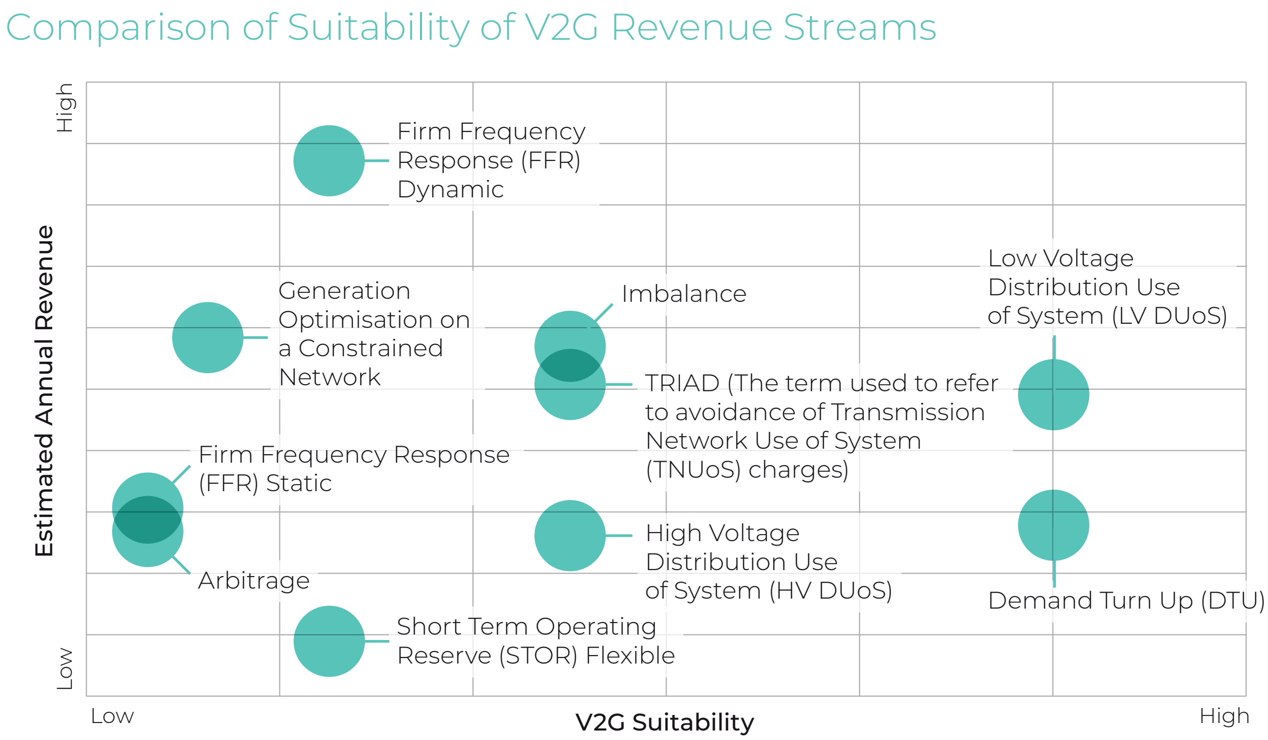


Figure 14: Comparison of Suitability of Top 10 V2G Revenue Streams

From this analysis, a short list of key revenue streams was produced that was taken forwards to the modelling work. DNO congestion management was excluded from the analysis since at the time very little information was available on this emerging market. It has however been subsequently included in WP3 and WP4. Further, given that our available data set for the customer archetypes are primarily residential focused, TRIAD avoidance was excluded, since residential customers are not currently exposed to this.

The short listed of key revenue streams are:

- Low Voltage (LV) and High Voltage (HV) Distribution Use of System (DUoS) charge avoidance
- Demand Turn Up (DTU) [1]
- Imbalance management
- FFR (both dynamic and static)
- Short Term Operating Reserve (STOR) – Flexible
- Energy price arbitrage

1 Despite the requirement for a negative reserve service, the volume procured and number of utilisations have fallen substantially since DTU was first procured in 2016. The offline dispatch process, long notice period for delivery and small volume procured were identified by National Grid ESO as the key barriers to increased utilisation of DTU in its current form: https://www.nationalgrideso.com/sites/eso/files/documents/EXT%20Demand%20Turn%20Up%202019.pdf

3.4 Modelling

The modelling for this work package has been performed using the Cenex REVOLVE model. REVOLVE is a perfect foresight optimisation model capable of simulating the charging/discharging behaviour of large numbers of EVs at half hourly granularity over a year.

Key Features:

- Simulates charging/discharging of up to a few hundred EVs
- Customisable constraints on max charging/discharging power to allow modelling of specific or generic V2G units
- Customisable constraints on max/min storage capacity of EVs to allow modelling of specific or generic vehicles
- Constraints on EV availability (plug-in times) and requirement to make journeys (energy demand)
- Modelling of:
    - charging/discharging losses
    - half-hourly varying import and export tariffs
    - flexibility of charging/discharging for the provision of grid services
- Simulation of local PV generation
- Optimises EV charging/discharging against behind-the-meter value streams and grid services
- Customisable warranty constraint modelling through optional limiting of maximum kWh of V2G provision per vehicle per day
- Evaluation of the impact of battery degradation costs on V2G revenue streams

Key data inputs for the REVOLVE model are:

- EV journey demand data sets
- EV availability data sets (a flag of plug-in status of each EV for each half hour)
- Half hourly demand data sets (for each charge point)
- Half hourly import and export tariff prices
- Grid service parameters and prices
- EV and charge point energy and power capacities and efficiencies

The model optimises the charging/discharging behaviour of individual EVs on a minimum cost basis using the import and export tariffs available to the EV. Whilst the model covers an entire year, it does this by optimising weekly blocks one at a time. Each EV in the model has an associated journey demand and plug-in availability data set for the year. It also includes the local electricity demand for the site or building(s) the charge point is connected to. The charge point is assumed to be behind-the-meter and so, by discharging the EV, the local demand can be offset.

The charge points in the model can also be aggregated up and offered to provide grid services. The model stacks the available flexibility inherent in the charge points to build up the grid service product window requirements. To provide a grid service, a minimum capacity (in MW) must be held in either an upwards or downwards (or both) direction, for the specified grid service periods. During the entire service periods, the model must also hold sufficient stored energy/demand reduction (or battery headroom) to meet a minimum length of call of the grid service product. Note that whilst this headroom/footroom is held, the model does not currently simulate the actual calls due to the additional modelling complication this adds.

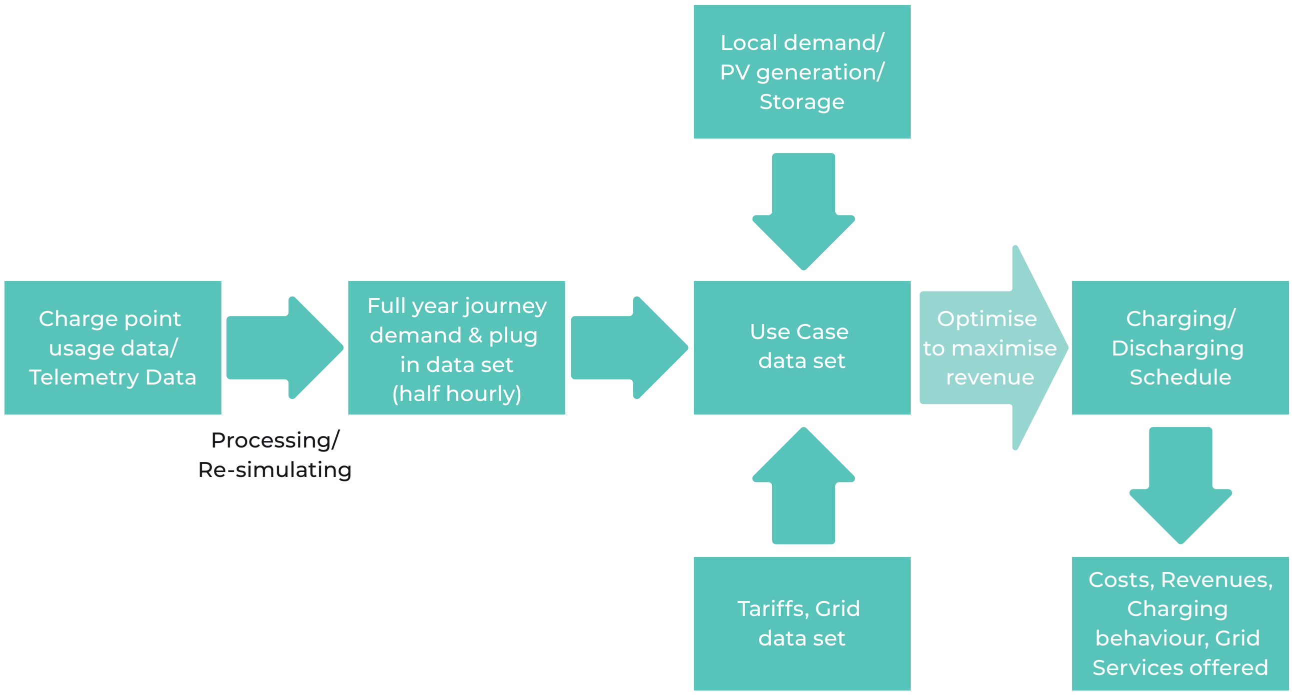


Figure 15: Cenex REVOLVE model diagram

Because the model is a perfect foresight model, it provides an upper bound on the revenue that can be earned through the V2G options modelled. In reality there will be deteriorations in the value through EV availability forecasting error.

In order to quantify the value provided by V2G, the model first performs an Unmanaged run. In this, all EVs charge up to full as soon as they are plugged in. This run is used to create an energy cost baseline. Subsequently, an Optimised run is performed. In this run the charging and discharging behaviour is optimised on the basis of minimum cost.

3.5 Use Cases

This section covers the different Use Cases that were used to define the model runs to be carried out. Each Use Case is made up of a combination of the following:

- Charge point data set (corresponding to a customer archetype)
- Local energy demand
- EV parameters
- Charge point parameters
- Import and export tariffs
- Grid services products and prices

3.5.1 Archetype Data Selection

Having identified the most promising archetypes, these were then matched to existing EV and charge point data sets. Data was obtained from the Electric Nation trial[2], the Ultra-Low Carbon Vehicle Demonstrator (ULCVD) (an Innovate UK trial capturing charging and journey data for EVs between 2011 and 2013) and from the 'Ebbs and Flows of the Energy System' (EFES) demonstrator (an early V2G demonstrator project).

After matching the data sets to archetypes, the data was cleaned and filtered. Charge point data sets were limited to only those with sufficient data quantity and quality. This led to such a small number of data set for each archetypal customer, that in order to produce a sufficient level of diversity in the portfolio (required for offering grid services) the data sets need to be combined into a single Combined Archetype.

The make-up of this resulting combined archetype is shown in the following chart.

Combined Archetype: 60 Charge Points

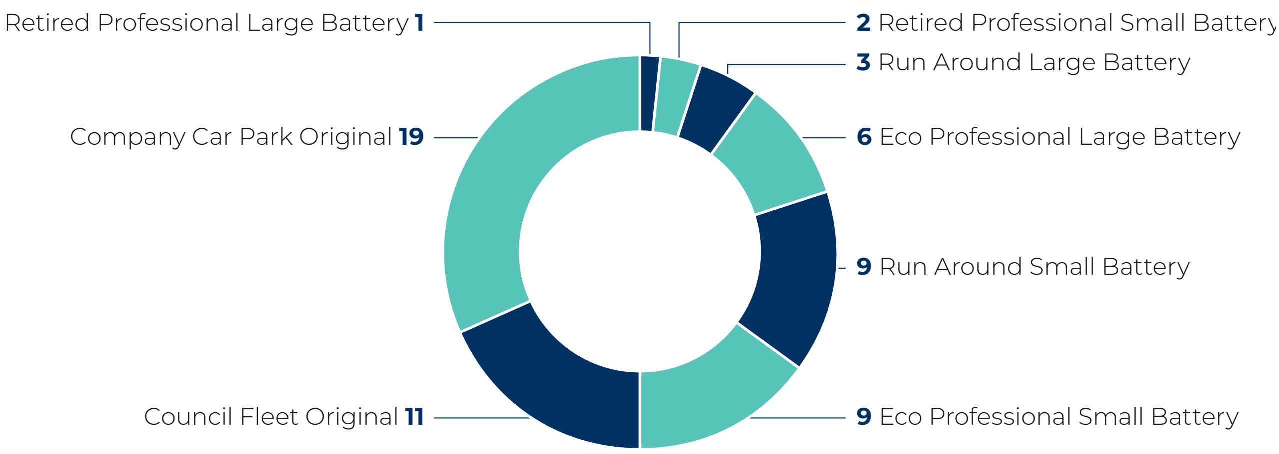


Figure 16: Components of Combined Archetype

2 www.electricnation.org.uk

3.6 Use Case evaluation

Several different use case configurations were run through the model and a few are presented in this section. Note that the modelling is based on current market arrangements of services. However, these are changing (i.e. National Grid ESO's reform of flexibility services as set out in the ESO's Forward Plans[3], changes to Balancing Mechanism access and connection regulation by Ofgem, as well as the emergence of DNO flexibility markets). These changes might lead to different assessments in the future.

3.6.1 Base Case Run

The base case run consisted of the combined archetype, FFR, STOR and DTU grid services and the Economy 7 tariff. Figure 16 shows the average annual cost and savings per charge point for Smart Charging and V2G. This is calculated from the results of the Unmanaged, Smart and V2G model runs. The import cost (red) in the figure represents the average annual energy cost across the 60 customers in the archetype. This includes the energy used in the building and for charging the EV. The import savings (black) show incremental savings made by employing first the Smart uni-directional charger and then the bi-directional V2G charger. The cost of transitioning from a single rate tariff (which is cheapest for most customers) to an E7 tariff (necessary for smart charging optimisation) is also shown. Savings from the Smart Charger are due to delaying charging of the EV to off-peak periods. It should be noted that in this case, all these savings could be realised by a simple timer charging solution. The additional import savings in the V2G case are due to a small amount of discharge from the EV to offset the building demand during peak rate periods. The value is small due to the combination of a relatively small (7p) tariff spread, round trip efficiency losses and the limitations from coincidence of EV availability and building demand. The chart shows that in this use case Smart charging can capture around 80% of the savings compared to V2G.

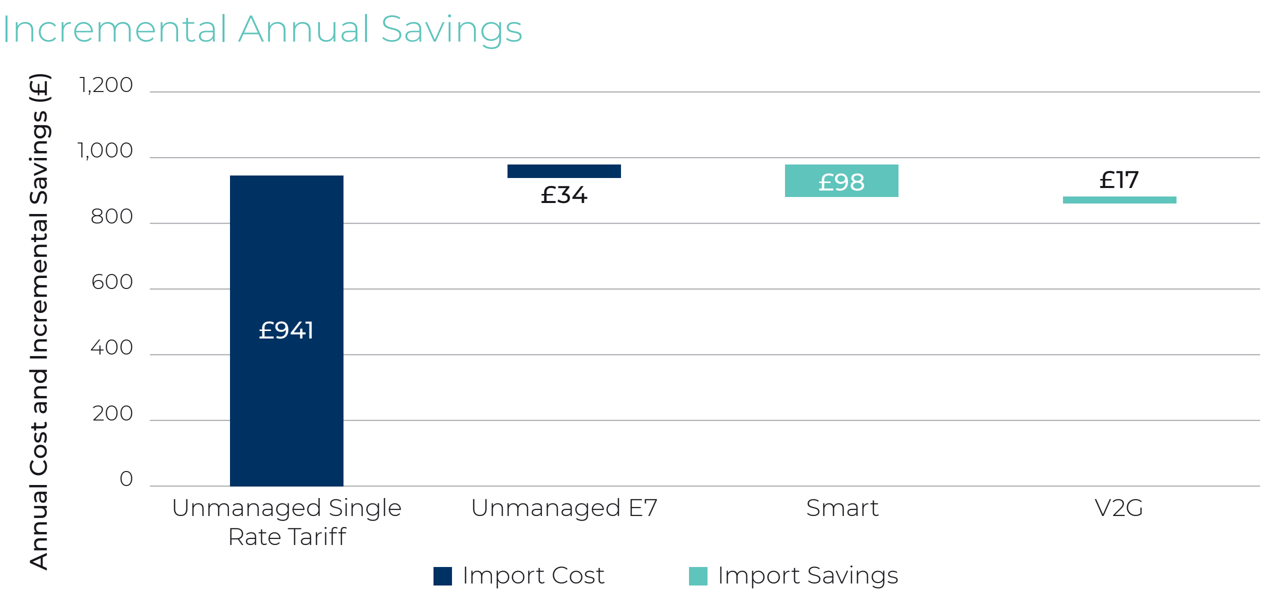


Figure 17: Base case incremental savings without grid services

3 https://www.nationalgrideso.com/news/our-forward-plan-2021

3.6.1 Base Case Run cont...

Once we include grid services, the picture changes somewhat. Results of the corresponding model runs, with grid services included, are given in Figure 17. This shows similar import savings to the previous case, however V2G can capture much more value in grid services than Smart Charging. This is due to the specifications of the individual services modelled. In this Use Case Smart charging is only able to capture 40% of the revenue that V2G can (netting off the cost of moving to an E7 tariff from any savings made).

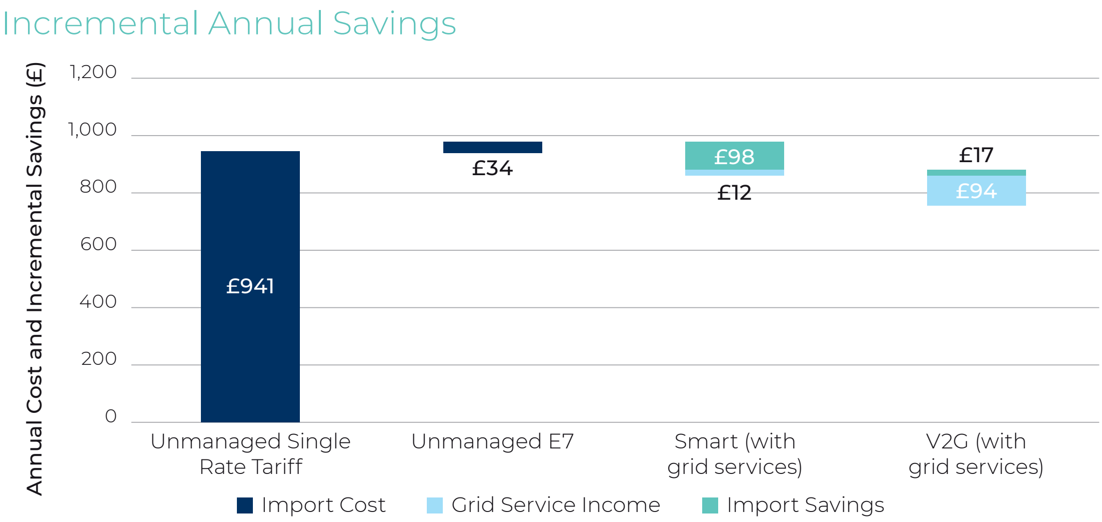


Figure 18: Base case incremental savings with grid services

It is useful to look in more detail at what grid services have been offered by both the Smart and V2G runs. The following two figures provide a breakdown of the revenue earnt in both runs. Note that the figures show the total (not incremental) revenue earned.

The make-up of this resulting combined archetype is shown in the following chart

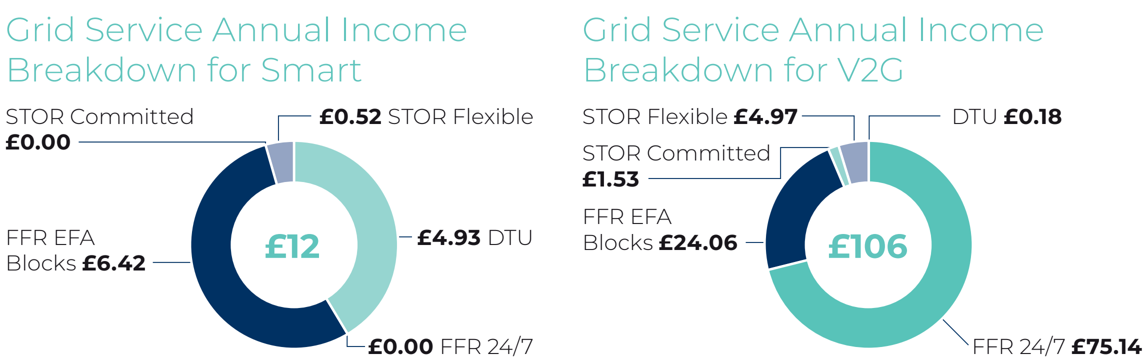


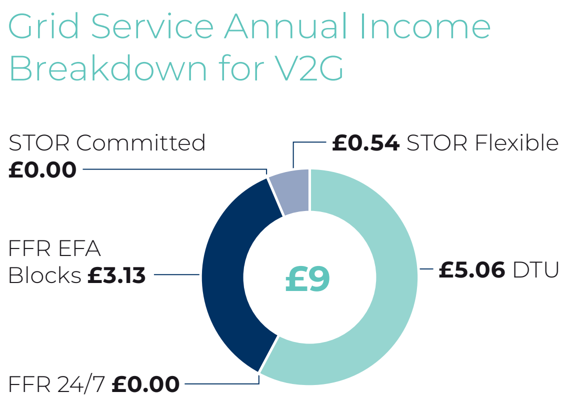
Figure 19: Grid service revenue breakdown Smart (left) and V2G (right)

3.6.2 Sensitivity 1: Low FFR Price Scenario

From the base case runs it was clear that FFR was the most lucrative market for V2G. However, the value of FFR has been in steady decline in recent years and the inclusion of V2G or other flexibility services in large volumes would be likely to further erode the value of the service. Therefore, a sensitivity analysis was performed where the FFR prices were halved, giving the sensitivity price of £5/MW/h for 24/7 service and £4/MW/h for EFA blocks.

In this run import savings are virtually unchanged, however, the grid service income is significantly reduced. For V2G the total grid services income is £59 compared to £106 in the Base Case. So, a halving of the FFR price results in an almost halving of the grid services revenue for V2G.

From the two figures above, we can see the FFR remains to be an important component of the revenue even at these lower prices. Although the transition to other grid services has started (notably with STOR in the V2G case) the point where other grid services become the more lucrative option has not yet been reached, suggesting significant risk in potential revenue earned from grid services.



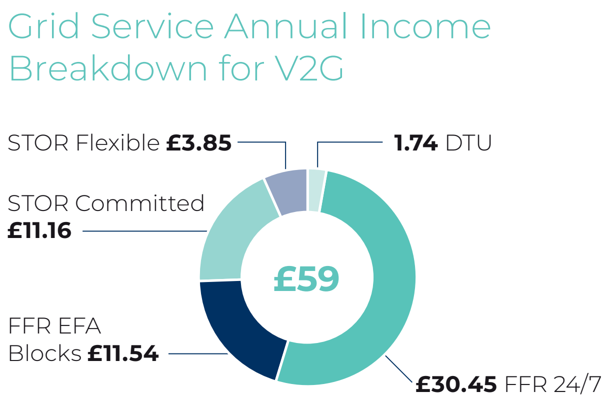


Figure 20: Grid service breakdown Low FFR price: Smart (left) and V2G (right)

3.6.3 Sensitivity 4: High Plug-in Rate Scenario

One limitation of the Combined Archetype that has been used in all the model runs so far is that it has an average plug-in rate of around 30%. . It is reasonable to assume that if encouraged, V2G users could achieve much higher plug in rates. Whilst the data from the EFES trial (that matched the Run-Around archetype) was for only one car, it had a very high plug-in rate of 75%. Because of the quality of the data set, with plug-in events on virtually every day, the simulation module in the model was able to be used effectively to simulate clones of the data set that exhibited similar statistical properties in terms of journey timings and durations.

3.6.3 Sensitivity 4: High Plug-in Rate Scenario cont...

The value of this simulated data set is that it gives us sufficient diversity to offer into grid services and it provides a 'best case' example from a V2G perspective of a vehicle that is regularly plugged in and available.

Figure 20 shows the incremental savings for both smart and V2G. Smart charging can achieve less import savings than in the Base Case. This is perhaps due to a much lower mean annual journey demand for the EV (637kWh compared to 1,842kWh in the Base Case). Whereas V2G can gain additional savings. V2G is also able to capture a total of £414 in annual revenue from grid services (almost all of which comes from FFR). This is around four times the equivalent value from the Base Case.

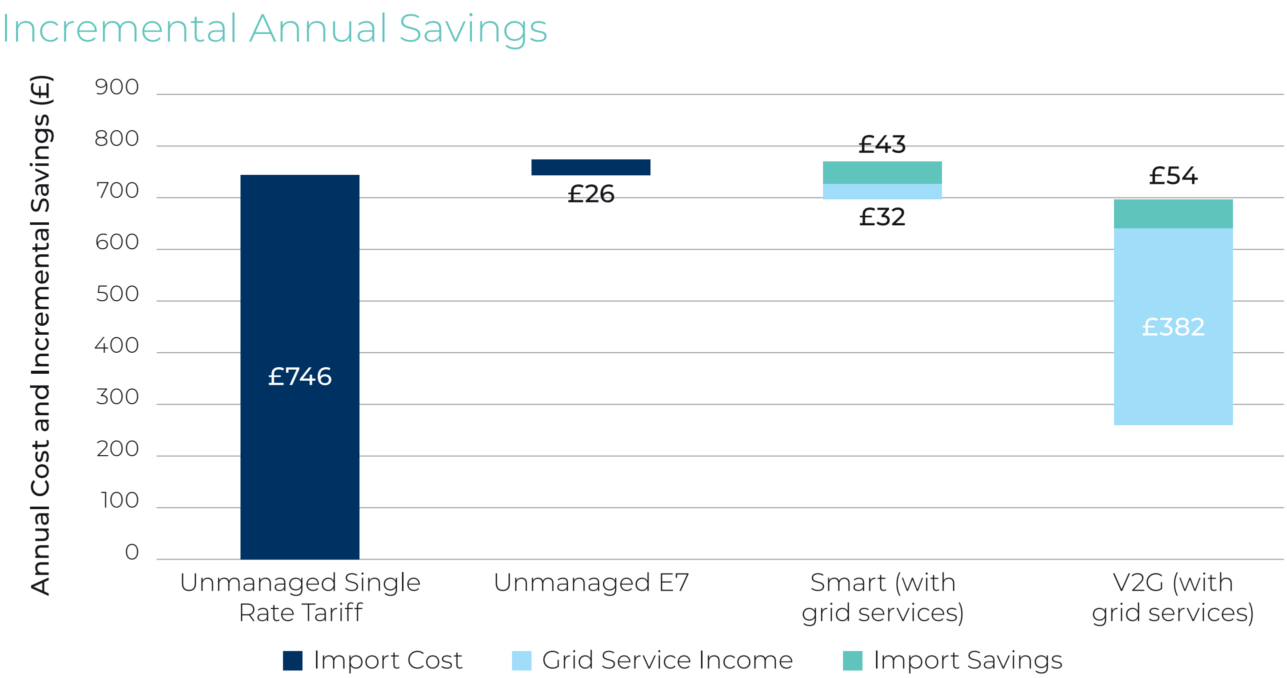


Figure 21: High Plug-in rate incremental savings with grid services

The V2G demonstration projects that Cenex has been involved with suggest that these users plug the vehicle in more regularly than conventionally charged EVs. Indeed, this high plug-in rate data set is based on a V2G demonstration. Whilst it is clear that these very early adopters are unlikely to be representative of most users of a wider V2G uptake, it does show that some change in plug-in behaviour is likely. This high plug-in rate scenario shows the potential of V2G if this behaviour change takes hold.

3.7 What is the potential impact of V2G

Out of the cases run through the model, the one that had the most potential for V2G was the high plug-in rate case, including grid services. This was able to capture an annual value of £436 under current market conditions. The high plug-in rate data sets matched the “Run-around” archetype. Assuming there are one million of these archetypal customers in GB, then this archetype alone has the potential to generate an annual revenue of £436m through the use of V2G (excluding any related costs).

Revenues for the Combined Archetype were lower. However, it should be noted that this was based on current plug-in behaviour with standard charge points. With V2G charge points users would likely plug in more regularly, and so it could be expected that revenues across most archetypes would increase, but not exceed that of the high plug-in rate case.

Due to limitations in the available data there was little value in making estimates of the total value available across all the archetypes. However, it is possible to quantify the impact which the combined archetype would have on the FFR market.

From our Combined Archetype of 60 charge points we can see that they provided on average 0.05MW of 24/7 FFR. Assuming that National Grid ESO had a dynamic response requirement of 650MW, it would take 780,000 charge points to fulfil this.

3.7.1 Interpretation of Results

There are of course limitations to any assumptions made in modelling and these will cause differences between the values quoted and what is attainable in the real world.

Differing plugging in behaviour will be a key driver in the differences. The behaviour of the users of EVs in the data used, appeared primarily to be plugging in on a need basis. i.e. they plugged in to charge the EV for a journey, rather than always charge to full after every journey. This resulted in a low plug-in rate. Our sensitivities showed that plug-in rate is a key driver for value for V2G, and results in the real world will depend a lot on actual plug-in behaviour of EV users.

The model applied used a perfect foresight approach. This means it could see in advance exactly when EVs would be plugged in, how long the journeys would be and what the prices of energy and grid services would be. In reality, all these things would need to be forecast in order to take a similar approach. The errors in such a forecast would result in a reduction in captured value relative to what was modelled here. This error will be different for the different components. For example, most residential electricity tariffs are known accurately for months ahead. However, imbalance prices are never known in advance and are hard to forecast.
User behaviour also varies in how hard it is to forecast depending on the type of user. There is significant uncertainty as to how much lower the value captured by V2G in the real world would be when compared with the values presented in this report, but the results can be used to give a strong indication of the scale of the value and the service combinations to target to maximise this value.

3.7.1 Interpretation of Results cont...

In modelling the use of the EVs for V2G it was assumed that there was no inherent cost associated with degrading the battery through discharging to the grid. It is clear that this is not the case in reality. However, the consideration of degradation effects and costs need a very careful treatment, since the effect is not a simple one. This is potentially a risk to the value of V2G services, as demonstrated by this example. Using assumptions by Cenex of a battery lasting 2,000 full cycles before incurring a replacement cost of 179£/kWh we assume a cost of 8.95p per kWh discharge. If this cost were applied to the model runs that used the Economy 7 tariff, then any gains that V2G made by charging during the cheap rate period in order to discharge at peak rate (offsetting local demand) would be negated. This is because the Economy 7 price spread is only 7p, so the revenue earned would be less than the cost of battery degradation. This example is imperfect, yet it demonstrates the need for the effect of V2G on battery degradation to be clearly understood and quantified. A wide range of impacts of V2G on the vehicle battery has been suggested in recent studies, from a significant acceleration of degradation to a reduction of degradation[4].

All the runs performed in the modelling were with just 60 charge points. Whilst this offers an acceptable level of diversity, results would improve with a larger portfolio. The greater the diversity, the higher the revenue will be from grid services offered by the portfolio. This effect hasn't been quantified in this work, however it will be a lesser effect than that of increasing the plug-in rates.

The Combined Archetype used represents a combination of both Commercial and Residential archetypes. There is likely value in combining these in a portfolio, as the plug-in times could be complementary, helping to provide a greater proportion of time with at least some vehicles plugged in. A portfolio made up of just Commercial or Residential is likely to earn lower revenues.

3.7.2 Stackability

Whilst not discussed in depth in this report, the stackability of the different revenue streams was considered during the revenue stream selection process. Hence the final set of revenue streams used are amenable to stacking. As a result of the modelling approach used, stacking wherever possible is inherent in the process. For example, all the grid services included (FFR, STOR, DTU) can be stacked provided the same capacity is not used to provide more than one of the services at the same time. The results of the model runs also suggest that these grid services stack well with import savings (as adding the option to provide grid services barely reduces import savings). For some customers archetypes there are additional revenue streams that can be stacked with revenues stated in this report. One example of this is TRIAD avoidance. However, this opportunity only exists for larger commercial (not residential) customers and due to regulation changes the revenues available are in steep decline.

4 Uddin et al., 2018, The viability of vehicle-to-grid operations from a battery technology and policy perspective

3.8 Conclusions

The aims of this chapter can be summarised by three key questions:

1. Is there additional value which can be achieved by V2G compared to Smart charging?
2. What are the key factors which influence this value?
3. What are the key services which V2G would need to provide to achieve maximum economic value?

This chapter indicates that there is added economic value which can be accessed by using V2G chargers compared to Smart Charging. However, it is also clear that the scale of this value is extremely variable and is impacted by a wide range of factors relating to the usage of the charge point and the behaviours of the user(s). In the case of a high plug-in rate archetype (75%) a 7kW V2G charger could be capable of achieving annual revenues of around £436 above Smart Charging.

By assessing the different EV driver archetypes and revenue streams we can see that one of the most influential factors impacting achievable economic value is the plug-in rate, especially when considering the provision of grid services such as frequency response. However, the relationship is not linear, as demonstrated by the 'high plug-in' case where archetypes with 75% plug-in availability attracted around 4 times the revenue of those with 30% plug-in availability. This is a key result, given that the average plug-in rate for the data sets used in this study was just below 30%. This represents typical plug-in behaviour of current EV drivers who are not incentivised to plug-in beyond the immediate benefit of charging the vehicle. It is therefore suggested that providing additional incentives to plug in would likely increase this value significantly. This was supported by data from existing V2G trials.

Much of the current value of V2G comes from provision of grid services and in particular FFR, while innovative half-hourly tariff modelled was also found to offer little additional opportunity for saving with V2G when compared to the existing E7 tariffs. However, there is significant risk to grid service revenue for V2G, with at least half the revenue at risk from falling FFR prices. After FFR, additional grid services offer diminishing returns due not only to lower prices, but also because they are only required during certain windows throughout the year.

If grid services are excluded, then Smart Charging can capture 80% of the value of V2G for low plug-in scenarios, or 24% for high plug-in cases. Therefore, if V2G incurs much cost additional to that of Smart Charging then it would likely counteract the value added by V2G. When including grid services, Smart Charging captures 40% of the total value of V2G for low plug-in scenarios, or merely 10% for high plug-in cases.

44

Business models and value chains

4.1 Introduction

Since the launch of the first generation Nissan Leaf in 2010, Nissan has been studying the impact of deploying Battery Electric Vehicles (BEVs) on electricity supply networks.

This WP3 report aims to inform stakeholders of how the application of smart integrated BEV charging technologies (Vehicle to Grid "V2G" or Vehicle Grid Integration "VGI"), can create sustainable business models that can:

- Provide services that enable greater penetration of renewable energy into electricity grids
- Accelerate the adoption of zero emission BEVs by delivering net benefits to customers

Nissan have sold c.28,000 zero emission Leaf in the UK between 2010-18, equivalent to c.825MWh of battery storage capacity. As manufacturers will have to deploy BEVs to meet stricter CAFE targets, by 2025 BEVs could add some 8GWh[5] of battery storage capacity to GB every year. Integrating BEVs into the energy system in a flexible way could bring holistic benefits to energy users, increasing the efficiency of renewable generation and reduce the cost of owning a BEV.

4.2 Objectives

This chapter covers the work undertaken during the FY'18 V2GB Feasibility Study in WP 3. This work package had the following objectives:

- Develop a customer centric value propositions for V2G services
- Complete business models using the Business Model Canvas tool
  - To reveal the best possible business models for V2G services
  - To identify which stakeholder is best placed to perform the function of the aggregator.
- Conduct quantified analysis

5 8GWh is over 20% of the 35GWh of storage currently serving the GB system.
The requirement for storage is expected to increase in future years in proportion to an expected increase in renewable generation capacity.

4.3 Value propositions arising from V2G

Much like a grid connected stationary battery storage, a BEV that can be charged and discharged to and from an electricity network can act as either a load or a supply. Aggregating a number of residential BEVs and coordinating their cumulative charging behaviour is believed to deliver benefits for V2G customers. It is important to clarify that when terms such as "the customer" are used in this chapter, this term is referring to the company or individual who is willing to pay for electricity flexibility services and not necessarily the owner or operator of a BEV or the consumer of electricity.

The Business Model Canvas (BMC) method which was used to identify and test exploratory business models aided this clarification: The BEV users are key partners in the provision of these services; they are required to offer the use of their resources in a flexible manner and as a result will likely require some form of incentive to do so.

4.4 The customers

Through developing an intimate understanding of each customer segment, each stakeholder's long term goals and ambitions were identified. Through bilateral stakeholder discussions it was possible to reveal the benefits that could be delivered when providing targeted services to customers.

The following shortlist of businesses were identified as the most likely candidates to benefit from flexible V2G services provided by an aggregation company:

Proposed Customer	Summary of Value Proposition to Customer
Transmission System Operator (System Operator/ESO)	**Value Proposition 1** (VP.1): Frequency response and other ancillary services (FFR, STOR, DTU)
Distribution Network Operator (DNO)	**Value Proposition 2** (VP.2): Deferral services to avoid the cost of reinforcement
Electricity Retailer/ Supplier	**Value Proposition 3** (VP.3): Optimise gains from volatile imbalance prices
Residential Solar Generator	**Value Proposition 4** (VP.4): Optimise Home Solar PV generation and self-consumption

Table 3: Value Propositions

4.5 Transaction channels

Aggregators can supply Demand Side Flexibility (DSF) services by changing the charging behaviour of a given group of BEVs. How this behaviour can be modified relies greatly on the hardware used to connect to each BEV, essentially what functionality the BEV charge point has.

Various BEV charging management devices are compatible with acting as a channel for providing dispatchable V2G services. These channels* are critically important, as they not only link the user of the BEV through the charging experience to the service provider, they also dictate the level of functionality a service can offer and this can affect the revenues that can be earned.

The channels can be categorised into four distinct types:

	Type	Supply	Variation in Method of Control
Uni-Directional Smart Charging	Level 1	7kW AC	Behaves in an on/ off binary manner. Turning on or off in response to signals or a preprogramed timer
	Level 2	7kW AC	Incrementally changes the rate of electricity supply to the BEV, ramping up and down
	Level 3	7kW AC	The BEV itself in response to a signal can incrementally reduce or increase the rate of charge requested
Bi-Directional Smart Charging	Level 4	10kW DC	In addition to smart functionality the charge point is given permission to release energy stored in an EV's battery to supply electricity

Table 4: Transaction channels

It is important to understand the functional benefits and disadvantages of each charger type as some chargers have a greater capacity to supply services whilst carrying very different cost premiums.

Type	Benefits	Disadvantages
Level 1	• Less high tech hardware required: Longer warranties may be available • Conveniently allows for simple tariff arbitrage	• Durability of rapid switching is a concern so considered unsuitable for FFR • Third party application to confirm availability • Flexibility is only available during charging • Cannot access vehicle data from the vehicle
Level 2	• By running at 50% of rated power capacity this charger can achieve an operating headroom that allows for an increase and decrease of load taken	• Third party application to confirm availability • Does not communicate with the vehicle • Flexibility is only available during charging • Cannot access vehicle data from the vehicle
Level 3	• No additional charging hardware required, any "dumb" charger is sufficient • A third party app is not necessary, the user interface can be onboard the vehicle • Can collect user behaviour data	• Requires BEV manufacturer collaboration • Requires BEV with on-board connectivity • Flexibility is only available during charging
Level 4	• Vehicle can act as a distributed generator • Communication is direct to the vehicle • Can Collect user behaviour data • As the vehicle can charge and partially discharge multiple times each session, flexibility is available for longer periods • DC chargers are available with higher power capacity	• Requires compatible DC charging standard (such as CHAdeMO) and manufacturer collaboration • Battery is at risk of accelerated degradation when acting as a generator • Most expensive option

Table 5: Advantages and disadvantages of transaction channels

4.6 Costs of different charger types

In this study the four variant chargers identified were costed on a relative basis to the installed cost of a non-smart "Dumb" 7kW AC residential charger (estimated to cost £500).

The costs below are indicative of the future (c.2023) premium that would have to be paid above the price of the benchmark charger; it reflects the cost of a single new residential installation rather than an upgrade to an existing connection or new public/commercial connection. As of today the actual premiums paid for prototype and early market smart/ V2G charging hardware are significantly higher than those used in this report; however, in an effort to reveal future potential of the business cases, premiums indicative of a more mature market were used.

4.6 Costs of different charger types cont..

Type	Power (kW)	Current	Smart	Bidirectional	Total premium to install Smart charger above the cost of a "Dumb" charger	Premium depreciated over a useful 5 Year period	Premium depreciated over a useful 10 Year period (Straight Line Method)
Level 1	7	AC	★	-	+£100	+£20	+£10
Level 2	7	AC	★	-	+£400	+£80	+£40
Level 3	7	AC	★	-	+£150	+£30	+£15
Level 4	10	DC	★	★	+£3,000	+£600	+£300

Table 6: Cost of different charger types

The depreciation rate is based on a 5 and 10 year straight line depreciation; in this report the 10 year model will be used. A 0% Interest rate has been applied and a 0% replacement/ warranty rate has been considered, in today's embryonic market there is little evidence of warranty periods of this length. This report therefore presents an illustratively optimistic annualisation of the cost premium.

All other costs relating to the provision, installation and maintenance of the charging hardware can be considered to be covered by the premium paid above the cost of the benchmark. The exception to this, is the fee paid for the existence of an aggregation service which is considered separately.

4.7 Aggregation costs

Aggregation services are commonly tendered on the basis of the aggregator taking a share of revenues generated by the demand side flexibility services offered to the aggregator's customers. The following assumptions were applies to aggregator cost modelling:

- 20% share of revenues from grid services
- Minimum return from services revenues of £30 per BEV per year to enter market. Thus service revenues need to exceed £150 per BEV per year (£150 x 20% = £30)
- The aggregator takes no share of import savings. Due to the nature of import savings the aggregator is not required, it may be, that by their own efficiency and activity, the aggregators start to generate additional income from this source but at this point no share of import savings has been allocated for aggregators.

These cost are then compared against potential revenues and savings for each of the suggested value propositions.

4.8 Revenues and savings

Work carried out by Cenex in support of Work Package 2 (WP2) of the V2GB study has helped to quantify both the revenues from services and the potential import savings arising from the optimisation of charging behaviour. Element Energy and Nissan have collaborated with Western Power Distribution (WPD) to estimate potential revenues from DNO services.

4.8.1 Revenues and Savings: VP1 Services to the System Operator

VP1 presents a traditional approach to offering balancing services, by bidding into pre-existing markets provided by the System Operator. Typically a battery asset can generate revenues by providing demand management services, as WP2 have shown there are several key high value services which can be delivered, these include: Dynamic and Non-dynamic Frequency Response (FFR), Short Term Operating Reserve (STOR) and Demand Turn-Up (DTU). A BEV that is charging can also behave in much the same way, turning demand up or down at a customer's request. BEVs connected via bidirectional chargers have the added advantage of being able to actively provide services before the vehicle begins charging or after it has finished so long as they are plugged in, thus increasing both the utilisation of the BEV/ charge point as services can be offered over a much longer period.

WP2 modelling intrinsically favoured offering the highest value services like FFR, with revenues generated being proportionate to the time the charge point is active. This led to the examination of two specific scenarios an average case (Base Case) and a best case (high plug in rate sensitivity):

1.0 Base Case: **Average Plug-In Rate**	**FFR 24/7 price: £5/MW/h** **FFR EFA blocks price: £4/MW/h**	**Plugged in availability:** **6 hours per day**

Due to the reliance of this value proposition on generating revenues from FFR the price (£) per MW/h has been set to reflect a future expected value for FFR. Revenues reflect the mean amongst a population of users as set out in WP2.

1.1 Sensitivity: **High Plug in Rate**	**FFR 24/7: £5/MW/h** **EFA EFA: £4/MW/h**	**Plugged in availability:** **18 hours per day**

This sensitivity looks to examine the potential to generate revenues if an extreme plug in rate can be guaranteed, therefore maximising revenue generation specifically when providing services utilising bidirectional chargers. Using a vehicle's battery can increase the risk of accelerated battery degradation, strict monitoring and management of the energy throughput in all use cases (including driving) are required.

4.8.2 Revenues and Savings: VP2 Services to a DNO

VP2 explores a relatively new business opportunity in the local flexibility services market. Distribution Network Operators (DNOs) face the biggest impact of GB's energy transition; without countermeasures, increasing network loads from EVs and heat pumps and distributed energy generation creating regional constraints, will result in considerable new infrastructure investments running into multiple millions of pounds (£GBP). DNOs more exposed to these constraints are taking progressive early steps to become Distribution System Operators (DNO); becoming customers of flexible load service providers[6].

If a fleet of BEVs exist in a region whose network is approaching a network constraint, then useful services like demand deferral or local generation can be purchased to counteract any urgency for upgrading the network. However if no local constraint exists, there will be no opportunity to access these revenues at all so opportunities are restricted by the circumstances in the local distribution network. The large majority of local substations are not under constraints and have sufficient headroom capacity (according to WPD's Network Capacity Map).

In these scenarios the BEV is called to defer its charging or to provide distributed generation to avoid peak constraints. Constraints generally occur during winter months, but how many times each month a DNO might utilise flexibility services is still unknown. A sensitivity has been modelled to examine the effect of a high utilisation of BEVs to provide the service.

2.0 Base Case: Average Call Rate — **WPD's Secure Service**

It is assumed that BEVs are utilised at the average utilisation rate of the service. BEVs cannot provide all of the services requirement (in MW). If the service is utilised on only a few days but at high power capacity only a small share of the overall utilisation of the service will be provided by the BEVs.

2.1 Sensitivity: High Call Rate — **WPD's Secure Service**

In this sensitivity to the Base Case, the DNO is anticipated to utilise the service during more regular weekly events but at relatively low power capacities and call upon BEVs preferentially in these periods. Providing services more frequently allows an aggregated set of BEVs to maximise the revenue they can generate.

This analysis looked at publicly available guidance data provided by Wester Power Distribution as part of their exploration into purchasing DNO flexibility services. The services revenues currently include an arming/ availability payment as well as an additional utilisation payment, these are both included in the estimated values.

6 http://www.energynetworks.org/electricity/futures/open-networks-project/

4.8.3 Revenues and Savings: VP3 Imbalance Optimisation

VP3 attempts to maximise returns through optimising a supplier's position in the balancing market. This case requires advanced forecasting methods and having near perfect foresight of imbalance pricing - an exceptional level of aggregation not evident today. Despite being an interesting orthogonal revenue stream for aggregators and suppliers, the spread of system pricing was insufficient to illustrate any competitive revenues. Further dedicated study is required to seek more credible revenues.

4.8.4 Revenues and Savings: VP4 Home PV Optimisation

The charge point selectively chooses to optimise the charging of the BEV instead of exporting electricity back to the grid. In this case the consumer is able to make additional import savings, beyond those considered for other cases. In this scenario it is assumed that the solar panels are a pre-existing asset and that the device is not included as an additional cost to the model.

4.8.5 Import Savings

Import savings have been estimated based on the optimisation of the price paid for imported electricity. This was calculated in WP2 as being the difference between a flat rate tariff and an Economy7 tariff which offers a lower tariff per kWh between the night-time hours of 22:00 and 08:30. In the case of VP 1,2, and 4, these revenues are available in addition to the revenues from providing grid services and increasing PV self consumption respectively.

4.8.6 Revenues and Savings: Results

Value Proposition	Type	Potential Barriers to Market	Services Revenue	Import Savings	Agg. Fees @20% Revenues	Total Net Income
VP1.1 Average Plug-In	Level 1	Hardware durability	N/A			£70
	Level 2	Insufficient Agg. Rev	£9	£64	£2	£31
	Level 3	Insufficient Agg. Rev			£2	£56
	Level 4	Charger cost too high	£84	£79	£17	-£154
VP1.1 High Rate Plug-In	Level 1	Hardware durability	N/A			£70
	Level 2	Insufficient Agg. Rev	£43	£17	£9	£12
	Level 3	Insufficient Agg. Rev			£9	£36
	Level 4	Charger cost too high	£313	£71	£62	£22
VP2.0 Low Call Rate	Level 1	Insufficient Agg. Rev	£102	£64	£20	£136
	Level 2	Insufficient Agg. Rev			£20	£106
	Level 3	Insufficient Agg. Rev			£20	£131
	Level 4	Charger cost too high	£178	£80	£36	-£78
VP2.1 High Call Rate	Level 1	Extreme case	£168	£64	£34	£188
	Level 2	Extreme case			£34	£158
	Level 3	Extreme case			£34	£183
	Level 4	Low revenues	£294	£80	£59	£15
VP4. Home PV Optim	Level 1	Good	£-	£80	N/A	£70
	Level 2	Good				£40
	Level 3	Good				£65
	Level 4	Charger cost too high	£1	£102	N/A	-£197

Table 7: Revenues and Savings: results

The largest revenues are provided using bi-directional charging, but these are offset due to the exceptionally high costs of the hardware even though a future hardware cost and an optimistic 10 year depreciation were chosen. Other than VP2.1, uni-directional smart charging cases are held back by their inability to offer services when not charging. This limits revenues from being sufficient to cover the cost of an aggregator.

4.9 Further optimisation of business models

Due to high costs and low net income challenging the initial business models, further work was undertaken to find workable opportunities. One common method of increasing revenue generation through aggregation is to stack services and optimise the utilisation of assets. However today's flexibility markets are often restricted by exclusivity clauses, requiring an asset to be dedicated to a particular service. There is speculation around the feasibility of stacking FFR with DNO deferral services when using bi-directional chargers. However if proven feasible, combining these streams could provide attractive revenues.

5.0 Optimisation 1: Average Call Rate Average Plug-In	VP 1.0, VP 2.0 & VP 4 Stacked	System OperatorServices, WPD's Secure Service & Home Solar Optimisation

This value proposition takes the average plug in rate from VP1.0 and combines it with revenues from VP2.0 offering DNO services at an average call rate, whilst optimising residential solar PV generation. Providing FFR and energy generation in support of DNO services can increase the risk of battery degradation.

5.1 Sensitivity: High Call Rate High Plug-In	VP 1.1, VP.2.1 & VP 4 Stacked	System OperatorServices, WPD's Secure Service & Home Solar Optimisation

This sensitivity takes the most extreme cases from VP1.1 and VP2.1 and combines them with import savings arising from the residential solar optimisation case. There are less solar savings available in this case due to the lower energy consumption of VP1.0. Combined energy storage and transfer can increase the risk of accelerated battery degradation.

Value Proposition	Type	Potential Barriers to Market	Services Revenue	Import Savings	Agg. Fees @20% Revenues	Total Net Income
VP5.0 Stacked Revenue	Level 4	Battery degradation risk, Customer with solar in constrained area	£263 BC	£91 B	£53	£1
VP5.1 Stacked Revenue	Level 4	Battery degradation risk, Customers with solar & high Plug-in Rates in constrained area	£608 BC	£91 B	£121	£278

These users must also exist in a sufficient population as to contribute a reasonable level of flexibility to an aggregator's portfolio. Further study is required to understand the potential size of this segment and the feasibility of stacking these services.

4.10 Further optimisation of business models

V2GB has focussed on opportunities for residential consumers to generate positive net income, however further opportunities are believed to exist for commercial fleet operators.

If a business is a large consumer of electricity it may be exposed to expensive demand TNUoS (Transmission Network Use of System) charges, (calculated through the TRIAD process). In such situations it could be possible to create opportunities for further savings of between £200 and £700.

However, many businesses already manage their exposure to TNUoS charges, meaning that relative savings might not be as lucrative. In fact TNUoS charges are being so widely well managed that it has been proven to be a poor deterrent against heavy consumption and is expected to be restructured in the very near future, which will likely eliminate the opportunity for these benefits.

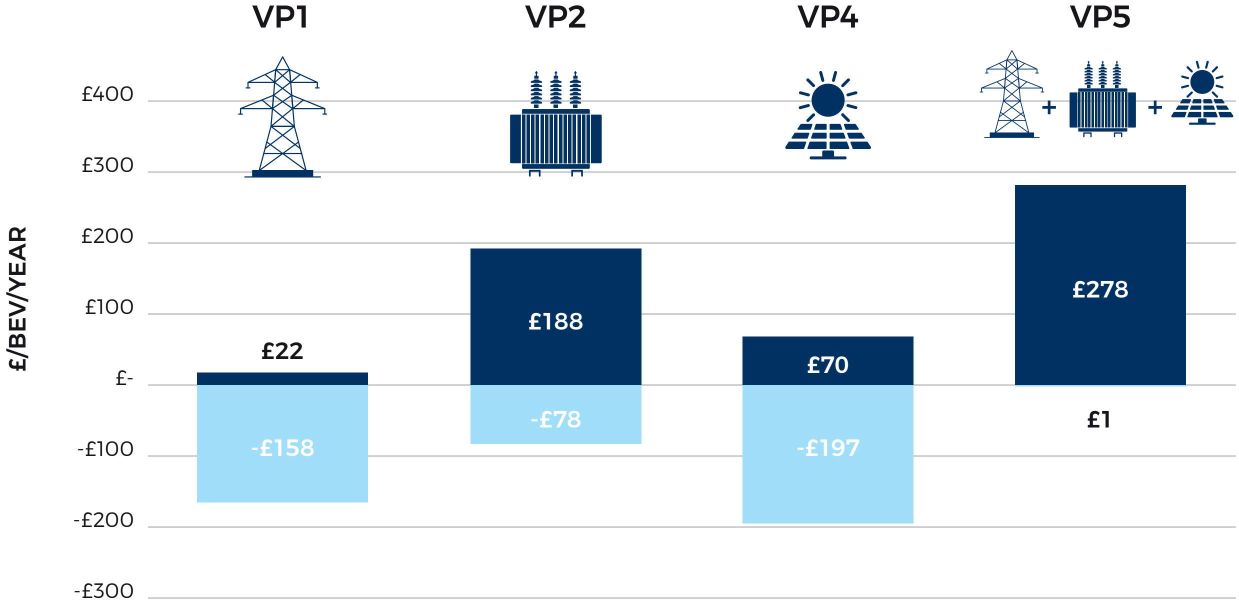
4.11 Revenues and savings: Conclusions

Analysis of the value propositions 1 through 5 shows that revenues can be created through the intelligent management of charging behaviour; revenues can also come from the provision of services and through savings on imported electricity. However, the high costs of providing V2G bi-directionally make it prohibitive and restrict the best revenues to very narrow types of BEV users (e.g. High plug-in, home solar exists, residing within a constrained network).

The requirement for the services of an aggregator also places restrictions on which business models can provide returns on investment, especially in the case of Smart uni-directional charging.

Net positive returns do look possible to achieve in providing DNO services; but further work is needed to evaluate this developing market to better understand their requirements and whether they can sustainably be met through the aggregation of a BEV fleet.

Range of net revenues from V2G value propositions



Range of estimated net revenues from proposed V2G value propositions

Requirements for market scale-up

5.1 Introduction

This chapter summarises the work undertaken by Element Energy under WP4. The task evaluates the development of V2G costs and revenues over the next decade, to determine whether and how the technology can transition out of niche applications and towards a scale which would have tangible and positive impacts on GB grid operation and decarbonisation.

The chapter first evaluates the evolution of V2G cost over the next decade, using a scenario approach to reflect a range of feasible technology developments and resulting costs. Revenue stacks are generated, drawing on WP2 as well as additional insights, again with high and low estimates to represent the variation in revenue opportunities that is expected to emerge. A comparison of annualised costs and revenues identifies the conditions under which economic viability may be achieved, and the drivers for this.

A GB power system dispatch model is used to determine the relative impact and benefit of passive, smart and V2G charging scenarios, and explores the dynamics of competition between various sources of flexibility, as identified in WP1. The chapter also evaluates consumer issues that can accelerate or delay adoption of V2G, and customer targeting and commercial models that may overcome these barriers as the market grows.

5.2 Development of V2G costs

5.2.1 Hardware cost reduction to 2030

We have projected the cost premium for a 7kW V2G charger out to 2030 using top-down and bottom-up methods and reconciled the results. Current costs are scaled from a Nichicon 6kW charger, excluding tax (Nichicon, 2018).

The top-down approach uses learning rates of a proxy technology, which is residential solar PV inverters. A low cost scenario uses a high learning rate of 15% (Trancik et al., 2015) and assumes 10% of global EV fleet participates in V2G in 2030 (Cenex, 2018). A high-cost scenario assumes a lower learning rate of 11% (El Shurafa et al., 2018) and that 7.5% of global EV fleet participates in V2G in 2030. In both scenarios it is assumed that Si-C and Ga-N will replace IGBTs to provide multiple benefits including size and weight reduction, efficiency improvement and leading to a 31% reduction of costs relative to IGBT alone. This gives an on-cost range of £656-£1164 in 2030.

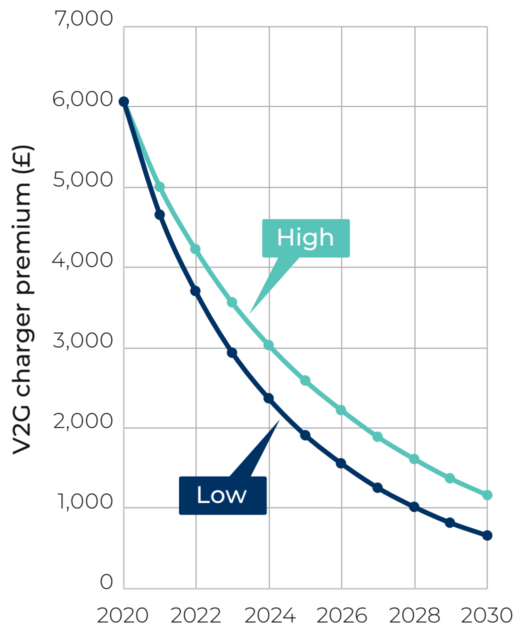


Figure 22: projected V2G charger premium

The bottom up approach identified the most costly components in the V2G charger and the expected change in costs of these out to 2030. Si-C and Ga-N technologies are assumed to enable the same cost savings as in the top-down approach. Furthermore the main cost components of the V2G charger are assumed to be the DC charger and the grid tied inverter. As both components use power electronics similar to those used in PV inverters, the cost of both is estimated using current costs of PV inverters. The DC charger is assumed to come at 70% of the cost of the power inverter[7]. Using a low cost of £0.08/Wp and a high cost of £0.12/Wp (Fraunhofer ISE, 2019) for solar inverters leads to a V2G charger cost of £660 and £1150 respectively, which shows good agreement with the top down approach.

Note that Nichicon currently include a 5y warranty for their V2G charger (Nichicon, 2018). A 5 year linear depreciation indicates an annualised hardware cost between £130 - £240. These prices are halved with a 10 year depreciation, which (despite warranties) may be more representative of what the residential market will accept (given deployment of residential PV).

5.2.2 Degradation

Proper accounting for lithium-ion battery degradation is important in determining the viability of V2G business models, but determination of impact is still at the research stage with recent papers providing apparently contradictory conclusions. Durbarry et al, 2017 showed that additional battery cycling due to V2G would shorten battery life; while Uddin et al, 2017 indicated that the use of prognostic battery aging models, active communications between vehicle and grid, and restricting battery use could avoid degradation. In response, our low-cost scenario assumes there is no cost associated with V2G degradation. For our high cost scenario, we use a simple degradation model based on publicly available information on Tesla batteries, and limited annual V2G use of 4500kWh/year, which indicates a degradation cost of 3.2p/kWh[8] or £150/annum in 2030.

5.2.3 Other costs

We also include the impact of efficiency losses (85% roundtrip) in terms of additional energy required. No installation costs are included. No grid connection cost (such as related to G99/1 or equivalent) is included. We further assume the high cost of unit testing and participation for residential assets providing balancing services to the SO can be avoided[9]. We have used a 2030 aggregation cost of £24/EV per annum proposed by Moixa. Perceived cost barriers are also excluded from the cost model, but are addressed subsequently.

5.2.4 Cost summary 2030

A summary of annual costs per EV is shown below. Five-year and 10-year linear depreciation is shown separately to demonstrate the impact expected lifetime will have on costs. We note that the residential PV sector expanded significantly, even when generous feed-in tariffs still required over 10-year payback for cost-effectiveness. For smart charging, costs are limited to aggregator control and dispatch. For V2G, the charger hardware-on cost dominates. Should battery degradation be exacerbated by V2G operation, it would have a profound effect on annual costs.

7 Personal communication with industry stakeholders

8 See full WP4 report for calculation.

9 Currently being assessed by National Grid ESO in the Residential Response Project.

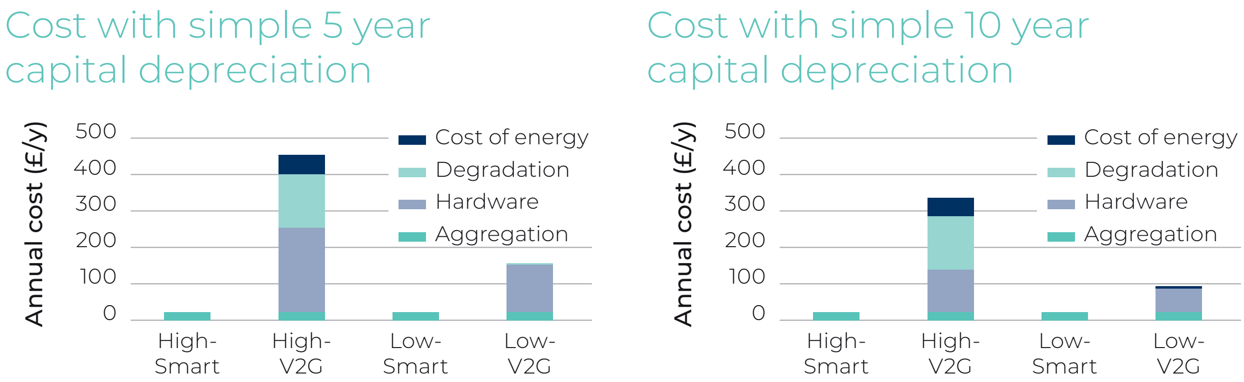


Figure 23: V2G costs in 2030 based on 5 year (left) and 10 year (right) depreciation)

5.3 Development of markets for V2G services

5.3.1 DNO services

Under current regulation, residential 7kW chargers can be connected to distribution network and any cost associated with this will be socialised. For V2G, a connection agreement (G99/1 for export above 3.7kW) would be required. Currently some UK DNOs (WPD and UKPN) are trialling and testing active congestion management zones, which could provide a revenue stream for actively managed and V2G chargers. DNO revenues are based on WPD published data on their active congestion management zones, (Gone Green 2024 scenario). As agreed with WPD, prices are unchanged out to 2030.

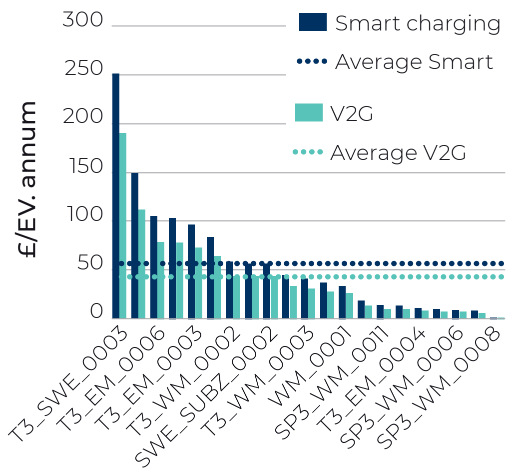


Figure 24: annual DNO revenues in WPD congestion zones in 2030

The graph shows the predicted annual revenue per EV, for smart charging and additionally for V2G, across the 21 zones that WPD expect to manage. Note that these 21 zones represent a small fraction of all WPD areas i.e. these are only zones where congested is expected. Most zones are expected to have zero market value for congestion. The reason for a difference in revenue between regions is due to the expected call rate (number of hours per day, seasonality of calls etc). The average value for Smart is £57/EV.annum, and for V2G it is £43/EV.annum. Revenues for V2G are incremental, i.e. in addition to those for smart charging. The daily charging requirement is 6.6kWh/day; while the degradation throughput limit is equivalent to 5kWh/day.

From this the high scenario takes the average of the five most highly utilized zones, while the low takes the average of 5 least utilized zones. Note that most areas have value of zero – no congestion expected.

5.3.2 System Operator services

WP2 indicates that frequency regulation could be a significant component of revenues currently. However it is a small fraction of the overall electricity market and the emergence of battery storage in this market has significant reduction in the specific value of services in recent years. Our estimate for 2030 revenues for frequency response are based on CENEX WP 2 data (using the lower FFR specific value of £5/MW/h accounting for significant competition for service provision), extrapolated to 2030 by estimating future FFR demand and diluting per EV value as appropriate. Our high scenario assumes high plug-in rates, and low assumes low plug-in rates, as per the WP2 report.

Balancing markets with products requiring response times on the order of several minutes to one hour are of significantly larger size than frequency regulation markets. Demand for balancing products is expected to grow with higher VRE penetration as forecasting errors of intermittent renewable generation lead to an increased need for reserves in the system (Hirth & Ziegenhagen, 2015). However many factors determine the size of the market and value of services[10]. Expected higher service volume requirements (due to VRES uptake) are balanced by price downward pressure through System Operator cooperation and increasing number of technologies and suppliers in balancing markets.

5.3.3 Import savings/arbitrage

Arbitrage opportunities in wholesale electricity markets were identified as an enduring value point for V2G in the long term in WP1. With increasing penetration of Variable Renewable Energy (VRE) sources like wind and solar in electricity, prices are expected to become more volatile. Such fluctuating prices offer an opportunity for flexible assets such as storage and DSR, they are in fact seen as a central signal to incentivise flexibility of demand as well as generation in electricity markets for systems with high penetration of fluctuating energy sources. We use the Element Energy Whole System Dispatch model to generate estimates of 2030 arbitrage revenues/savings.

5.3.4 Revenue stack 2030

Figure 25 shows the estimated revenue stack for 2030, with low and high revenue estimate for each of smart charging and V2G. In contrast to WP2 near term revenues, in 2030 the revenue stack is more reliant on DNO services and on import savings. DNO revenues will only be available in congested areas with an appropriate market mechanism, and so are time and location sensitive. V2G-based arbitrage revenues will be more exposed to issues related to degradation than frequency response, given the larger volumes of energy required to generate these revenues.

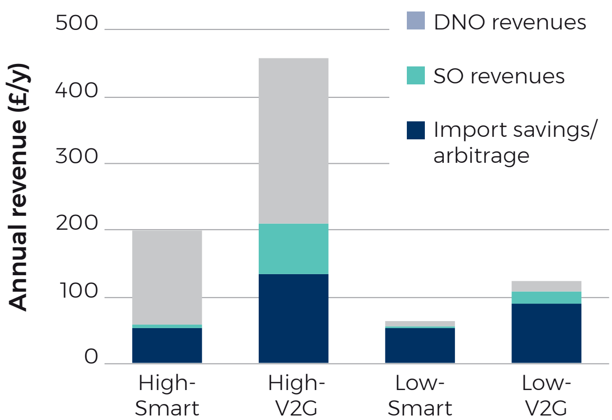


Figure 25: annual Smart and V2G revenues in 2030

10 For example, revenues in Germany have eroded as four balancing areas were integrated into one, and increased international cooperation of System Operators.

5.4 System impact, 2030

5.4.1 V2G net costs, 2030

Estimates for annual 2030 costs and revenues per vehicle are shown below. The more challenging target of 5-year depreciation of hardware costs is shown on the left, and 10-year on the right.

With a 5-year lifetime, low costs and high revenue assumptions, net profitability could occur by the mid 2020's. With a 10-year lifetime, in a best-case scenario residential V2G could be profitable in the near future, with this being reliant on a combination of high plug-in rates (for FR), in a revenue generating congestion management zone (for DNO revenues), low hardware cost estimates and no degradation issues.

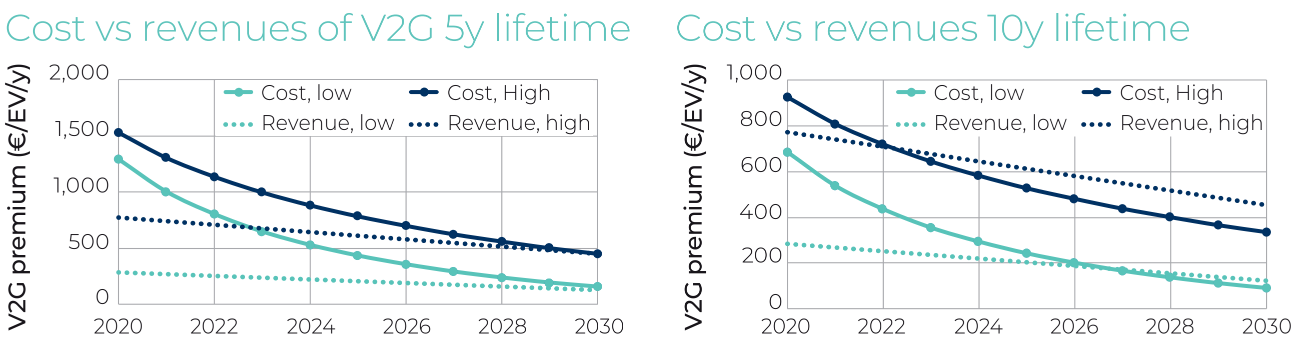


Figure 26: V2G cost and revenue projections for 5 year depreciation (left) and 10 year depreciation (right)

5.4.2 Whole system impact of charging scenarios

Element Energy used its whole system dispatch model to determine the net system cost/benefit of passive (uncontrolled) smart, and V2G based charging scenarios. The model also includes the impact of other flexible loads, such as utility battery energy storage.

The model is based on hourly profiles of demand (shiftable and non shiftable) and weather data to determine heating requirements and hourly VRES (wind and PV) output. 2030 UK power sector capacities are taken from ENTSO-E Distributed Energy scenario.

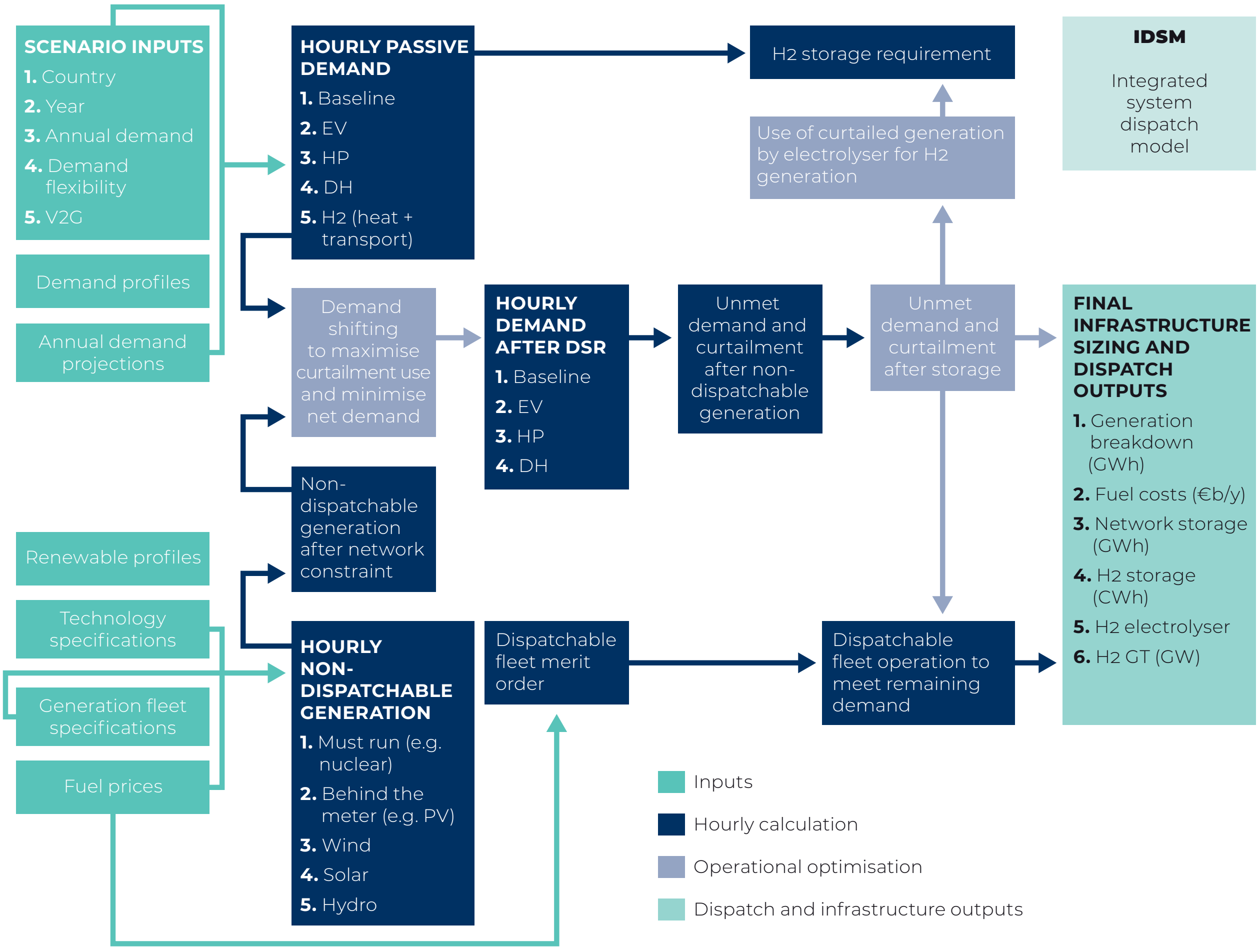


Figure 27: Element Energy Integrated Supply and Demand Dispatch model

Transport demand is based on the stock of electric vehicles, their efficiency, the daily usage, and arrival/departure times from home and work to generate baseline electrified transport demand. Grid-responsive smart charging can schedule charging to times of most use to the grid, while still providing vehicles have sufficient charge for transport.

Country-specific hourly weather data is also used to generate hourly load factors for wind and solar production. An initial specification of the VRES generation fleet is used and combined with the demand data to generate initial net load curves.

Demand shifting is deployed to minimise net demand and minimise generation curtailment. Network capacity is adjusted to optimise between demand driven and network curtailment. The dispatchable generation fleet is then deployed in merit order to fill in the supply gap. Remaining unmet demand is supplied by seasonal storage, and generation capacities are updated to reflect this.

5.4.2 Whole system impact of charging scenarios cont...

Once all hourly demands are met, annual system performance metrics are evaluated (CO2, limits on biomass use) and generation inputs adjusted to meet targets. Final outputs include generator capacities, network capacities, and storage capacities, and associated costs.

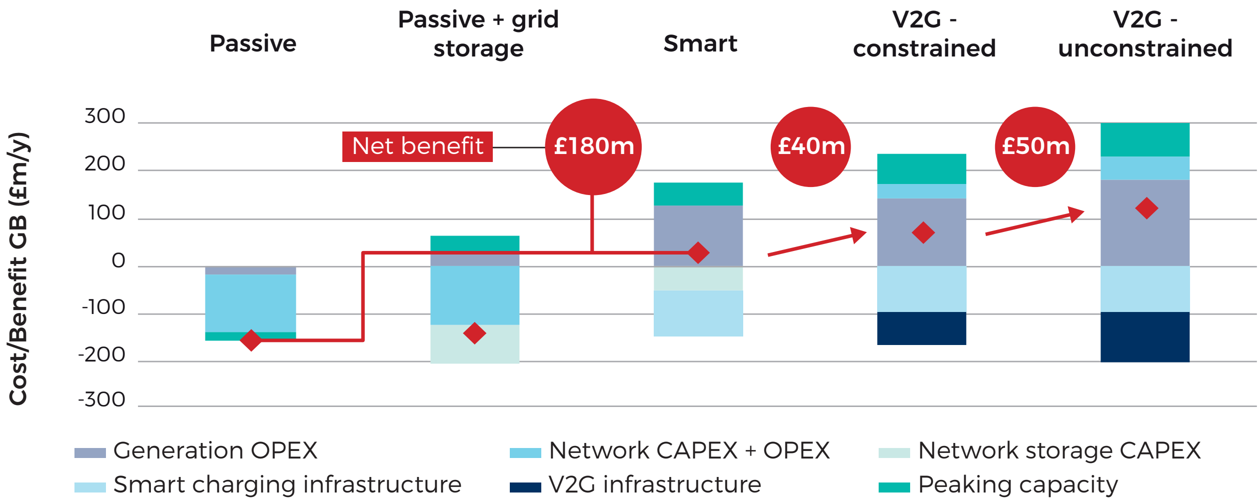


Figure 28: system cost and benefits of different charging scenarios

Generation opex refers to fuel use in thermal generation plant; this reduces when flexible demands help reduce VRES curtailment and when avoiding inefficient peaking plant. Peaking capex refers to generation peaker plant capacity required. Network capex/opex is the annualised cost of network capacity required in each scenario.

The reference case is the ENTSO-E Distributed Generation scenario where the additional EV energy requirement is constant for each hour of the year. Relative to this, passive charging results in an additional system cost; this is because the pattern of residential arrival/departure times means EV drivers are likely to begin charging on arrival at home. This increases peak loads on the system. Most of the cost is at distribution network level as EV charging uses up available network capacity. Network storage can be introduced to this system, which reduces peaking plant capacity, reduces peaking generation and results in a slight overall network benefit.

Deployment of smart charging eliminates additional network capacity investment; it also reduces peaking plant requirements and reduces thermal generator fuel use. Network storage requirements are also reduced. Overall, this scenario saves £180M/annum relative to a passive charging scenario.

5.4.2 Whole system impact of charging scenarios cont...

Two V2G scenarios are also evaluated. “Constrained” applies a V2G energy throughput limit of 2000kWh/annum, while this is not applied in “Unconstrained”. V2G is deployed up to an economic threshold- the point at which the marginal costs of V2G exceed marginal benefit – which is circa 800k V2G chargers out of an EV fleet of 4M vehicles.

Although V2G introduces additional hardware costs, it completely replaces network storage requirements, avoids even more peaking plant capacity, and could potentially generate some revenue from avoided network investments. Relative to smart charging, V2G (constrained) could generate a net saving of £40M/annum. Unconstrained charging allows each vehicle battery to do more, resulting in greater savings and economic deployment. Relative to constrained, this scenario could generate a net saving of £50M/annum to give an overall V2G saving of £90M/annum relative to smart charging.

5.4.3 Synergy between VRES and flexibility

Sources of flexibility, including smart charging, grid batteries, or V2G, work to reduce the mismatch between energy supply and demand (i.e. to flatten the net demand curve). The modelling shows that as deployment of flexibility assets increase, the average annual utilisation of each asset decreases[11]. This is shown in the left hand graph below.

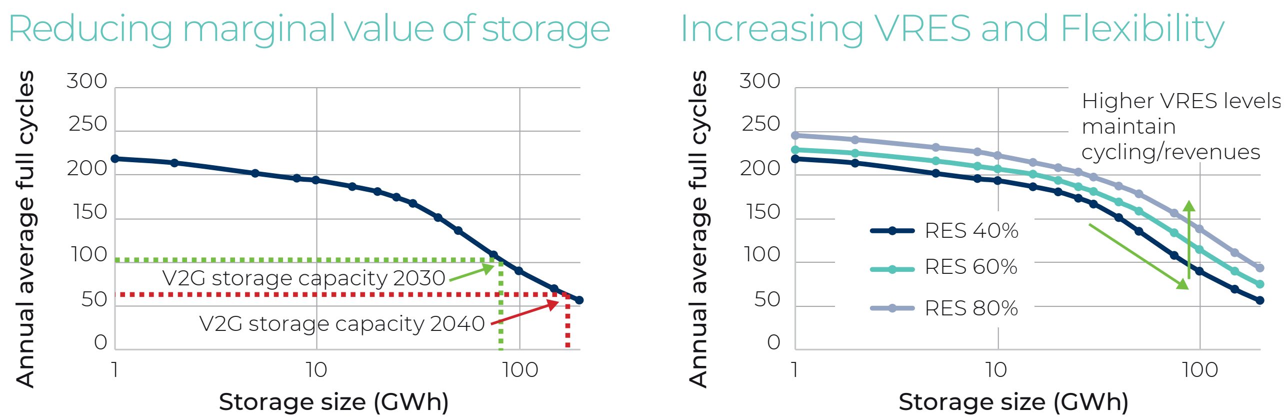


Figure 29: annual cycling vs cumulative storage capacity

11 Where all other aspects (such as VRES penetration) are held constant.

5.4.3 Synergy between VRES and flexibility cont…

As increasing storage volumes are deployed, the annual utilisation rate (in terms of full cycles per annum) decreases (blue line). This presents a challenge to sustained deployment of storage, because later deployments reduce the average annual cycling (revenues) of the whole battery fleet, until a threshold of economic viability is reached where revenues cannot sustain the investment. We note for reference the equivalent storage capacity of the V2G fleet in 2030 and 2040, assuming all EVs have V2G capability. This would provide storage capacities of national significance but would also erode annual cycling of storage assets to uneconomic levels. The impact between V2G and network storage assets will need careful consideration.

However, there is a positive synergy between the deployment of storage capacity and increased uptake of VRES to decarbonise energy systems (above graph on right). Higher VRES deployments tend to increase the mismatch between supply/demand, and so greater battery storage capacities can be economically deployed to flatten the net demand curve. Continued deployment of VRES in line with decarbonisation targets will support the sustained deployment of flexibility solution such as batteries. This is an essential part of the self-reinforcing dynamic between greening electricity and smartening demand flexibility.

5.5 Consumers and business models

5.5.1 Challenges

While the sections above deal with an economic evaluation of EV costs and revenues, they do not include a specific representation of customer concerns. Early adopters might be willing to overlook or ignore issues which would adversely impact economic viability, while the mass market may have concerns which translate into an excessively high estimate of costs. Understanding consumer concerns and values is critical to developing a viable V2G business model with a net positive value proposition. Both early adopters of EV and charging technology and the mass market currently have a range of perceived risks posing difficulties to V2G development. This section aims to identify and quantify the concerns associated with consumer participation of V2G and identify solutions or potential incentives to ensure the benefits of V2G outweigh the costs to targeted consumers.

Transferring control of charging
Some consumers may be concerned by giving up control of the charging and discharging of their EV battery, due to lost convenience or reduced certainty regarding vehicle state of charge. While giving up control is not specific to V2G it is expected to be more pronounced with V2G.

Range anxiety is one result of autonomously controlled charging as consumers may have little control over the level of discharge beyond setting a minimum threshold. Controlled discharging may also lead to data protection concerns. Distrust of the operator controlling charging may result in higher perceived costs of battery degradation.

5.5.1 Challenges cont...

Quantifying the value consumers place on control is difficult as it is tied to many other elements; however, a range of research reveals that the majority of EV drivers are open to allowing controlled charging. One study found 61% of EV drivers would consider allowing utilities to control their charging to support the greater good despite some lingering concerns about privacy and control[12], while recent work in GB by electric nation shows the majority of EV drivers are not aware of controlled charging events and are overall supportive of the concept[13]. About 25% of consumers can be swayed to participate in exchange for access to their vehicle data, but their willingness is sensitive to impacts to their data, flexibility and battery health. Research shows participation is reduced drastically with restrictive contractual arrangements[14] and nearly three quarters of participants would not sign up to controlled charging if the state of charge of their vehicle was not considered in the optimisation[15].

Minimising range anxiety

Due to a diversity of consumers values, there is no clear cut-off SoC that is acceptable or not to all consumers[16]. However, one study found that that consumers value their remaining range more as the guaranteed minimum state of charge drops[14]. In a combined choice experiment, the study showed consumers placed the same dis-benefit of reducing range from 175miles to 25 miles, as in tripling the initial price up to $84,000. Guaranteeing a minimum of 125 miles would require only $10 per mile or the equivalent of a $500 increase in the initial price). Considering the average BEV driving ranges are predicted to reach 275 miles by 2022, it is possible the minimum range could be limited to 100 miles in the future while still providing enough discharge for profitable V2G operations. Using that study's consumers' non-linear value function and ignoring discounting, this would equate to a monthly compensation requirement of approximately £18/month. It is possible this compensation could be reduced further as research shows EV owner's confidence in the driving range increases with time[17].

There are several ways to limit the range anxiety compensation for V2G participants. V2G could be initially targeted at those consumers who do not require compensation because they have other options. For example, a California study found no range anxiety for drivers who could rely on other transportation options or fuel sources like multi-car households or those consumers with PHEVs[18].

As EV battery capacity continues to grow, it will be easier to guarantee the acceptable minimum ranges to those groups identified as requiring least compensation and the customer base can expand. Consumer perceived value for higher driving ranges can be expected to simultaneously decrease as the expected distances between charging options decreases. The charging infrastructure development could allow lower compensation and further expansion of the target customers.

12 Bailey and Axsen, 2015, Anticipating PEV buyers' acceptance of utility controlled charging
13 Electric Nation, May 2018, Smart charging summary
14 Parsons et a., 2014, Willingness to pay for vehicle-to-grid (V2G) electric vehicles and their contract terms
15 Bauman et al., 2016, Residential Smart-Charging Pilot Program in Toronto: Results of a Utility Controlled Charging Pilot
16 Innovate UK
17 Burgess et al., 2013, Assessing the Viability of Electric Vehicles in Daily Life: A Longitudinal Assessment (2008-2012)
18 Sovacool et al. 2017, Tempering the Promise of Electric Mobility? A Sociotechnical Review and Research Agenda for Vehicle-Grid Integration (VGI) and Vehicle-to-Grid (V2G)

5.5.1 Challenges cont...

Protecting data security

Privacy and data security are key concerns involved with the collection and aggregation of vehicle driving and charging data for many V2G consumers. One study found nearly a quarter of respondents believed V2G to be an invasion of privacy[18,19]. For the majority of consumers, the perceived risk that the data may also be used for other purposes and shared with other stakeholders may be larger than the real risk because consumers tend to distrust traditional electricity companies. Ofgem reports a third of consumers do not trust their supplier to treat them fairly, particularly for younger and wealthier customer segments[20]. With the recent and rapid development of V2G and smart charging technology, fit-for-purpose regulation protecting consumer data has not yet been put in place. Without a regulatory delineation of where information is used and shared, this distrust and concern about misuse of their data remains a real concern for consumers.

The development of clear regulation surrounding ownership and use of data for smart charging and V2G will reduce much of the real data security risks. Transport data security is a top priority of the current regulatory review being conducted by the Department of transportation[21]. The new data and privacy regulation being developed will be focused on the role of smart charging but could be created with sufficient flexibility to adapt to V2G capabilities.

Consumers may trust V2G providers more if they can easily see the personal and social benefit of their data on the service provision to ensure it is being used as expected. As EVs are increasingly connected to the internet and supported by digital capabilities, the perception of their data use may become more like that of the mobile phones.

Increasing plug-in time

Maximising plug-in time is critical to maximise the revenues from V2G, yet data shows that consumers tend to minimise plug in events. While private cars are parked over 90% of the time[22], research shows consumers prefer to plug in their car for an average of 5 hrs/day[17] and tend to charge every other day[23]. EV drivers perceive the action of plugging in their vehicle to be a hassle. EV drivers minimise this transaction cost similarly to how they would have refuelled a traditional car by typically plugging in when they believe the car is in a low state of charge or to prepare for a trip. Research for UKPN[24] revealed that EV owners tend to charge when they need to: on weekdays; if they are commuters without workplace charging; and if they have smaller batteries.

19 Bailey and Axsen, 2015, Anticipating PEV buyers' acceptance of utility controlled charging
20 Ofgem, 2017, Consumer Engagement Survey 2017
21 Stoker, 2019, DfT unveils mobility regulatory revolution to capitalise on 'unprecedented' shift in transport
22 Parsons et a., 2014, Willingness to pay for vehicle-to-grid (V2G) electric vehicles and their contract terms
23 Irish, 2017, V2G: The role for EVs in future energy supply and demand
24 Element Energy, UKPN, 2019, Recharge the Future-Charger Use study

The impact of requiring higher plug-in rates varies widely showing how sensitive different customer segments may be to plug-in requirements. One study found increasing plug in times from 5 hours to 10, 15 and 20 hours was the equivalent of increasing the price of the EV by $1,400, $4,500, or $8,504 respectively[25]. Incentivising for ca 10 hours per day would require a monthly compensation £11/month. However, in a different study when participants were contractually required to plug in for just their normal 5 hours, they required £150/month compensation[26]. This disparity reflects the perceived negative impact on consumers by the use contracts and large impact of consumer preferences.

Financial rewards or electricity cost savings could be used to compensate for the remaining transaction costs. Plug-in rates increased by 12% for every dollar savings in a UC Davis trial, so V2G offerings could include special tariff structures to incentivise particular plug-in times with reduced prices or free charging on the weekends or for specific customer segments like non-commuters. Consumers prefer upfront payments/ discounts and short-term pay-as-you-go rewards from supply companies over annual cash-back payments[26].

Minimising perceived costs of degradation

As well as the true value of degradation, successful V2G businesses will have to address the perceived disutility of V2G exacerbating battery degradation. In early trials, consumer costs may also be higher due to the uncertainty that remains on V2G battery degradation. One study found early EV adopters require 2-3x more compensation than the mass market to enrol in V2G because of their increased understanding of the true costs of battery degradation and their concerns about this risk[27].

As the cost of EV batteries continues to steadily fall, the cost of replacing the battery will fall as well. In addition, studies indicate that the levels of battery degradation may be manageable by controlling the depth and state of charge and temperature of the battery, with some even proposing that battery life could be extended with adequate infrastructure to monitor battery health[28]. V2G algorithms could focus on ensuring minimum battery degradation by controlling the SoC while future arrangements for extending the life of the battery should continue to be examined including any additional infrastructure required to monitor the 'health' of the battery[29]. For early adopters, businesses may still need to pay some consumers for perceived battery degradation and the resulting reduction in range while risks are unknown. To reduce the costs to the V2G provider to as little as possible, alternative business models could be considered that absorb the cost of battery replacement to minimise the cost paid to consumers for their perceived risk.

25 Parsons et a., 2014, Willingness to pay for vehicle-to-grid (V2G) electric vehicles and their contract terms

26 Steward, 2017, Critical Elements of Vehicle-toGrid (V2G) Economics

27 Sovacool et al. 2017, Tempering the Promise of Electric Mobility? A Sociotechnical Review and Research Agenda for Vehicle-Grid Integration (VGI) and Vehicle-to-Grid (V2G)

28 Uddin et al, 2017, On the possibility of extending the lifetime of lithium-ion batteries through optimal V2G facilitated by an integrated vehicle and smart-grid system

29 Landi and Gross, 2014, Battery Management in V2G-based Aggregations

5.5.2 Solutions

Targeting customer segments

A viable business model must deliver a net positive value (of sensible and perceived costs) to the end-user. Research suggest certain customers will place higher value on the non-economic V2G benefits than others. For example, a study of the Nordic countries Willingness to Pay (WTP) found most regions wouldn't pay anything for the benefits of V2G as they did not place any value in them; however, in Norway they were willing to pay €4000 to participate in V2G because of an awareness of the electrification impacts of the mature EV market[30]. Different values can be seen amongst early adopters of EVs vs. the mass market.

Successful business models could tailor value propositions to target specific customer segments who highly value the social and environmental benefits as they may require the least monetary compensation. Gaining a better understanding of which customers value what costs and benefits and by how much may enable cost reduction methods and targeted business models.

Alternative value chains

One solution to increase consumer trust may be to have automotive OEMs rather than energy utilities take responsibility for the V2G value chain. Unlike with energy suppliers, OEMs have a strong brand loyalty. If consumers trust the OEM to ensure their EV is protected, it may lower their perceived risks of the V2G provider putting energy system needs over the health of the battery. OEM's will also have a stake in ensuring efficiency of the supply chain because V2G services will provide them with an ongoing revenue that will be necessary to replace the (expected) reduction in revenues from EV maintenance and part manufacturing. Since the OEM may not have expertise in the energy sector, they could partner with an energy supplier and aggregator to receive energy services at low costs under their branding as a white label supplier to ensure the participation of the energy supplier is trusted in the same way as the OEM.

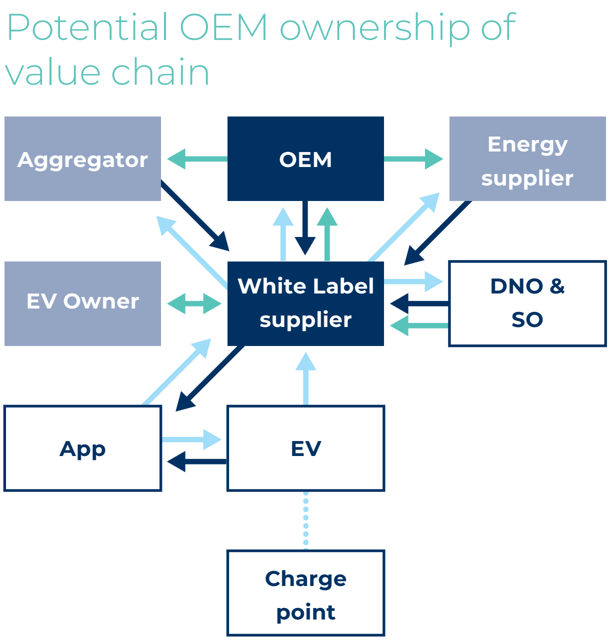


Figure 30: potential OEM ownership of value chain

30 Kester et al., 2018, Promoting Vehicle to Grid (V2G) in the Nordic region: Expert advice on policy mechanisms for accelerated diffusion. 2018.

Leasing models

Battery warranty or leasing models are both potential commercial methods of transferring the risk of degradation of a battery from an EV owner onto the OEM or leasing company.

As the vehicle sector moves away from ownership toward leasing and integrated mobility services, V2G may be provided as a combined offering with battery and EV leasing models to take the risk of battery degradation away from the consumer. It can be expected that EV and battery leasing will grow as GB has the largest leasing market in Europe with over 85% of new private cars bought using finance[31] and 5% growth in automotive leasing[32]. Battery leasing is also becoming increasingly popular in the EV sector as it allows EVs to be cost competitive and negates battery replacement anxieties. Battery leasing costs are nearly half that of leasing an entire car (£60-70/month), thus any options to reduce these leasing price could substantially boost EV sales for OEMS.

5.6 Conclusions for market scale-up

- A combination of top-down (learning rate) and bottom-up (component based) cost analyses aligned on projections of 2030 on-costs of a 7kW V2G charger of between £660-£1160. This hardware investment dominates annualised V2G costs if the hardware is depreciated over 5 years, and remains a major component of the cost stack if depreciated over 10 years.
- The cost of degradation would be large enough to drive the economic case for V2G, should it emerge that V2G operation increases battery degradation. Careful consideration of cycling, and V2G based dispatch is required to minimise this.
- Erosion in the specific value of Frequency Response seen in recent years can be expected to continue, and by 2030 other revenue streams will drive residential V2G viability.
- Emerging markets for distribution constraint management could become the dominant revenue stream for V2G, but only in areas where acute congestion is expected. This revenue stream is also subject to policy risk should regulation move away from socialisation of residential charging costs. Work is required to streamline grid connections such as G99/1 or equivalent and limit the cost.
- Opportunities for import savings/arbitrage will increase, but as these services require larger energy throughput compared to FR, their viability will be dependent on degradation.

31 Reuters, 2017, More UK cars bought on credit - data

32 Lease Europe, 2017, Key Facts and Figures 2017

5.6 Conclusions for market scale-up cont...

- With a 10-year lifetime, in a best-case scenario residential V2G could be profitable in the near future. However this is reliant on a combination of: high plug-in rates (for FR), in a revenue generating congestion management zone (for DNO revenues), low hardware cost estimates and no degradation issues.
- Hardware costs must come down aggressively to allow economic viability beyond unusual edge cases.
- As hardware costs are paramount, it is critical that critical that commercial models are able to annualise cost over long life (10 years +) and with low discount rate.
- Trials are required to determine the true impact of V2G operation on battery degradation.
- Relative to unmanaged charging, smart charging could generate system savings of £180M/annum, with benefits throughout the GB power system.
- Additionally, V2G operation could save between £40M-90M/annum, with the variation due to the application of an annual constraint on V2G-based energy throughput.
- Competition between flexibility sources means that the marginal value of flexibility reduces as its deployment increases.
- However there is a positive synergy between flexibility and VRES deployment which can simultaneously support high VRES deployment and sustain economically viable revenues for flexibility assets such as smart charging and V2G.
- To be viable, introduction of V2G into the residential market will need to identify consumer groups with high plug-in rates, high range EVs with ample rapid charging availability.
- In addition, novel business models will need to be developed to remove any customer concern about V2G based degradation (whether actual or perceived risk).

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RIDING SUNBEAMS

Before Dawn

Progress Report
February 2019

Authors

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10:10 Climate Action

10:10 Climate Action is a registered charity on a mission to speed up action on climate change. Whether it's our world-leading Solar Schools campaign, research to generate low carbon heat from parks, or fighting the ban on onshore wind, everything we do is about inspiring more people to take more action on climate change. Charity no: 1157 363.

www.1010uk.org

Community Energy South

Community Energy South was established in 2013 as an umbrella organisation and regional hub enabling its members (local community energy groups and community organisations) to grow as sustainable low carbon businesses in the south east of England.

www.communityenergysouth.org

The Rural Community Energy Fund

The Rural Community Energy Fund (RCEF) is a £15 million programme, jointly funded by the Department for Environment, Food and Rural Affairs (Defra) and the Department for Business, Energy & Industrial Strategy (DBEIS). It supports rural communities in England to develop renewable energy projects which provide economic and social benefits to the community.

Designed by Matt Bonner.

Executive summary

- Our previous work showed that using solar to power trains on dc electrified railway lines should in principle be technically viable and commercially attractive.
- The next phase of our research has established that this approach should work in practice as well as in principle.
- Our consortium carried out six site-specific feasibility studies at real-world locations on behalf of local community energy groups in the south-east.
- We found that all six potential pilot solar traction farms, with a combined generating capacity of 27.15 MWp, should be viable for development.
- We examined the potential for long term contracts to procure traction power from the proposed lineside community solar farms. They appear to be capable of reducing rail operating costs and carbon emissions, at the same time as underwriting capital investment in new, unsubsidised renewable capacity. They will also generate revenue for local community benefit funds.
- We can use existing equipment (repurposed from outside the rail sector) to connect solar to the high voltage ac feeder system that supplies dc rail traction substations with power from the grid. This greatly reduces development timescales compared to our earlier proposal for a dc-dc connection.
- This approach also helps overcome the big technical challenge for rail renewable traction power: the intermittency of both the load and supply. Using this method, we will not usually need to integrate storage.
- Our next step will be to show that the technical connection works safely and efficiently in the real world: on the operational railway. We have secured funding to design, build and connect a 'First Light' demonstrator solar traction unit to the Wessex Route during 2019.
- Evidence from the trial will be used to inform a new rail industry code for the direct connection of renewable generators to rail traction systems.
- If all goes well, the first community solar traction farms could connect to UK railways as soon as 2020.

A word from our community energy partners

BHESCo are thrilled to be a partner in the revolutionary Riding Sunbeams project, working towards establishing a world first for renewable energy by powering our rail system with clean, solar power.

Dan Curtis
Brighton and Hove Energy Services Coop

We have been really impressed with the innovation and collaboration that this project has produced. We have two sites that our feasibility studies have shown could generate over 5MW of electricity. These will generate clean energy and also provide significant financial benefits for communities in north west Hampshire.

Andrew Thompson
Hampshire Renewable Energy Cooperative

British innovation and engineering has led the world since the start of the railways; this pioneering work is continuing to evolve by taking a huge leap into a world-changing renewable way to power transport. So it is wonderful to see our project, as part of a cluster of six, pushing forward this incredible world-leading innovation, raising the prospect of making not only our projects into catalysts for zero-carbon living in our communities, but opening the door for many more to follow by setting a precedent that can be replicated. This is a classic win-win-win-win-win for investors, local communities, Network Rail, cheaper travel and the global environment.

Dr Alister Scott
Cuckmere Community Solar

At Repower Balcombe we have seen the Riding Sunbeams project grow from our initial idea to the detailed work needed to make it happen. It is great to see the enthusiasm from the rail industry for this groundbreaking use of solar power.

Tom Parker
Repower Balcombe

Hassocks village grew up around its railway station in the 1840s, later to be the first electrified line in the UK. It seems an appropriate place to test the feasibility of the next big technological leap: powering trains with solar power. HKD Energy is pleased to be part of the pioneering Riding Sunbeams project, working to make a significant contribution to reducing carbon emissions through community led renewable energy.

Juliet Merrifield
Hassocks, Hurstpierpoint, Keymer and Ditchling Transition (HKD)

The Riding Sunbeams project is without doubt one of the most exciting opportunities to harness technical innovation and the creativity of social enterprise. We have a talented team and world class partners with whom we will deliver environmental, social and commercially sustainable solutions that will revolutionise our approach to powering the transport network.

Ivan Stone
Chair, Riding Sunbeams

Introduction

In 2014, 10:10 was working with a community energy group in Balcombe, Sussex trying to find a grid connection for their community-owned solar farm. It set technical director Tom Parker wondering: why couldn't we plug the solar panels directly into the local electrified rail line?

Why not indeed? So in 2017, we carried out a preliminary, high level study to see if it would be possible to build small, community-owned solar farms alongside railways to supply renewable electricity directly to the tracks to power trains.

Direct supply of solar power to rail traction systems has still never been done anywhere in the world. Our study found that not only is solar traction power technically feasible, it also makes sense financially for solar generators and railway operators in today's market conditions. We also found that there is huge market potential for this idea in the UK and worldwide.

The obvious next step was to begin to take this concept off the drawing board and into the real world.

So at the start of 2018, we gathered a handful of established community energy groups in the south of England to develop the first ever portfolio bid to the government's Rural Community Energy Fund. With their support, we commissioned full, site-specific feasibility studies at six locations (identified in our previous study) for pilot solar traction farms. At the same time, we continued to work closely with Network Rail to find the best technical solution for safely and efficiently feeding intermittent renewable generation into the traction system.

This short report serves as a status update on our progress towards making the world's first community solar traction farms a reality.

Solar traction power solves two problems for decentralised renewable energy generation: it provides a new way to finance unsubsidised solar in the UK, and offers a way to circumvent grid capacity constraints. Meanwhile, it gives rail operators a chance to reduce traction electricity bills, cut carbon emissions and potentially to deliver completely new kinds of social benefits to lineside neighbours.

We want to lay the tracks for community- and commuter-financed solar traction power to be rapidly commercialised and deployed. Our mission is to make this happen for the benefit of railway routes and the communities that host them.

February 2019

Community energy and the railways

From small beginnings back in 1996, today there are community energy groups across the UK. They do vital work supporting their communities to build locally owned renewable energy projects and providing much needed community led energy advice services.

In England, Wales and Northern Ireland there are over 230 groups, generating over 202 GWh of electricity each year, avoiding 71,000 tonnes of CO_2 emissions and providing enough electricity to power 67,000 homes.

Our vision is for community energy groups to play a central role in connecting renewable energy to the railways – and become a catalyst for decarbonising rail travel in the UK and beyond. So during 2018, working closely with Network Rail and several community energy groups in the south-east, we examined the technical and commercial feasibility of six potential solar sites located close to railway lines.

By working with lineside communities and rail passengers, we will encourage local investment in these schemes – creating community benefit funds too. This will provide a social contract focused on local communities, supporting the vulnerable and promoting low carbon transport and energy.

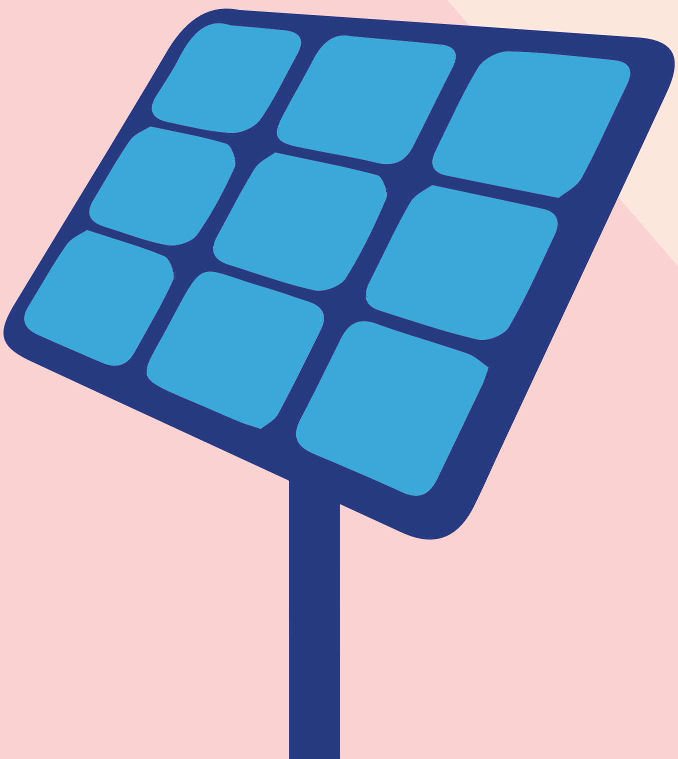
The Riding Sunbeams project is truly a world first and it is amazing that some of the technology and thinking that will make it possible is being developed. This has the potential to power railways not just in the UK but across the globe. But Riding Sunbeams is not just about innovative technology; it is about developing equally innovative ways of owning and financing renewable energy. At the heart of the project is the building of community owned, decentralised renewable energy systems. This is as much the future as the technology is.

Martin Heath, from Basingstoke Energy Coop, who supported the 2018 feasibility study as a technical consultant.

Technical challenges

Our 2017 study produced a high level design specification for a dc-dc inverter to allow us to connect solar panels directly to traction substations on the dc rail network. In many ways this is the optimal engineering solution, but there are some major practical barriers. The central issue we faced was that this bespoke equipment simply does not exist on the mass market. Developing, testing and accrediting new equipment for use on the railway requires a multi-year, multi-million pound process in order to achieve the required Rail Industry Readiness Level (RIRL).

Our research also showed that in most practical applications of solar traction power direct to the substation, we would need to integrate some form of storage technology – due to the inherent intermittency of both the load and the generation. But storage technology is very immature in the rail sector, and is only now beginning to be written into rail codes. Moreover, to make the economic case for integrating storage, we would need to rely on value stacking across a range of other functions on the rail side, such as improving system receptiveness to regenerative braking. But it's not yet clear what the financial value of such functions would be to the rail network. We would need a large and detailed piece of analysis before we could even develop an outline business case for lineside storage on the traction system.

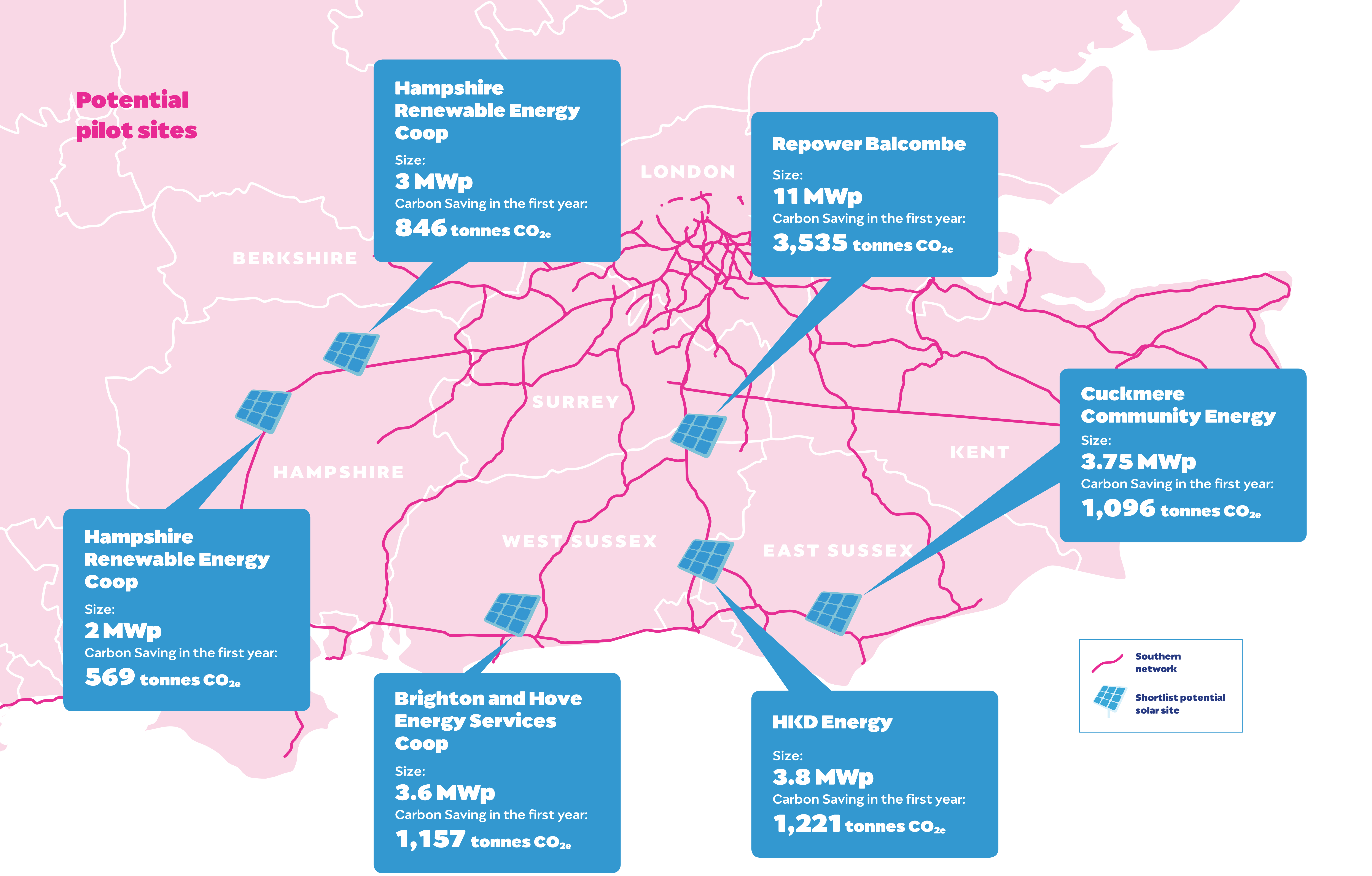


Thankfully, early in 2018 our technical team, working closely with Network Rail engineers, identified a pragmatic alternative solution. This was to connect into the 33kV ac feeder systems that carry power from the grid supply points (GSPs) to the substations. This approach will lead to some dc-ac-dc conversion losses, but it has a number of practical advantages over dc-dc supply to the substation:

1. Equipment for connecting solar farms to high voltage ac networks is very well established and widely available on the mass market. Therefore the task we face is to test and repurpose existing, highly mature technology (usually used for something else) for deployment on the railways. This avoids the need to develop a bespoke new power electronics interface from scratch.
2. Connecting to the feeders goes some way towards overcoming the major technical challenge for solar traction power: intermittency. This is because each GSP supplies around ten to fifteen substations, so the load that is being met is shared across all of these, making it much less peaky than it is at a single substation. It may also be possible to export small amounts of surplus power from the feeders back onto the grid via the GSP.
3. This approach should largely negate challenges around possible dc voltage range exceedances on the tracks, and negate the potential for power quality issues on the dc supplies, which would have substantially increased operational risk.

We can't reveal more about the technical solution we have arrived at now due to commercial considerations, but watch this space...

Potential pilot sites



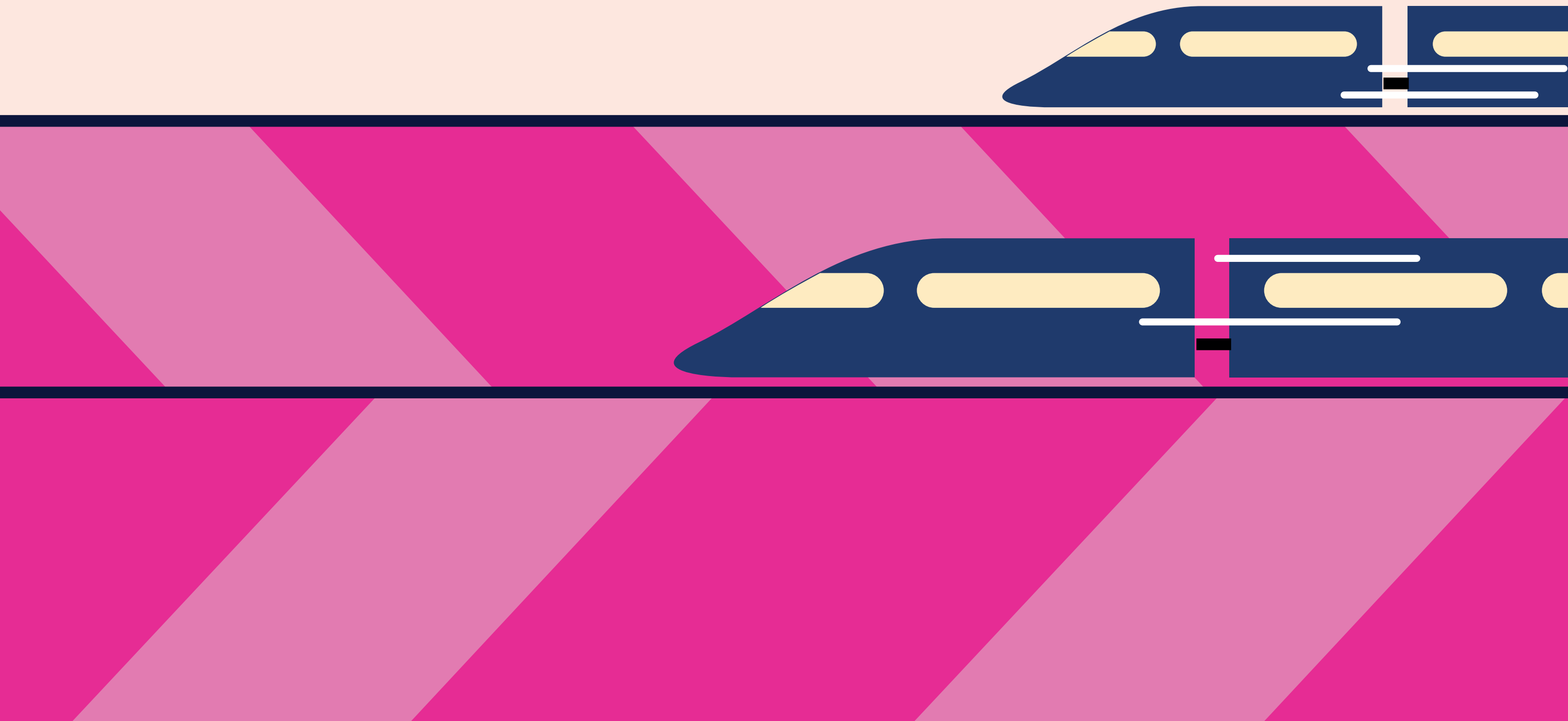
Next Stops

In January 2019, the Riding Sunbeams consortium was lucky enough to win funding under the Department for Transport and Innovate UK's First of a Kind competition. The competition was for real-world demonstrations of innovations to help decarbonise the railways. With this funding we will be able to test our technical solutions in the real world – on an operational railway. We will also be able to finalise the innovative commercial delivery model and power purchase agreements which we will need to realise our vision.

All being well, in summer 2019 Riding Sunbeams will connect the first ever solar traction array to the railway line between London and Weymouth. Our 30kWp 'First Light' demonstrator PV array will connect to an ancillary transformer on the traction system to supply power to lights and signalling equipment. We will then use real world performance data from our test unit to build and validate sophisticated modelling for much larger volumes of solar power to be injected directly into the dc traction network.

If successful, this 'Riding Sunbeams: First Light' project will prove that direct solar PV supply can be successfully integrated into UK railways without negatively impacting on rail operations or safety. It will also establish the business case and contractual relationships needed to unlock the opportunities our work will create for community energy groups and other renewable generators. By 2020, we hope to be in a position to help build and connect the world's first ever full-scale, community- and commuter-owned solar traction farm to the railways.

Get on board – here comes the sun!



Acknowledgements

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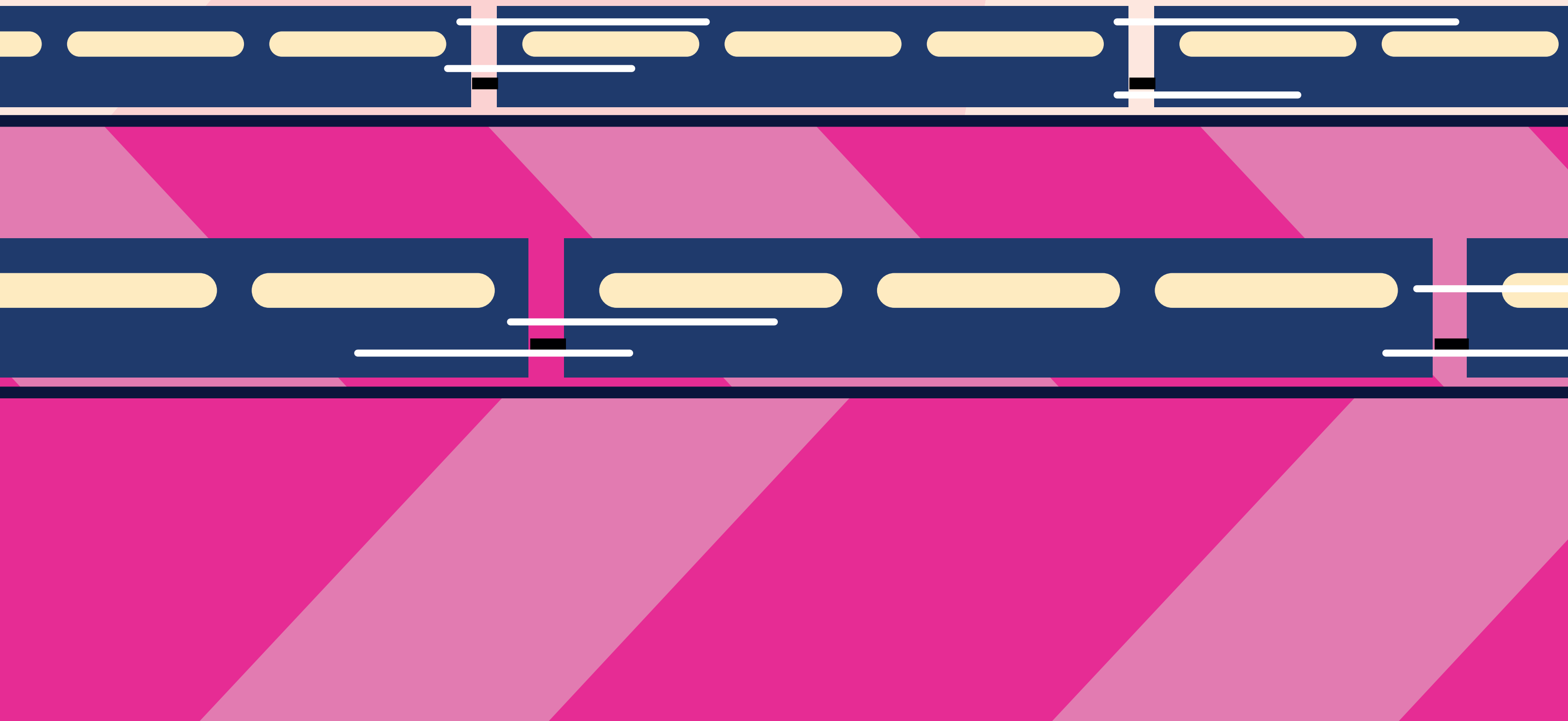


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