TRANSITION & PROJECT LEO

Market Trials Report (Period 2)

November 2022

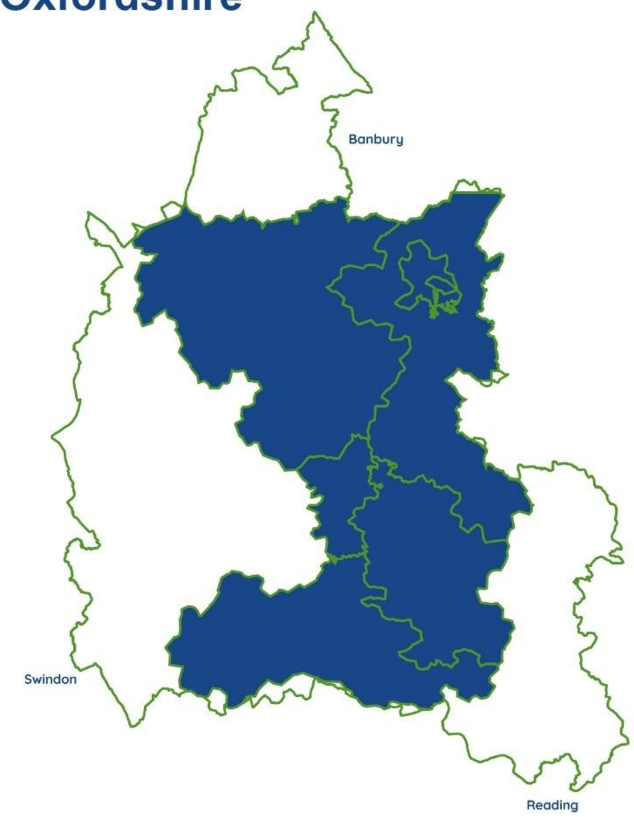
transition
Moving to a smart future

LEO
Local Energy Oxfordshire

Our flexibility market trials are;

- Being run in areas across Oxfordshire
- A unique collaborative programme of trials bringing two key energy innovation projects together
- Trialling new innovative markets and commercial approaches, smart systems and platforms in a real world environment
- Running across 7 bulk supply points and 13 primary sub stations areas
- Open to businesses across the trial areas able to offer flexibility services
- Unique opportunities for peers to trade spare connection capacities between each other

Oxfordshire



Executive Summary

The UK government is committed to decarbonising the electricity sector by 2035, with the Smart Systems and Flexibility Plans calling for 13GW of flexibility on the system by 2030[1]. Networks will be a key enabler of the net zero transition. In December 2021 all DNOs submitted their investment plans for ED2 (the period from 2023-2028). They committed to taking a flexibility first approach, with an aim to defer traditional network reinforcement through flexibility services and flexible connections. For example, SSEN's ambition is to defer up to £46m of reinforcement and procure 5GW of flexibility (including flexible connections) over the five-year period[2]. Flexibility will be a key tool at the networks' disposal to deliver on the significant volume of load related work required in ED2 and a vital tool whilst DNOs mobilise and deliver this work.

Ofgem is in the process of implementing "Access SCR" which will change the connection boundary for stakeholders connecting to the network, reducing the cost of connections. Whilst the resulting customer behaviour is uncertain, the likely increase in connections volumes will also drive the need for new flexibility products and services.

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Within the context of this evolving net zero policy landscape, Project LEO (Local Energy Oxfordshire) and Project TRANSITION have been working to establish new flexibility markets operating on the distribution network.

Project LEO is a socio-technical innovation project which aims to demonstrate that a functioning Smart Local Energy Systems (SLES) in Oxfordshire can maximise economic, environmental, and social prosperity in the area whilst focussing on improving customer engagement in flexibility markets.

The aims of the TRANSITION project are to; inform the design requirements of a DSO-facilitated flexibility marketplace and network interface: to develop the roles, responsibilities and rules within the marketplace and implement; and test these through a programme of trials in Oxfordshire.

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[1] https://www.gov.uk/government/publications/transitioning-to-a-net-zero-energy-system-smart-systems-and-flexibility-plan-2021

[2] https://ssenfuture.co.uk/

The two projects are conducting joint trials to maximise their outputs and learnings, bringing together the technical operation of a flexibility market based on network needs, and developing the “supply side” provision of services that either support the network (DSO-Procured) or improve the efficient use of existing capacity (DSO-Enabled) through customer and community engagement.

This report focuses on TP2 (Trial Period 2), building on the learnings from TP1[3] and informing the future scope of TP3 (the final trial period of the project). TP1 focused on mobilising the technology, markets and recruiting market participants. Through TP2, the focus has been increasing market participants' involvement (both traditional and non-traditional DERs (Distributed Energy Resources) and organisations) and gaining feedback on the variety of products and services available, including:

- Greater diversity of DSO-Procured services – four DSO-Procured services compared to two during TP1.
- Increased geographical coverage of the Trials – six Bulk Supply Points compared to three in TP1.
- Diversity of participating DER types – six DER types compared to two in TP1.
- Range of procurement horizons for services – three auction horizons (season-ahead, week-ahead and day-ahead) compared to one (week-ahead) in TP1.

The learnings from the trials will continue to inform the development of the networks' DSO functions as the start of the ED2 period approaches. The key learnings from TP2 are summarised as follows:

Load Related Expenditure (LRE) deferral: The analysis has been conducted using the same tools (e.g. the CEM) that DNOs used to develop their ED2 business plans. The trial has allowed an exploration of the relationships between market liquidity and flexibility prices, which will continue to inform the development of flexibility products and services at different levels of the network as the start of ED2 approaches. This will support significant DNO LRE deferral commitments and the use of flexibility in ED2.

Improving market accessibility for customers and communities: Feedback from TP2 suggests the number, complexity and length of the contractual arrangements still presents a barrier to participation and that some non-traditional market actors struggle to quantify and enable their flexibility and determine the benefits. This will continue to be explored in TP3, including workshops on the role of market rules to facilitate market access to reduce barriers to entry as much as possible. In addition, there are a number of community flexibility developments that will inform how this will develop going forwards. This work aligns with the enhanced DNO commitments to support vulnerable customers and communities as part of their ED2 plans, this includes enabling all customers and communities to benefit from the energy system transition. This may include using an aggregator who will manage market risks whilst providing market access.

[3] Ofgem-Report-Trial-Period-1.pdf (ssen-transition.com)

Increasing market liquidity: Initial findings from TP2 indicate the commercial benefits of participating in the trials are low, with high upfront costs required to enable DERs. However, this is not uncommon for innovation projects, which often require high initial investments for the social and environmental, and eventually commercial benefits to materialise. Furthermore, familiarity, automation and a commercial market with more market participants would substantially reduce costs and change the economics of participation. In TP3, the projects should explore flexibility as an addition to, rather than the basis for, the benefits of utilising DERs; ensuring that service providers obtain as fair a price as possible for their participation and there is an exploration of what a fair price for the benefits delivered to all market actors and GB. Linked to the above findings on improving market accessibility, increasing market liquidity at all voltage levels will be key to delivering the level of flexibility required to meet the networks' ED2 commitments and enable the broader net zero transition.

Trialling types of flexibility services and dispatch of DERs: Early data from the TP2 trials suggest that the week-ahead auctions are preferable to all DER types as they represent a balance between risk and effort. Whilst this data is informed by smaller market participants as represented by the stakeholders in LEO, these insights can support the development of the "menu" of flexibility products to be used in ED2.

The trial has also explored the risk of non-delivery of flexibility, which will be key to building networks' confidence in deploying flexibility at scale and assessing the reliability of responses. From a reliability perspective, initial results suggest partial delivery could be an easier phenomena for a network operator to manage, with modest amounts of over-procurement proving to be relatively effective. In TP2, the fulfilment of the requested capacity was low across all service types and initial data has shown that battery and solar PV installations have the lowest risk of under-delivery. However, the trials continue to show that the baselining approaches used are not appropriate for all DER types, making it difficult for all market participants to forecast their flexibility and thereby perform against the metrics provided in this report. Baselining will continue to be explored in TP3 to assess alternative methodologies and inform how networks will monitor and pay for flexibility at scale.

LV network modelling: Improving network visibility at lower voltages will be critical to all DNOs in ED2, and networks will report to Ofgem on their levels of coverage. The modelling work of TP2 has resulted in a detailed LV model for Osney Smart and Fair Neighbourhood (SFN) in central Oxford. The effect of a real-time forecast (using an offset) for Rose Hill primary gives a view of the significant voltage drop / increase across various LV feeders in the area, due to the long feeders and rooftop PV output. This indicates the challenges facing local SFN areas and the future value of automated and precise LV modelling methods and capabilities. In addition to this work, further work will be undertaken to determine the value of network monitoring to detect and quantify the level of flexibility services that are or can be delivered. These learnings will continue to inform the development and scaling of LV network modelling for networks into ED2.

Improving network utilisation, whole systems and LAEPs (Local Area Energy Plans): In ED2 networks will be measured and report to Ofgem on network utilisation. To deliver on net zero targets, network utilisation will need to increase compared to current levels, and flexibility (in particular services such as capacity trading) will be key enablers. The roles of different stakeholders in the development of LAEPs have been explored through TP2 to understand the current challenges and potential solutions. Initial feedback suggests that local authorities, followed closely by DNOs, are seen by most market participants as leading the implementation of the Local Area Energy Plans. As yet, there is no explicit mandate nor roadmap with specific skill needs. These insights will be important to all stakeholders in the ED2 period, as networks need to comply with new whole system licence obligations.

This has been recognised through project TRANSITION and LEO and likely requires further exploration. As a result, a consortium of TRANSITION and LEO partners are in the initial scoping phase for a LEO2 project which will explore the development of a LAEP at neighbourhood level to enable “Futurefit” homes and communities to achieve decarbonisation. This will include the development of options for the coordination and delivery of these plans at a local level: trialling LV network optimisation and capacity trading products as tools to increase network utilisation.

Relevance to future DSO market roles: Ofgem is yet to decide on the future structural arrangements for DSOs and this decision is anticipated early on in ED2. As a result, during TP2 the projects tested the different DSO market roles and explored the interactions of four market actors with these different roles in a workshop environment. This highlighted the DSO’s key responsibilities to ensure a fair and transparent marketplace and provide effective signals to flexibility providers (Market Facilitation) whilst ensuring the reliability, security and stability of local networks when instructing the delivery of flexibility services (Real-time Operation). These learnings will be applicable to any future path following Ofgem’s decision on DSO.

This report gives a flavour of the challenges overcome developing the local market for flexibility in the Oxfordshire area. In the final trial period (TP3), the projects will continue to increase market participation and engagement to gain further feedback on market participants and DERs’ ability to meet networks’ needs through the trialling of alternative flexibility products and services.

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1 Introduction

Based on the outputs of the ON-P, TRANSITION's aim is to inform the design requirements of a DSO market and network interface, develop the roles and responsibilities within the marketplace, develop the market rules and implement and test these by means of a programme of trials in Oxfordshire.

Project LEO (Local Energy Oxfordshire) is an important step in understanding how new markets can work from a market participant perspective and will demonstrate a county-wide Smart Local Energy System (SLES) to maximise economic, environmental, and social prosperity for the region.

The TRANSITION project approach is to explore the technological and market solutions and identify issues that need to be addressed in relation to the energy transition. The LEO project takes that technical and market knowledge and adds the people and academic insight to the same issues, allowing for a much greater and holistic learning about the whole system in a real commercial and behavioural environment.

Project LEO and Project TRANSITION are conducting joint trials to maximise the outputs from testing and developing local flexibility markets in Oxfordshire during three Trial Periods[4]. The location for this trial period includes six individual areas with 99 devices monitoring the low voltage network for Distributed Energy Resources (DERs), these are mapped in Figure 1.

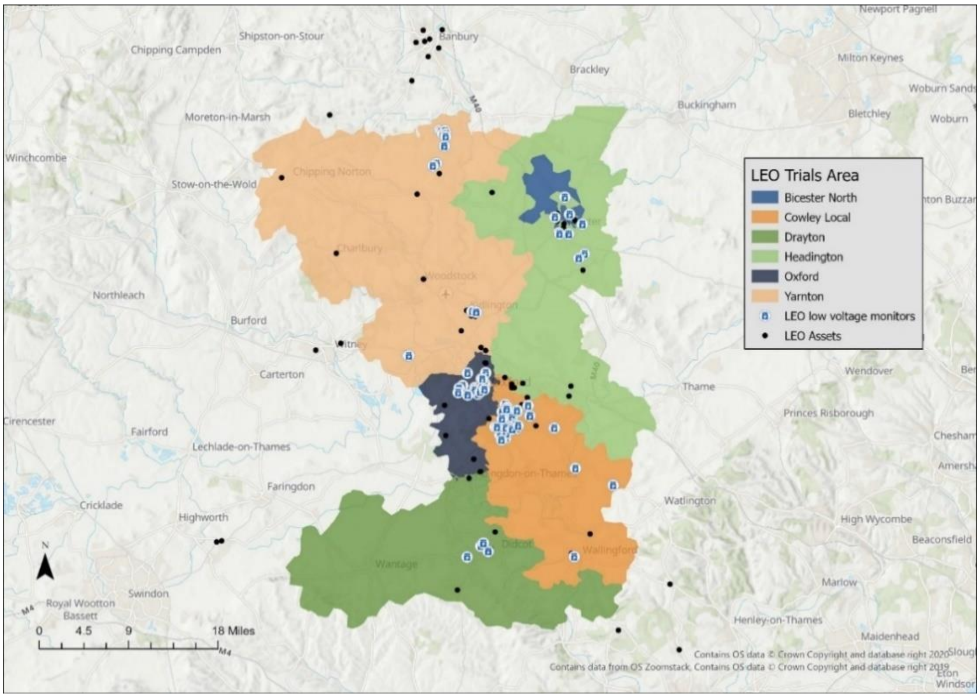


Figure 1: LEO trial area, installed monitoring and DERs

[4] Trials Plan version 3, published by LEO and TRANSITION February 2021; TP1 (Nov-21 to Feb-22), TP2 (May-22 to Sep-22), and TP3 (Nov-22 to Feb-23)

Trial period data has been collected from the market platforms and the following sources:

- monitors on the low voltage network installed within the trial area (see Figure 1);
- metering at site level where DERs are installed;
- metering directly connected to the DER; and
- participants during the trials and during formal feedback sessions.

As summarised in Table 1 the trials delivered during Trial Period 2 (TP2) were an advancement of those delivered in Trial Period 1 (TP1). Through TP2, the focus has been increasing market participants' involvement, gaining feedback on the variety of products and services available, increasing geographical coverage of the trials, increasing the diversity of participating DER types and range of procurement horizons for services. TP2 ran for 20 weeks from 2 May 2022 to 16 September 2022.

Table 1: Summary of changes in TP2 compared to TP1

Area	During TP2	During TP1
DSO-Procured Services	Sustain Peak Management (SPM), Sustain Export Peak Management (SEPM), Dynamic Constraint Management (DSM) and Secure Constraint Management (SCM)	SPM
DSO-Enabled Services	Maximum Export Capacity (MEC) and Maximum Import Capacity (MIC)	MEC and MIC (offline)
Geographical Coverage	6 Bulk Supply Points (BSPs) - Bicester North, Cowley Local, Oxford, Drayton, Headington and Witney-Yarnton	3 BSPs - Bicester North, Cowley Local and Oxford
Participating DER Types	Batteries, Electric Vehicles (EV) which use smart charging, EV to Grid (V2G), solar PV, hydro and Demand Side Response (DSR)	Battery and (V2G), hydro and solar PV
Products (procurement timeline)	Season, Week and Day Ahead	Week Ahead
Service windows	DSO-Procured: 0000 - 2400[5] DSO-Enabled: 0000 - 2400	DSO-Procured: 1500-1900 DSO-Enabled: 0000 - 2400
Scheduled/Forecast	Scheduled	Scheduled
Service Days	Mon – Sun	Mon – Sun
Total Auctions	DSO-Procured:116 DSO-Enabled: 8	DSO-Procured: 41 DSO-Enabled: 7
Total Events	DSO-Procured:93 DSO-Enabled: 2 (no physical delivery)	DSO-Procured: 69 DSO-Enabled: 4 (no physical delivery)

[5] Five service windows covered a 24hr period, service windows for each service are shown in Table 2

The joint approach to trials identified six flexibility services to be delivered that either support the network (DSO-Procured) or improve the efficient use of existing capacity (DSO-Enabled). A description is provided below, Table 2, with a full description of each service provided on the LEO website[6].

The trial plan also detailed the planned auctions and delivery events for DSO-Procured service and DSO-Enabled service, using a variety of contracts and how buyers and sellers would interact with the market (Neutral Market Facilitator (NMF), Piclo, or offline) with increased complexity as the trials progressed.

Table 2: Summary of DSO-Procured and DSO-Enabled Services

Service	Description of Service
DSO Procured Services	
Sustain Peak Management (SPM)	A market participant delivers flexibility to the DSO to reduce the demand on a critical DNO asset (such as a transformer) that is forecast to become overloaded due to increased demand.
Sustain Export Peak Management (SEPM)	A market participant delivers flexibility to the DSO to increase the demand on a critical DNO asset (such as a transformer) when it is forecast to become overloaded due to increased generation.
Secure DSO Constraint Management (pre-fault) (SCM)– **new**	A market participant delivers flexibility to the DSO to reduce the demand on a critical DNO asset (such as a transformer) that is subject to an emerging issue that could result in an unplanned outage if not addressed.
Dynamic DSO Constraint Management (post-fault) (DCM) – **new**	A market participant delivers flexibility to the DSO after an unplanned outage to help restore electricity to a network area or relieve pressure on the system so it can recover.
DSO Enabled Services	
Maximum Export Capacity (MEC)	Two market participants in a network area with limited (or no) spare export capacity trade a portion of their export capacity for an agreed period, without affecting the network. The Buyer can increase their export level, but the Seller must reduce their export level.
Maximum Import Capacity (MIC) – **new**	Two market participants in a network area with limited (or no) spare import capacity trade a portion of their import capacity for an agreed period without affecting the network. The Buyer can increase their import level, but the Seller must reduce their import level.

Following recommendations from TP1, the price ceiling was increased across all services with the aim of increasing competition, liquidity and reliability in the market as illustrated in Table 3. The change in prices was based on the DSO “Willingness to Pay” (prices offered by the DSO during TP1 auctions) and potential participants’ “Willingness to Accept” (based on comparable services from Oct-21 to March-22). SEPM included an “opportunity cost” to reflect the lost income for reduced export of generation, or the increased cost of demand upon delivery of this service.

[6] Understanding flexibility services - Project LEO (project-leo.co.uk)

Table 3: Service price ceiling in TP1 and TP2

DSO service	TP2 service price ceiling	TP1 service price ceiling[7]
SPM	£600 / MWh	£300 / MWh
SEPM	£850 / MWh	£300 / MWh
SCM	£800 / MWh	£400 / MWh
DCM	£1,200 / MWh	£500 / MWh

The key achievements associated with TP2 are described in detail throughout this report but are captured in Figure 2 below.

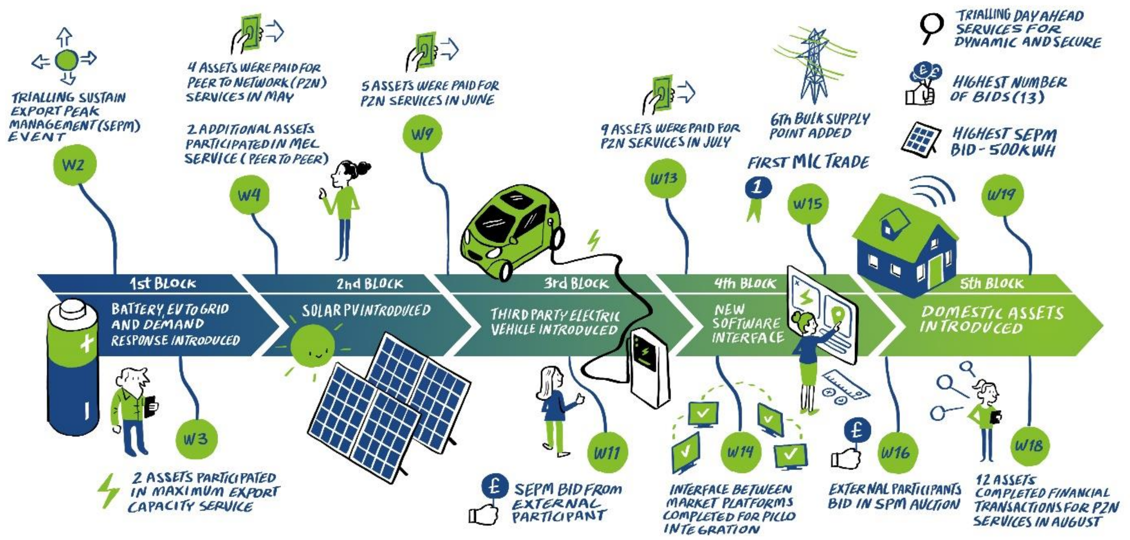


Figure 2: TP2 key achievement

In parallel with the trials in Oxfordshire, SSEN and project partner Electricity North West Limited (ENWL) conducted a set of simulated trials covering parts of the Greater Manchester network. These simulations allow the project to explore aspects of flexibility that would not be possible within the physical trials, such as emergency operating conditions or the impact of the mass adoption of low carbon technologies. Initial activities tested interoperability of various IT systems and power systems modelling software platforms.

The learnings and recommendations from this report will inform the development of the Local Flexibility Market, and the development of the networks' DSO functions as the start of ED2 approaches, as well as informing the detailed approach for future trial periods to maximise project outcomes. This will allow TRANSITION to continue to provide ongoing feedback to and inform the Energy Networks Association Open Networks project (ON-P).

7 Although not used in TP1, the prices for the SEPM, SCM and DCM service were advertised prior to TP1

This report focuses on the TP2 and fulfils TRANSITION Ofgem Project Direction, Reference 7 (Trials Stage 2; Completion of second stage of Trials).

2 Routes to Market

Clearly defined, well understood and accessible routes to market are essential to enable participation in flexibility markets and in ensuring a just energy transition. TP2 involved the delivery of three additional DSO-Procured services (additional opportunity) and the addition of two new third-party market participants (indirect route to market via an aggregator who considers the commerciality of the services). These changes provided learnings with respect to informing the optimal market structure and how to engage with the wider market going forward.

2.1 Alignment of Services and Products

The increased number of services, procurement horizons and locations substantially increased the number of auctions in TP2, as shown in Table 4. This allowed the project to explore the alignment of services and products to different DER types, as discussed in the following subsections.

Table 4: Services and products procured in TP2 with number of auctions and resulting contracts.

Service	Product timeline					
	Season-ahead[8]		Week-ahead		Day-ahead	
	Auctions	Contracts	Auctions	Contracts	Auctions	Contracts
Sustain Peak Management (SPM)	6	0	34	26	3	0
Sustain Export Peak Management (SEPM)			49	52	12	3
Dynamic Constraint Management (DCM)					9	6
Secure Constraint Management (SCM)					3	5
Trading Export Capacity (Exceeding MEC)	2	2				
Trading Import Capacity (Exceeding MIC)	6	0				

2.1.1 Summary of the SPM auctions

The purpose of the SPM service is to provide flexibility to counter a forecast increase in demand on a DNO asset to prevent it from being overloaded, typically during winter tea-time. Procurement horizons reflect the magnitude and likelihood of constraints on season-ahead (20 weeks), week-ahead and day-ahead time horizons. SPM auctions in TP2 were held across multiple time horizons to encourage market

[8] There was no interest in these auctions, so not offered capacity or Delivered Capacity.

participants to submit offers for all product timelines. There is no perceived loss of value as all auctions get paid the same price. Discussions with market participants during TP2 revealed that those with predictable DERs preferred allocating all capacity to one time horizon as it reduces effort and is more cost effective. The following observations emerged with respect to the different time horizons:

- There were no contracts for the season-ahead as this requires long-term predictability and may get higher prices from the other time horizons.
- There were no contracts for the day-ahead as it required too much effort despite the highest certainty of delivery.
- The week-ahead auctions were of interest for DERs that have short-term reliability, even if dependant on weather forecasts, and provided the opportunity to experiment with different pricing strategies.

Of the 43 planned SPM auctions, 18 week-ahead auctions had at least one accepted response capacity. Table 5 summarises these 18 auctions by DER type and location.

Table 5: Summary for all Sustain Peak Management auctions in TP2

Substation ID	Completed Auctions	Aggregate requested capacity (kW)	Aggregated of offered capacity (kW)				Number of accepted offers (week-ahead)				Aggregated delivered response (kWh)			
			DSR	Battery	V2G[9]	EV[10]	DSR	Battery	V2G	EV	DSR	Battery	V2G	EV
A	9	515.6	-	160	10.8	6	-	9	3	1	-	181	41.8	5.18
E	1	100	-	-	-	7	-	-	-	1	-	-	-	3.77
C	8	323.8	202	-	10.8	2	5	-	6	1	183	-	10	6.48
Total	**18**	**939.4**	**202**	**160**	**21.6**	**15**	**5**	**9**	**9**	**3**	**183**	**181**	**51.8**	**15.40**

The 18 successful SPM week-ahead auctions resulted in 25 accepted offers with an aggregate of 939.4kW of requested capacity across three substations. The total offered capacity submitted was 398.6 kW (42.4% of requested capacity) from four DER types across 26 accepted offers. The delivered volume was 431.2kWh (108.2% of accepted offers). Delivered capacity varied from 130% over-delivery (DSR) to 0% delivery (across all DER Types), with actively increasing demand counter to system requirements (EV and V2G portfolios), due to availability of vehicles and potential effect of baselining methodology (see Section 3). The geographical spread of the DERs meant the number of available DER types varied between substations, impacting the market liquidity.

[9] V2G chargers require the EV to be plugged in and then be used to charge or discharge the EV battery at a variable rate.
[10] EVs require the EV to be plugged in and do not have a V2G but can be switched on or off at the charging rate.

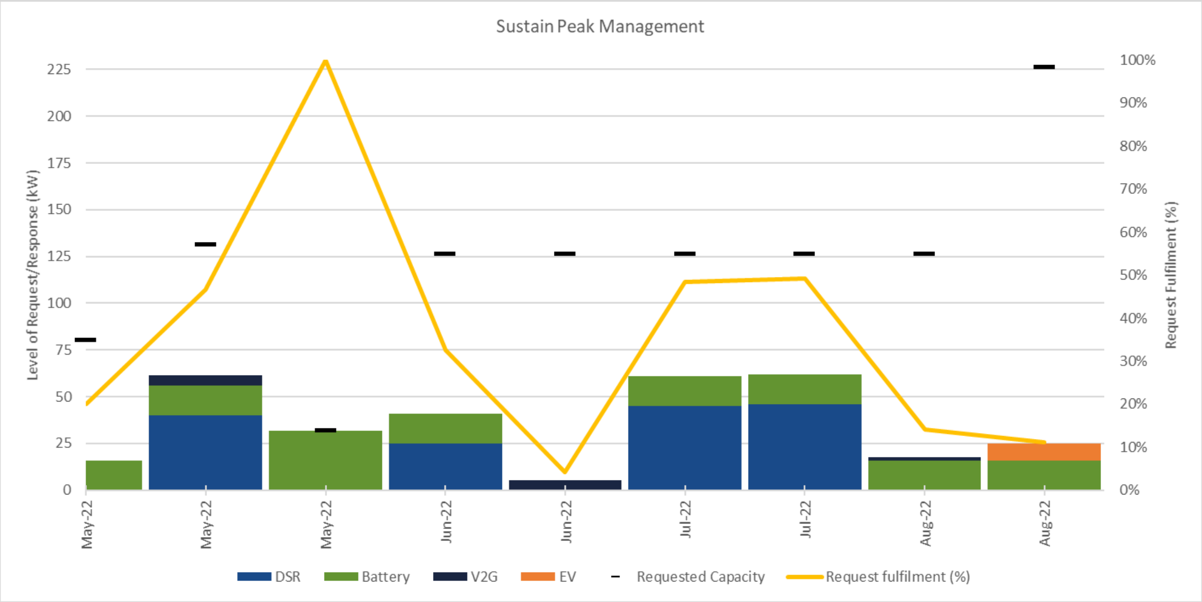


Figure 3: Response by DER type against requested capacity (with % of request fulfilment) for SPM.

Figure 3 provides an overview of SPM auctions and considers the offered capacity, the requested capacity and the proportion of the requested capacity that was met by the offered capacity (request fulfilment).

The requested capacity was varied between auctions to replicate the variable nature of DSO needs and to test the response of market participants. Only one auction had the offered capacity equal to the requested capacity; in all other auctions, the offered capacity provided less than 50% of the requested capacity. As shown in Figure 3, the majority DER for four auctions was DSR which is highly dependent on environmental conditions and resulted in a variable level of delivered response.

Price variation

To encourage greater liquidity, the maximum Total Contract Value (TCV)[11] for SPM in TP2 was increased from £300/MWh in TP1 to £600/MWh. Despite the increased TCV, there was only one auction where the offered capacity equalled the requested capacity. The other auctions were illiquid, as there was insufficient offered capacity and prices were predominantly at or near the maximum TCV. There were two auctions above the TCV: one was rejected as it exceeded the TCV and the other was subsequently accepted as it was clearly human error.

The combination of availability and utilisation prices for all SPM auctions are provided in *Figure 4*. For additional learning, the SPM service window was changed from 4-hours to 2-hours for three auctions to see how market participants behaviour varied. The capacity offers and outcomes are plotted in *Figure 4*. Each point has the number of capacity offers submitted for an availability / utilisation combination for a particular service window, e.g. 1 (4h). For a 4-hour service window, there are 24 week-ahead

[11] A Capacity Offer for an auction has an Availability Price and a Utilisation Price. The TCV calculation for an auction is the (Availability Price * service hours from the auction) + (Utilisation Price * expected hours of use in the auction). The TCV is compared to the price cap and does not usually exceed it.

contracts (one above price ceiling, 21 at price ceiling and two rejected) and one day-ahead contract at the price ceiling. For a 2-hour service window there are three week-ahead contracts (two under the price ceiling and one at the price ceiling). Overall, the offered capacity was at the price ceiling, with greater emphasis on the utilisation price.

Figure 4: Utilisation Price vs Availability Price for Sustain Peak Management

2.1.2 Summary of the SEPM auctions

The purpose of the SEPM service is to provide flexibility to counter a forecast increase in generation on a DNO asset to prevent it from being overloaded, typically on a summer early morning or afternoon. The new SEPM Service was procured for six BSPs for week-ahead and day-ahead. The type of DERs participating included solar PV, which was a significant proportion of the offered capacity (64.4%). The summary of the SEPM auctions and the resulting contracts are presented in Table 6.

Table 6: Summary for all Sustain Export Peak Management auctions in TP2 (indicates day-ahead auctions)*

Substation ID	Completed Auctions	Total capacity requested (kW)	Total capacity offered (kW)					Number of accepted offers					Total Response Delivered (kWh)				
			DSR	Battery	V2G	EV	PV	DSR	Battery	V2G	EV	PV	DSR	Battery	V2G	EV	PV
B	7	168	-	-	30	-	24	-	-	6	-	1	-	-	75.4	-	27.4
A	11	1100	-	111	25	35	110	-	10	3	3	6	-	445	48.8	53.4	184
A*	1	24	-	5	-	-	-	-	1	-	-	-	-	2.3	-	-	-
E	1	100	-	-	-	33	-	-	-	-	1	-	-	-	-	13.4	-
D	3	800	-	-	-	-	528	-	-	-	-	4	-	-	-	-	1072

Substation ID	Completed Auctions	Total capacity requested (kW)	Total capacity offered (kW)					Number of accepted offers					Total Response Delivered (kWh)				
			DSR	Battery	V2G	EV	PV	DSR	Battery	V2G	EV	PV	DSR	Battery	V2G	EV	PV
C	8	368	91.3	-	35	-	-	5	-	7	-	-	217	-	51.0	6.6	-
F	4	400	-	-	-	24	40	-	-	-	1	5	-	-	-	11.2	70.7
F*	2	200					10					2	-	-	-	-	
Total	**37**	**3160**	**91.3**	**116**	**90**	**92**	**712**	**5**	**11**	**16**	**5**	**18**	**217**	**447.3**	**175**	**84.6**	**1354**

There were 37 SEPM week-ahead auctions held for an aggregate of 3,160kW of requested capacity across six substations. The total offered capacity submitted was 1,106.3kW (35% of requested capacity) from five DER types across 55 accepted offers. The delivered volume was 2,275.9kWh (205.7% of accepted offers) with measured DER delivery varying from 362% over-delivery (baselining effects on solar PV DERs) to 0% delivery and actively reducing demand counter to the system requirements (EV, V2G and DSR). As with SPM, the fulfilment of the requested capacity is low; one auction had 60% but the remaining auctions varied from 5% to 40%, as shown in Table 6.

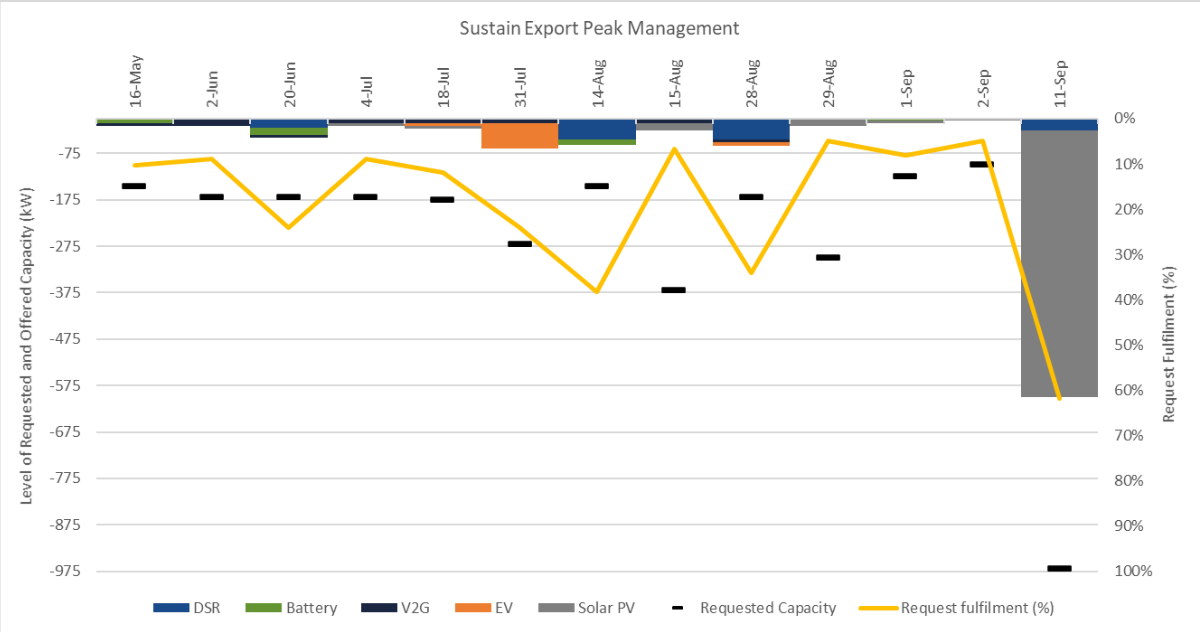


Figure 5: Response by DER type against requested capacity (with % of request fulfilment) for SEPM.

Price variation

SEPM is a new service and the DSO priced it with a price cap of £850/MWh. Market participants were uncertain how to balance the availability and utilisation prices for offered capacity within this higher

TCV. Some market participants priced below the TCV whilst others regularly priced over the TCV (these were mostly rejected by the DSO, however some were accepted). The TCV was held constant for all SEPM auctions and all but one SEPM auction had a 4-hour service window. The SEPM auction held on 11 September had a 14-hour service window and this increased the number of market participants, as there was significantly more solar PV market participants than any other DSR. The combination of availability and utilisation prices for all SEPM auctions are provided in Figure 6. For the 4-hour service window, there are 46 data points (none above price ceiling, 26 at price ceiling, 15 below price ceiling and five rejected) whilst for a 14-hour service window there are 13 data points (four above price ceiling, four at price ceiling, three below price ceiling and two rejected). In general, market participants have bid under the TCV at a higher rate than in the SPM auctions. Furthermore, market participants have shown more variation in bidding strategy, with significantly more spread compared to SPM auctions. For the longer service windows offered by the SEPM auction, there has been a more defined strategy of opting for higher availability prices compared to utilisation prices. This is all illustrated in Figure 6.

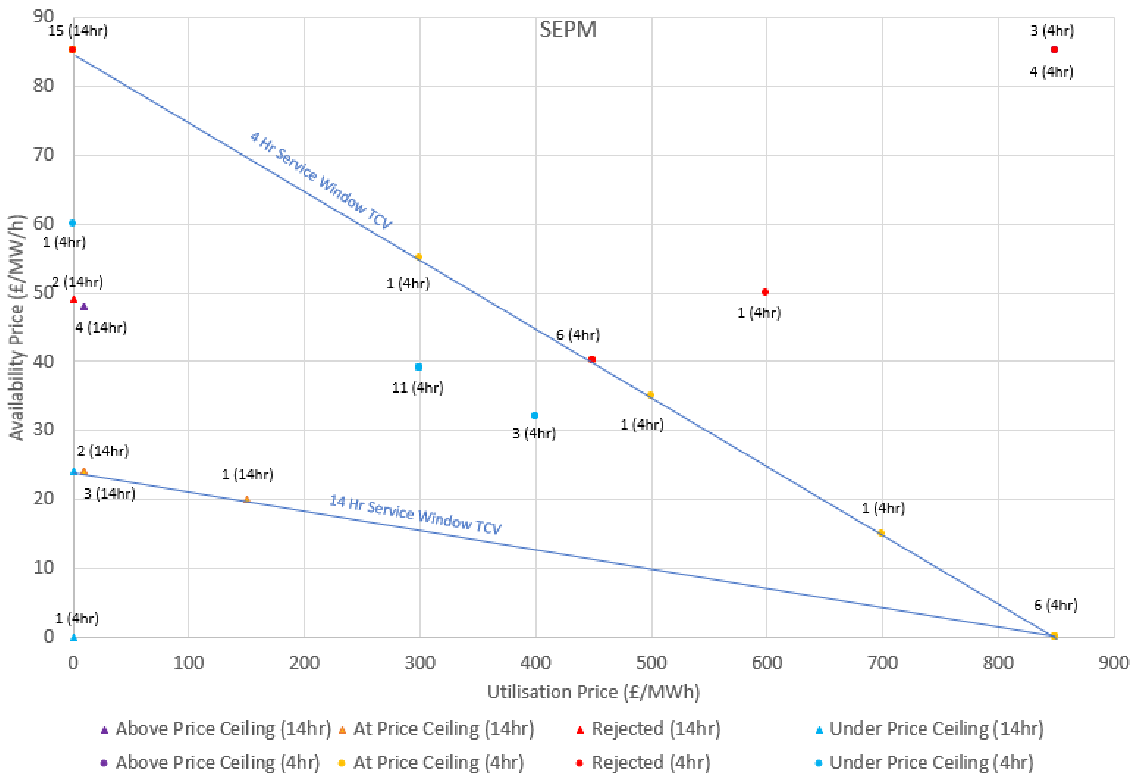


Figure 6: Utilisation Price vs Availability Price for SEPM

2.1.3 Summary of the Secure Constraint Management auctions

SCM was procured for three BSPs through three day-ahead auctions. Only DSR and batteries participated, as only they could respond quickly enough to deliver the service. The TCV for SCM was £800/MWh. A summary of the SCM auctions and the accepted offers are presented in Table 7.

Table 7: Summary of Secure Constraint Management auctions in TP2

Substation ID	Completed Auctions	Aggregate capacity requested (kW)	Aggregated capacity offered (kW)		Number of accepted offers (day ahead)		Aggregated Capacity Delivered (kWh)	
			DSR	Battery	DSR	Battery	DSR	Battery
A	1	100	-	10	-	1	-	13.5
E	1	100	0.424	-	2	-	0.06	-
C	1	50	1.75	-	2	-	0.11	-
Total	3	250	2.174	10	4	1	0.17	13.5

There were three SCM day-ahead auctions held for an aggerate of 250kW of requested capacity across three substations. The total offered capacity submitted was 12.174kW (4.8% of requested capacity) from two DER types, across five accepted offers. The delivered volume was 13.67kWh (110.9% of accepted offers), with delivered capacity varying from 35% over-delivery (battery) to 0% delivery. DSR was particularly unsuccessful in reducing demand in response to this service with all DSR services delivered capacity being 0% of offered capacity. As with SPM and SEPM, the fulfilment of the requested capacity is low, as shown in Table 7.

Price variation

As illustrated in Table 8, all five accepted offers had the same availability price and only the battery had a (low) non-zero utilisation price.

Table 8: Accepted contracts for the SCM auctions

DER Type	Availability Price (£/MW/h)	Utilisation Price (£/MWh)	TCV (£/MWh)	Ceiling TCV (£/MWh)
Battery	33	8	800	800
DSR	33	0	790	800
DSR	33	0	790	800
DSR	33	0	790	800
DSR	33	0	790	800

2.1.4 Summary of the Dynamic Constraint Management auctions

The purpose of the DCM service is to provide flexibility to restore the network back to normal, following an unplanned outage of a DNO asset. This service could be required at any time, depending on network conditions. DCM could be required at any time and has the shortest notice period of the DSO-Procured services. DCM was procured for three BSPs through four day-ahead auctions. Only DSR and batteries participated as only they could respond quickly enough to deliver the service. The TCV for SCM was £1,200/MWh. A summary of the DCM auctions and the accepted offers are presented in Table 9.

Table 9: Summary of Dynamic Constraint Management auctions in TP2

Substation ID	Completed Auctions	Total capacity requested (kW)	Total capacity offered (kW)		Number of contracts (day ahead)		Total Response Delivered (kWh)	
			DSR	Battery	DSR	Battery	DSR	Battery
A	2	200	-	32	-	2	-	25.5
E	1	100	0.27	-	2	-	0.26	-
C	1	50	25.1	-	2	-	1.08	-
Total	**4**	**350**	**25.37**	**32**	**4**	**2**	**1.34**	**25.5**

There were four DCM day-ahead auctions held for an aggregate of 350kW of requested capacity across three substations. The total offered capacity submitted was 57.37kW (16.4% of requested capacity) from two DER types across six accepted offers. The delivered volume was 26.84kWh (110.9% of accepted offers), with delivered capacity varying from 59% over-delivery to 0% delivered capacity, due to the unreliability of a low number of small-size DERs in the delivery portfolios. Improved success is expected in TP3 as there is a wider DER base with a more accurate baseline. As with SPM, SEPM and SCM, the fulfilment of the requested capacity is low, and most of the capacity is offered by battery, as shown in Figure 7.

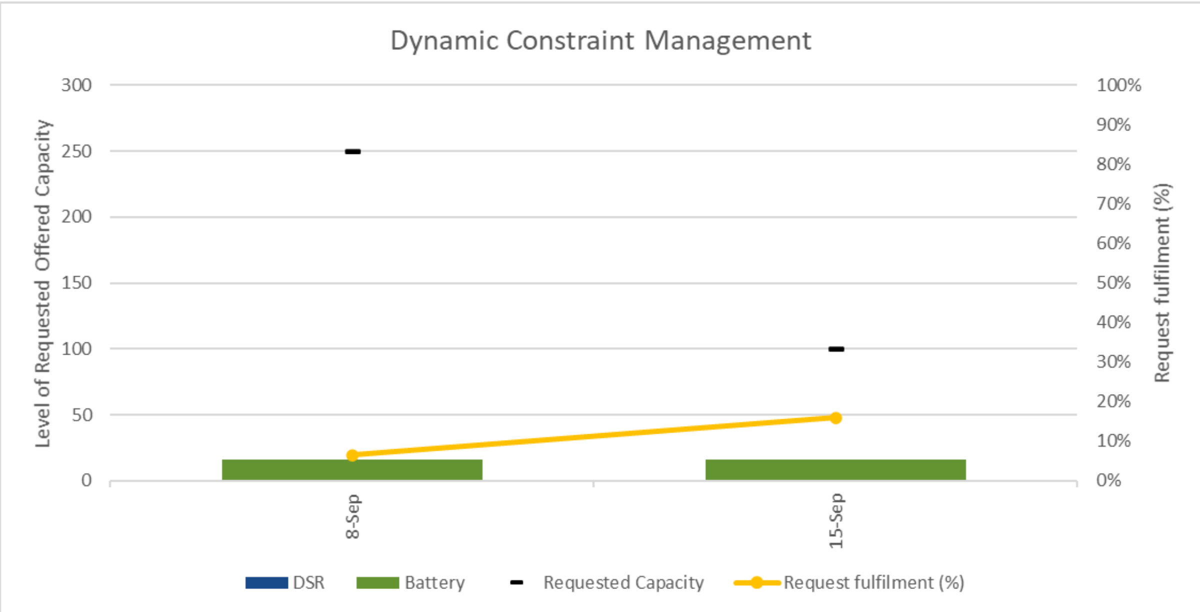


Figure 7: Response by DER type against requested capacity (with % of request fulfilment) for DCM

Price variation

The DCM service is a utilisation price only service. Therefore, market participants were required to use the provided number of utilisations to ensure the overall price was within the TVC for the auction. During TP2, all responses to the DCM auctions were accepted. One of the auctions had no effective TCV applied, allowing participants to bid at any price to obtain learnings. All the bids for DCM are presented in Table 10.

Table 10: Accepted contracts for DCM auctions

DER Type	Availability Price (£/MWh)	Utilisation Price (£/MWh)	TCV (£/MWh)	Ceiling TCV (£/MWh)
DSR	0	1,200	1,200	1,200
DSR	0	1,200	1,200	1,200
DSR	0	1,200	1,200	1,200
DSR	0	1,200	1,200	1,200
Battery	0	1,200	1,200	1,200
Battery	0	1,500	1,500	9,999

When the TCV was capped, all accepted offers were at the price cap. When the cap increased to £9,999/MWh, the maximum utilisation price for an accepted offer was only £1,500/MWh (£300/MWh above the capped TCV), although it was expected to be much higher. This may be down to the type of organisations participating in the auctions, who adopt a more balanced view of the benefits rather than a hard commercial approach, and used the previous TCV as a guide.

2.1.5 Summary of the MIC/MEC trades

An important amount of learning was generated from numerous offline MIC and MEC trades in TP1. In TP2 however, the additional learning was limited to only two MEC auctions with accepted offers (see Table 11 and Table 12); the trades were speculative, as water conditions for the hydro power plant prevented generation above its existing MEC.

Additional MIC and MEC trades did not take place due to delays in the rollout of enablement equipment on sites, with the potential to utilise additional MEC, and the absence of trading partners with the ability to utilise additional MIC. The cumulative effect of the operational issues and lack of trading partners on the market meant that only two DSO-Enabled auctions were held for MEC trades, and neither involved the physical use of the additionally procured MEC.

Table 11: Summary of successful MEC auctions in TP2

Substation ID	Completed Auctions	Aggregate capacity requested (kW)	Aggregated capacity offered	Number of accepted offers	Aggregated capacity delivered (kWh)
			Hydro	Hydro	Hydro
A	2	40	40	2	0
Total	2	40	40	2	0

Table 12: Accepted MEC trades

Initiator DER Type	Response DER Type	Capacity Traded (kW)	Duration (hrs)	Availability Price (£/MW/h)	Utilisation Price (£/MWh)	TCV (£/MWh)
Hydro	Demand site with PV	-20	10	10	0	50
Hydro	Demand site with PV	-20	10	10	0	50

Market participants attempted to initiate MIC trades by creating four auctions, each to sell 20kVA of import capacity. No response was received because there were no suitable counterparties using the NMF at that time to buy additional MIC in the network areas with auctions. This DSO-Enabled service has not provided sufficient evidence of value generation to attract external market participants due to the lack of an evidence base and limited understanding of the service.

2.1.6 Key Learning and Recommendations for TP3

Table 13 Key learnings and recommendations on alignment of services and products

Key Learnings	Recommendations
Market participants who expect to participate in auctions for a service prefer week-ahead auctions as it avoids the workload of day ahead auctions and the long-term risks of season-ahead auctions.	Consider how services could be stacked over different time horizons and with other services to encourage participation. This may include increasing prices for auctions nearer delivery or weighting towards utilisation price only.
Need to encourage more DERs capable of delivering DCM and SCM to participate in the Trials and run more auctions for these services to understand how the tiered approach can work.	Discuss with BaU to determine what value the project can add to DCM and SCM, e.g. range of DERs, availability / utilisation price variations, and increased changes to the service window (and more auctions at each).
The availability of V2G chargers is affected by the unpredictable behaviour of the EV users which results in an unpredictable response. This issue does not appear to exist with the EVs not connected to a V2G charger.	Engage with market participant with V2Gs to explore how availability and performance can be improved. Engage with EVs not using V2G chargers to determine if there are behaviour improvements that would benefit the market participant with V2G.
Varying service windows had an effect on the availability / utilisation price balance but there was insufficient experience to draw any substantial conclusions.	Change the duration of service windows to determine if there is any correlation with pricing behaviour.
Across all DSO-Procured services, different DER types demonstrated occasions of over-delivery, under-delivery, and delivery in the opposite direction to the service need, which increased the network need for flexibility.	Gather further evidence of delivered capacity by DER type for a range of DSO-Procured services, conditions and approach by market participants.
Offered capacity in auctions was almost always less than the requested capacity, which meant there was low liquidity in the market and the price cap usually prevailed.	Discuss with BaU to determine what value the project can add, e.g. reduce the request capacity to near or below the available DERs to increase liquidity and create opportunities for learning from competitive bidding.

2.2 User Experience of Market Platforms

There were two platforms that provided a route to market for DSO-Procured and DSO-Enabled services: NMF and Piclo Flex. The NMF platform functions as a DSO-facilitated marketplace that operated as a centralised market for the procurement and delivery of DSO-Procured and DSO-Enabled services. The Piclo Flex platform operates as a satellite market that provides market participants with an alternative route to market for DSO-Procured services. Piclo Flex interacted with the NMF via the use of APIs (developed primarily during TP2) for the procurement of DSO-Procured services only, publishing capacity requests, collecting capacity offers and providing them to the NMF for evaluation, and relaying auction outcomes to market participants.

In terms of exploring the benefits of different routes to market, TP2 made significant progress gathering further experience of platform choices. TP2 also saw the direct integration of the People's Power Station DER control platform with the Piclo platform. This was commissioned in TP2 and will be evaluated during TP3 to see if it allows a more efficient operation of a market participant's portfolio of renewable DERs, as well as the opportunity for automating auction participation.

There were 103 auction responses for DSO-Procured services received by the NMF. Of these, 30 responses were from two market participants using the Piclo market; this may have been higher as one service was not initially available on the Piclo platform. This indicates a central-satellite market model can work for advertising DSO-Procured services. It is uncertain if this market model would work for DSO-Enabled services, as they were not trialled sufficiently during TP2 or on the Piclo platform. The NMF has a natural advantage as it can collate all offers of capacity and interact with the DSO systems to determine the effect on the network. However, if the central-satellite platform market model can be replicated, this provides more market access opportunities for market participants.

Feedback from users of the NMF and Piclo platforms can be summarised as follows:

- A standalone spreadsheet tool was developed to calculate the TCV and provide an indication of the availability and utilisation prices within the price caps for an auction. This created confusion for market participants, until the number of utilisations was published in advance; this is not BaU behaviour, but enabled additional market information to be collected.
- Users requested greater visibility of auction requests and their responses in auction feedback.
- Users requested an API from the platform or emails to be sent directly to market participants with details of dispatch instructions.
- Comparison of platform users found that:
    - two market participants preferred the Piclo Flex platform because it has a clear map, provides notifications that a DER can be used for a particular DSO-Procured service, and has an easy-to-use interface that allows market participants to edit existing bids.
    - market participants that preferred the NMF platform indicated the support received from SSEN whilst navigating the platform was one of the main draws.

2.2.1 Key Learning and Recommendations for TP3

Table 14: Key learnings and recommendations on user experience of market platforms

Key Learnings	Recommendations
A market model based on a central platform interacting automatically with a satellite platform (and vice versa) worked well for DSO-Procured services but is uncertain for DSO-Enabled services.	Ensure that the option of using the Piclo platform is highlighted to all market participants to increase utilisation, where possible.
The user experience of the platform can be improved to help ensure response and bids are correctly understood and responded to. Market platform needs to: be easy to use, have a clearly defined process, provide a map to show where auctions take place, be able to connect buyers and sellers (and allow them to communicate effectively) and provide an audit trail for transactions.	Ensure future developments for the user experience of the NMF platform are captured to progress into any business-as-usual platform. This includes automation across the end-to-end process, P2P settlement and verification process for all parties and include inbuilt methods to help users navigate and use the platform.
APIs enable easier market interaction, improve the experience for market participants with a large number of DERs in their portfolios, and enable automated dispatch of DERs by the market participant.	Review the use of APIs during TP3 to determine where these are required to lessen the burden on market participants.
The training was improved following feedback during TP1. This worked well for market participants and should be continued prior to and during TP3.	Continue to provide topic-based training for the NMF platform based on feedback received during previous training sessions.

2.3 Market Roles

TRANSITION held a workshop on the 26th of October 2022 with various industry stakeholders to:

- understand their views on the DSO roles;
- increase their knowledge of flexibility services and associated operations; and
- enable overall engagement in the discussion on DSO roles.

The original remit for the workshop was to consider different market models for how flexibility markets could operate. Market models work is in a state of flux with Ofgem due to report in Q1 2023 on feedback received on its "Call for Input on Future of Local Energy Institutions and Governance" report[12]. It was therefore decided that more value could be obtained by focusing the workshop on the three roles of the DSO as they would be applicable to any future market model.

The workshop was structured to address three main areas:

- A case study was presented to explore how flexibility can support network growth.
- A trading game was run to explore the decisions of participants in different market settings with increasing competition.

[12] Ofgem - Call for Input: Future of local energy institutions and governance, 26th April 2022

- A round table discussion was held to explore how four market roles (interact with the three DSO functions (system planning, market facilitations and real-time operations).

A full report on this workshop is due to published by Dec-22 with the key learnings and recommendations summarised in Section 2.3.1.

2.3.1 Key Learning and Recommendations for TP3

Table 15: Key learnings and recommendations on market roles

Key Learnings	Recommendations
There is a strong appetite for the standardisation of different flexibility market elements, including: products, contracts, timescales, interface, baselining methodology etc.	Consider how to standardise the different flexibility market elements and how this could be implemented in BaU.
Perceived benefits include reduced costs and increased transparency. Some customers prioritise non-financial benefits (e.g. reducing carbon footprint) above competitive market benefits.	Consider differentiating the prices in the marketplace based on risk-reward profiles and the interests of different market participants.
Transparency and data availability are important and closely related to fair pricing.	Consider providing more information to market participants on the local flexibility market to help them make more informed decisions.
Flexibility can have GB-wide benefits and it is important to market participants that flexibility services are fairly rewarded to reflect this.	Explore how flexibility services can be fairly rewarded for the value they deliver, e.g. reducing CO_2 emissions, improving air quality, delivering benefits to other market actors.
Local Authorities, followed closely by DNOs, are seen by most market participants as leading the implementation of the Local Area Energy Planning.	Await further guidance from BEIS before proceeding with future planning work.

2.4 Contractual Documents

There are four legal documents that govern contractual arrangements for TP2; FSA, P2P Term sheet, NMF Ts&Cs, and TCVN. Feedback on these contractual arrangements was collected from market participants via tailored workshops, document reviews, ongoing stakeholder engagement, questionnaires and face-to-face interviews with market participants, and consolidated accordingly. Discussions were also held with new third-party market participants to obtain feedback on the suitability of contracts in relation to risk and reward. The feedback was used to determine the key contractual barriers to market participation.

2.4.1 Feedback on contractual documents

Prior to the commencement of TP2, several changes were made to the contractual arrangements based on feedback at the end of TP1, including:

- simplifying the language and reducing the length of the commercial documentation.
- enabling the viewing and acceptance of the NMF Ts&Cs on the NMF.

- removing the MSPs from the FSA and providing a standalone document for them. There were two market participants who were interested in the MSPs but they were unable to quantify their flexibility and could not progress with the MSPs.
- the use of the TCVN process is better understood by BaU teams and market participants, although it is recognised the timescales (which comply with BaU processes to ensure no applicant is disadvantaged) are too long for the intended purpose.
- assessment of prospective MEC Trade identified a use case for two-way TCVN specifying exact trading period and the traded capacity, where TCVN is applied regardless of the MEC Trade outcome, due to voltage constraint at the network node where both sites are connected.

In addition, the following recommendations from TP1 were considered but not progressed:

- It was not economically justifiable to conduct an independent review of the FSA to simplify it and reduce the time to review by new market participants. However, new third-party market participants provided feedback on the suitability of the FSA. The recommendation from TP1 was passed to the ON-P.

Interviews were conducted with market participants and third-party market participants to obtain feedback on contractual documents. These are still considered to provide a barrier to entry for some market participants that are new to the delivery of DSO-Procured services, due to their strict audit requirements. In particular, the duration of the TCVN process was perceived to be a barrier to entry as it relies on BaU processes and timescales. Two external parties had to sign the FSA in TP2. Both agreed that the length of the contract was appropriate, and that the information contained provided helpful context for the Trials.

2.4.2 Key Learning and Recommendations for TP3

Table 16: Key learnings and recommendations on contractual documents

Key Learnings	Recommendations
The number, complexity and length of the contractual arrangements present a barrier to participating in the auctions for market participants with DERs with lower levels of flexibility or smaller portfolios.	Hold a workshop to consider how the BMR can be used to regulate the marketplace behaviours and enable easier market access, perhaps at a lower risk-reward position.
The work to simplify the language and reduce the length of the contractual documentation was welcomed by those who reviewed the changes.	Further engagement is required to establish whether the changes made addressed the barriers identified in TP1 and what further changes could be made to enable easier market access at a low overall burden.

2.5 Routes to Market for Non-Traditional DERs and Non-Traditional Business Models

A significant increase in the existing level of flexibility will be required to enable the growth of low carbon generation needed to meet Net Zero and to avoid significant infrastructure investment to enable peaks of generation or demand for only a few 100's of hours per year. These non-traditional market participants have several features which are not normally found in BaU flexibility markets:

- organisation type – public or private organisations operating outside of the usual energy industry parties, e.g. energy teams of public sector bodies, community groups, SMEs and domestic premises.
- market knowledge – participants do not fully understand the flexibility markets or have the resources to do so.
- suitable DERs – participants do not fully understand what flexibility is, how to quantify it and how to enable it. One LEO partner commissioned a third party to assist in this activity, primarily because grant funding was available to support the activity.
- technical knowledge – when suitable DERs have been identified, non-traditional providers do not usually understand the level and variability of seasonal flexibility until the opportunity arises.
- flexibility - have DERs with low levels of flexibility (heat pumps, EVs, V2G charges, etc) which may require new methods for forecasting the level of flexibility expected or the level of flexibility delivered or may be interested in deploying energy efficiency measures that can provide long-term energy reduction on the network.
- business models – e.g. organisations that want energy equity, have lower hurdle rates for investment, return the net benefits to the local community and are motivated by the public good.

Section 0 above discussed the work conducted to reduce the contractual barriers for such participants and provided recommendations for further work in this area. Non-traditional market participants are usually small with little knowledge about the market (and the mechanics of how it operates) and have few resources to allocate to consider auction requests.

During TP1 it was suggested an established aggregator may provide a valid alternative route to market that may help address this challenge. Two independent aggregators became market participants during TP2 but it was late in the period and there was limited opportunity for engagement with other market participants. For TP3, the potential for engagement between market participants and external aggregators is to be explored further to determine whether they can be used as an alternative route-to-market. It is unknown if the lack of engagement was due to any reluctance on behalf of the existing market participants, limited opportunity or if this was a deliberate action.

Although overall liquidity increased during TP2 with the addition of two aggregators, there are two main areas that continued to cause concern:

- DER enablement – opportunities from three of the existing market participants were either not viable, delayed or the TCVN process did not support the application. For example, there were technical issues integrating rooftop solar PV with communication modules that created significant delays in expanding the portfolio of controllable DERs.
- lack of DSO-Enabled counterparties – a TCVN needs to be approved before a DSO-Enabled trade can be published on the NMF. Given the few market participants currently available, there is often no viable counterparty for a trade. Furthermore, market participants lack network

knowledge of organisations connected to a particular part of the local network with whom they could trade. Elexon proposal P441 for creation of complex site classes could support bilateral trading of energy within the same substation area and a watching brief is being maintained in relation to this proposal. A good communication strategy is key to identifying and engaging with potential counterparties and this has paid dividends for community engagement for some community-engagement work.

2.5.1 Key Learning and Recommendations for TP3

Table 17: Key learnings and recommendations on routes to market

Key Learnings	Recommendations
There is no standard definition of non-traditional market participants and DERs.	Define non-traditional market participants and non-traditional DERs and look for mechanisms to incentivise energy efficiency.
Non-traditional market participants will often not have the time or resources to understand flexibility services and flexibility markets and may benefit from alternative routes to market.	Review the resources developed to support market participants (particularly LEO deliverable D3.9) and consider the publication of a readily understood user guide for non-traditional market participants. Encourage engagement between aggregators and market participants to determine if this is a viable alternative route to market.
Forecasting the amount of flexibility available from smaller non-traditional DERs can be challenging.	Review the forecasting methods and how they can apply to non-traditional DERs to improve accuracy of availability and reliability of delivery from a portfolio.
Some non-traditional market participants are motivated by the wider social value of providing flexibility, e.g. carbon savings.	Consider how wider social value can support the acceleration of new flexibility and the delivery of the outcomes achieved by DSO-Procured services.
Very few offers were made to day-ahead auctions (see Table 4) which may be more suitable for non-traditional DERs, although it has additional auction resource implications which may not be suitable for non-traditional market participants who often have limited time and resources. .	Market participants with non-traditional DERs should consider this shorter timeframe during TP3 to determine whether this is a viable opportunity.
The outcome of the Strategic Code Review on new connections is expected to increase curtailed connections.	Market participants to consider the consequences of the SCR work.

2.6 Identifying the Social and Behavioural Aspects to Participation

Feedback on the key social and behaviour issues experienced by all market participants was collected at the end of TP2. The analysis was considered in the five key social and behavioural issues identified in the report following TP1.

Table 18: Key Social and Behavioural aspects identified by project participants

Issue	TP2 participant interview analysis
Lack of knowledge about flexibility	**Training sessions** – these have improved since TP1, the provision of training videos has helped considerably and the supportive approach of the SSEN team to help with any issues have all improved the knowledge on flexibility. Knowledge has also increased through

Issue	TP2 participant interview analysis
	involvement in the governance of and participation in the trials. New third-party market participants were involved in flexibility prior to involvement in TP2. **Identifying flexibility** - one organisation employed a consultant to identify the flexibility within their estate, but this was only possible as it was funded by the project. This work represents a financial barrier for market actors who do not traditionally participate in flexibility markets and who need help to understand, quantify and utilise their flexibility.
Lack of skilled resources	**Case studies** - Interviewees were not aware of any case studies which could help them to enable their DERs. These case studies either have not been provided or the participants interviewed were not aware of them. **Bidding in auctions**- the number of auctions in TP2 enabled market participants to trial different pricing strategies, evident from the range of availability price / utilisation price combinations during auctions with and without a price cap (section 2.1). Energy equity can be seen in response to the DCM auction that had no price cap (Table 10). **Review of legal arrangements** – the FSA was reduced in length and simplified. Market participants agreed this was a move in the right direction, but much simpler arrangements were required to encourage greater participation of non-traditional organisations or those with non-traditional DERs. The two third-party aggregators were comfortable with the length of the FSA and the level of detail, suggesting BaU flexibility service providers do not see the FSA as a barrier to entry.
Lack of perceived benefit	**Effort versus reward** – market participants agreed the rewards were substantially less than the costs of participation, however, this is an innovation project, with the corresponding steep learning curve.. Furthermore, familiarity, automation and a commercial market with more market participants would substantially reduce costs and change the economics of participation. **Third party market access** – one organisation considered using a third-party aggregator to manage and control their DERs, including setting the auction strategy. This was not progressed due to resourcing issues and insufficient information to assess the benefits. **Non-financial benefits** – these were often cited by market participants as the main driver for participation in TP2 (as discussed in Section 2.5). This is highlighted by one organisation who took part in a peppercorn MIC / MEC trade to increase internal support for future opportunities in this area.
Customer behaviour affects the viability of trial participation	**Impact of End Users** – there is emerging evidence of (indirect) conflict between building users with open access to HVAC controls who change settings to provide their level of comfort. This is likely to influence the use of HVAC and may change the expected baseline behaviour.
Mixed attitude to risks and innovation	**Brand recognition** – the third-party market participants reported that the positive association with Project LEO is expected to be well-received by shareholders and potential new customers.

2.6.1 Key Learnings and Recommendations for TP3

Table 19: Key learnings and recommendations on social and behavioural impacts

Key Learnings	Recommendations
Improved training, including on-the-job training, has greatly improved understanding of all market participants.	Further information should be gathered on the success of the training materials in TP3, including feedback from third party participants (where possible).
There is a lack of skilled internal resource to manage the different stages of the end-to-end processes as BaU requirements affect availability of personnel. It is	It is proposed this area is further evaluated following TP3 and it is hoped that this will include recommendations for future consideration.

Key Learnings	Recommendations
uncertain if the inclusion of two third-party aggregators will improve matters.	

2.7 Section Conclusions

The increased number of auctions in TP2 allowed the project to further explore the alignment of services and products to different DER types and market participants. As a result, the following conclusions have been drawn on the routes to market:

- Market participants with predictable DERs preferred allocating all capacity to one time horizon as it reduces effort and is more cost effective, and early data from the Trials suggest that the week-ahead auctions are preferable to all DER types.
- The fulfilment of the requested capacity was low across all service types and, in most auctions, this was less than 50%. This is likely due to the strategy used in TP2 where the requested capacity was greater than the total available flexibility from the DERs. Although it was hoped that this would encourage participation and learnings from the Trials, this resulted in an illiquid market and thereby contracts were predominantly priced at or near the maximum TCV.
- The project will need to ensure a higher level of participation in TP3, especially for the DCM and SCM services and MEC / MIC trades for which comparatively little data was collected in TP2.
- The project should ensure all market participants have access to both the Piclo Flex and NMF platforms where possible and that platform training, which received positive feedback during TP2, is continued in the next trial period.
- Barriers to market participation must be further reduced in TP3 to encourage participation in both DSO-Produced and DSO-Enabled services. Feedback suggests the number, complexity and length of the contractual arrangements still presents a barrier to participating as well as non-traditional market actors being unable to quantify and enable their flexibility and determine the benefits.
- Market participants are motivated by non-financial measures, e.g. reducing carbon (section 7.1). As such, the effect and purpose of services like the SEPM service, which is designed to curtail the level of generation during a constraint period, should be considered within the context of alternatives mechanisms, including:
    - increasing the use of ANM;
    - using flexible demand or batteries to maximise the level of generation by effectively changing the demand pattern; or
    - using a profiled (seasonal time of day) import or export capacity to increase demand or reduce generation when there is expected excess generation on the network.

3 Market and Technical Risk for Flexibility Provision

The Market and Technical Risks associated with the delivery of flexibility have been further explored during TP2 by testing new services, delivering over different time horizons, increasing the range of DER types and adding experienced third-party market participants.

3.1 Market Start-Up: Competition, Liquidity, and Reliability Indices

In TP2, we continued to use and develop the market indices used in TP1 to understand the flexibility market maturity at distribution level: these are described in Table 20.

Table 20: Market Indices that measure the maturity of a Local Flexibility Market

Index	Definition	Scoring
Competition	The concentration of a market using relative market share of individual organisations – HHI score (maximum of 10,000).	• Score for an individual organisation is the square of their relative market share. • An HHI of less than 1,500 indicates a competitive marketplace. • An HHI of 1,500 to 2,500 is moderately concentrated. • An HHI of more than 2,500 is highly concentrated. • An HHI of 10,000 is a monopoly.
Liquidity	The supply -demand balance.	• Below one – supply is less than demand. • Equal to one - supply is equal to demand. • Above one – supply is greater than demand.
Reliability	The delivered flexibility as a proportion of the requested capacity and the hours the DER was available as a proportion of the contracted availability hours	• Above 100% - supply was over delivered[13]. • 100% - all supply purchased is delivered. • below 100% - not all supply purchased is delivered and may need to purchase more than demand to ensure a secure market.

In TP2 there has been an increase in both the number of market participants and the volume of capacity offered in auctions across six BSPs. To encourage and test the delivery of DSO-Procured services, no changes were made to the requested capacity during the trials. as there would be no significant learnings by manufacturing changes to liquidity and competition.

3.1.1 Competition Index

The Competition Index determines the market competitiveness and provides indicators for market participants and the DSO. For the market participant, a new market may have a high Competition Index until the number of market participants grows but a lower Competition Index indicates lower barriers to entry. For the DSO, a higher Competition Index indicates less competition and a higher need for a price cap, whilst a lower Competition Index indicates more competition and lower need for a price cap.

[13] The Reliability Index has been further developed to include over supply of flexibility provision as this inclusion offer a better representation of market robustness.

The level of competition in the auctions for SPM and SEPM was analysed and is illustrated in Figure 8 and Figure 9.

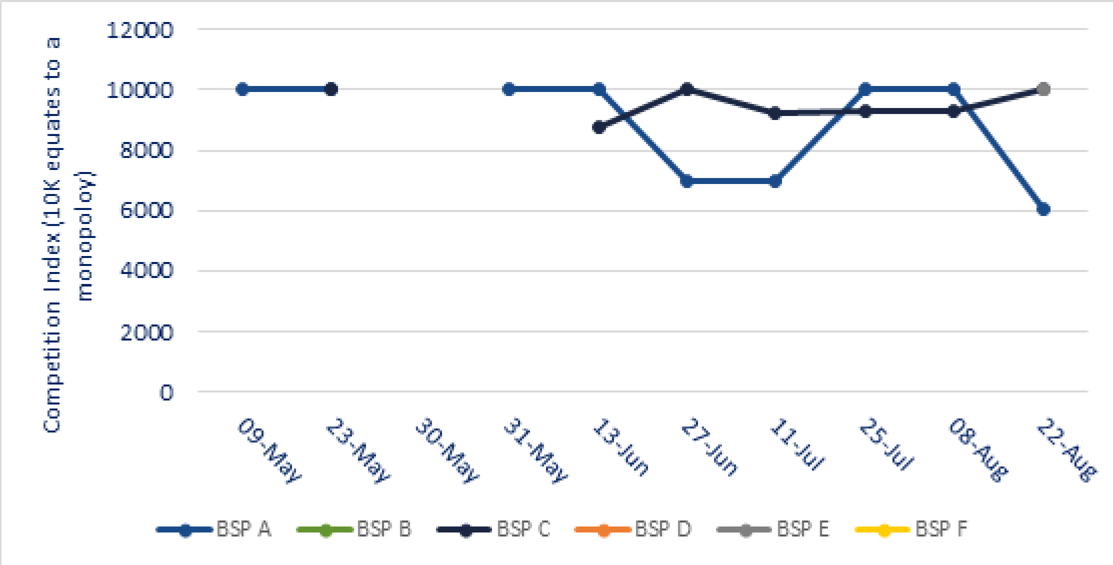


Figure 8: Competition Index for the DSO SPM Market per BSP

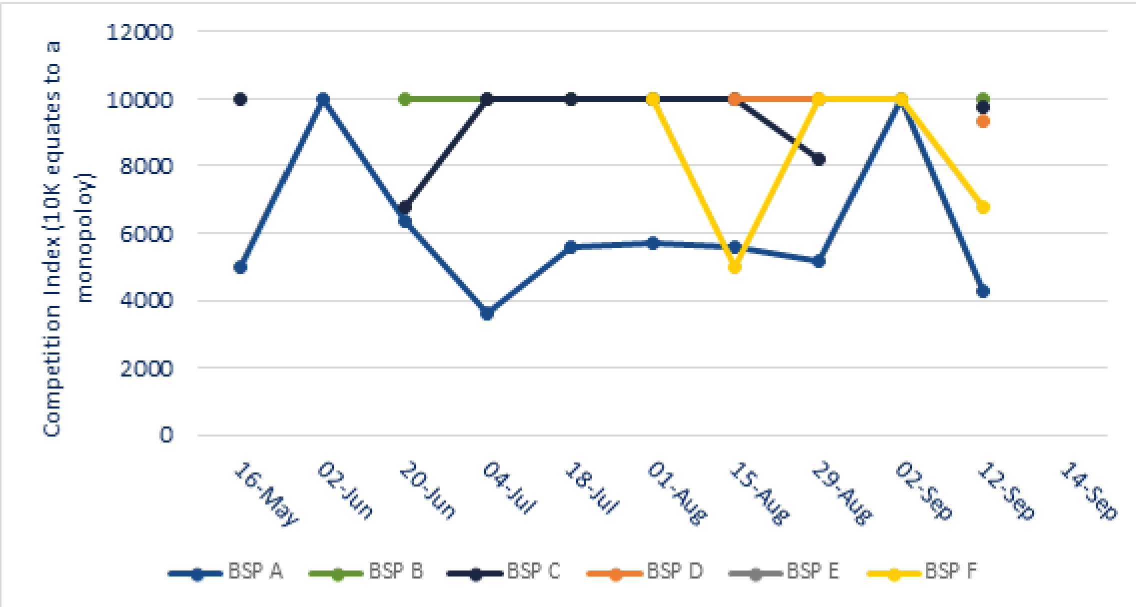


Figure 9: Competition Index for the DSO SEPM Market per BSP

Figure 8 shows that competition in the SPM service at a BSP level remains low (high HHI score) with companies only participating in three BSPs. Competition in the SEPM service is comparatively high (HHI score below 6,000 for most auctions, although there are two auctions where there was only one market participant) due to the additional offered capacity from solar PV which cannot participate in SPM (Figure 9). The higher price ceiling for SEPM also encouraged participation as it included a component for the lost opportunity cost for reduced generation or increased demand.

To assess the impact of ceiling price on competition, Figure 10 and Figure 11 compare the average HHI across all six BSPs, with the average TCV (£/kWh) for SPM and SEPM shown respectively.

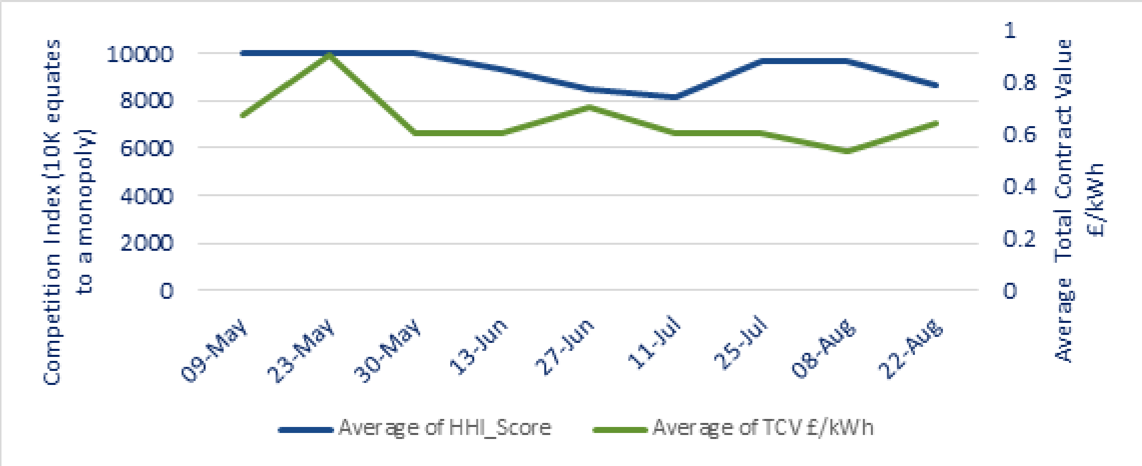


Figure 10: Competition Index for the DSO SPM Market

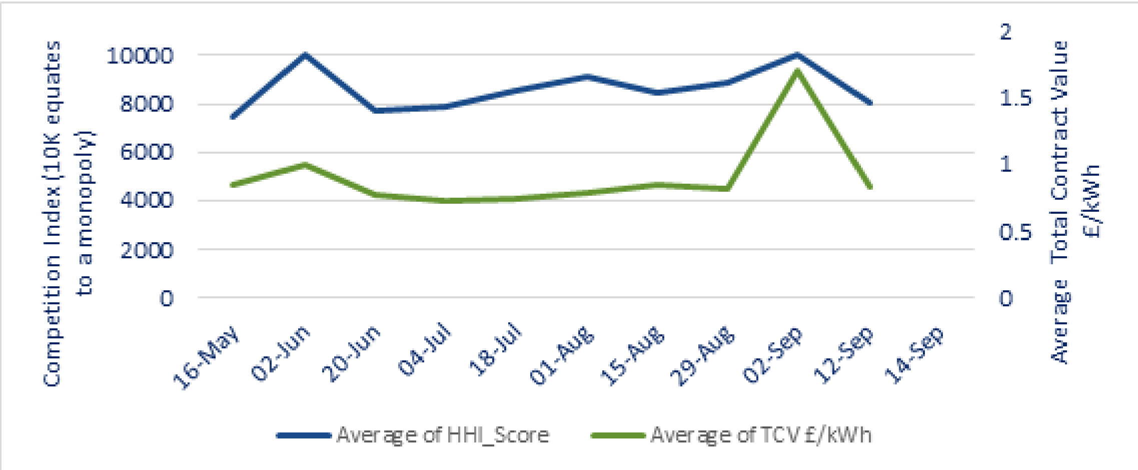


Figure 11: Competition Index and Average TCV across all BSPs for SEPM

Both Figure 10 and Figure 11 indicate low competition with a HHI of more than 7,500. There is no obvious price trend that correlates with the HHI and prices for both SPM and SEPM markets did not deviate from the price ceiling, illustrating the need for a price ceiling when there is low level of competition.

3.1.2 Liquidity Index

The liquidity index indicates the efficiency of the flexibility market behind a BSP, in meeting DSO requirements. In TP2, the liquidity ranged from zero (illiquid) to over one (liquid) as illustrated in Figure 12 and Figure 13.

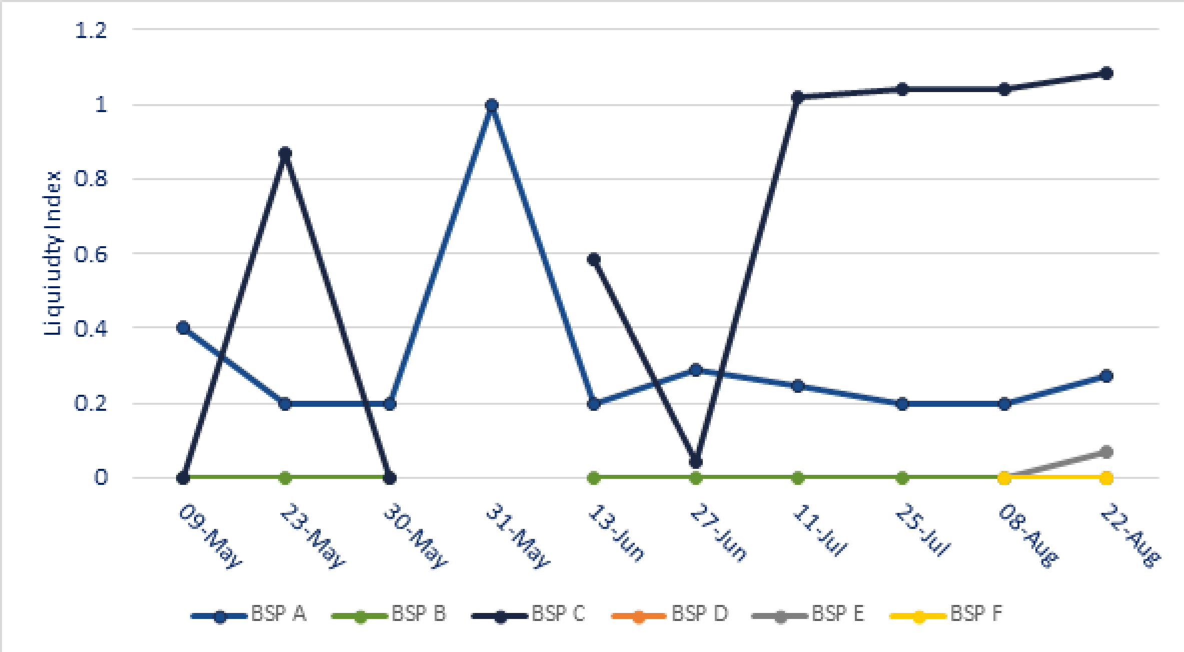


Figure 12: Liquidity Index for DSO SPM per BSP.

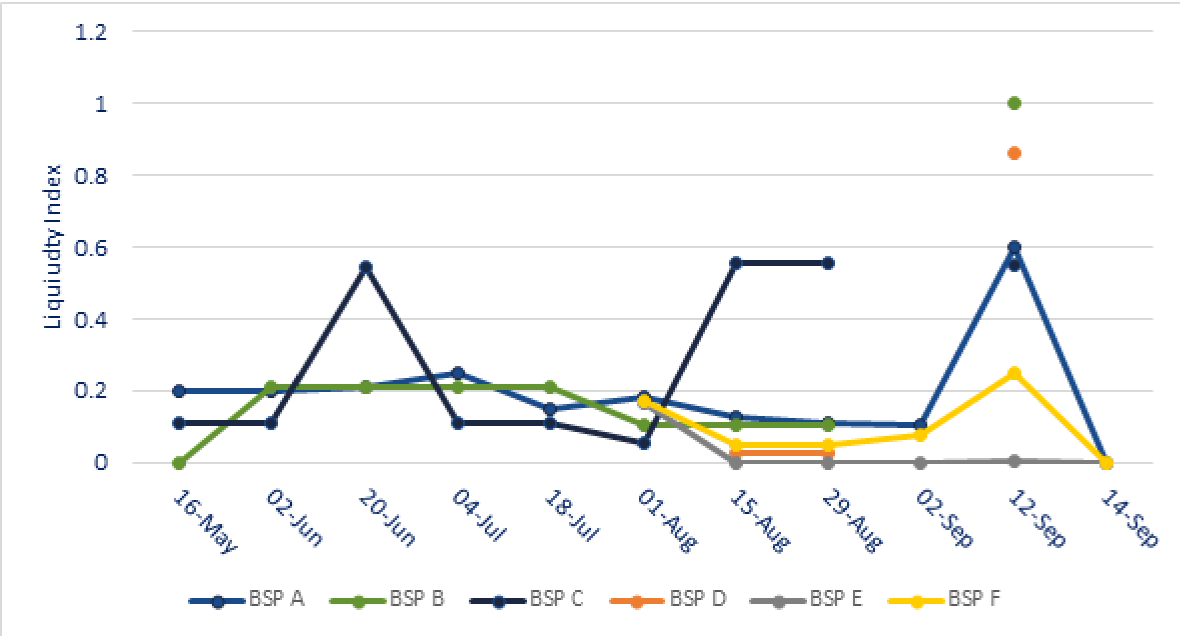


Figure 13: Liquidity Index for DSO SEPM.

As shown above, liquidity in the SPM service remains low, with companies only participating in three BSPs, with only four auctions having a liquidity greater than 1. The liquidity in the SEPM service is higher, partly due to the increase in solar PV which cannot participate in SPM. Figure 14 and Figure 15 compare the average liquidity with the average TCV (£/kWh) for SPM and SEPM respectively.

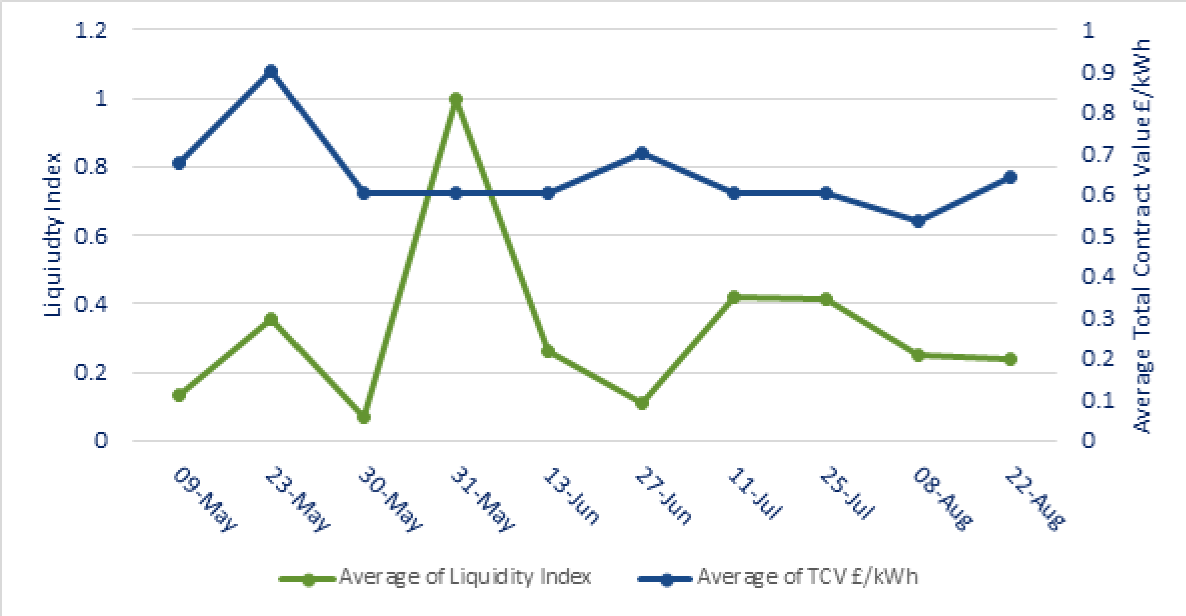


Figure 14: Liquidity Index and Average TCV across all BSPs for SPM

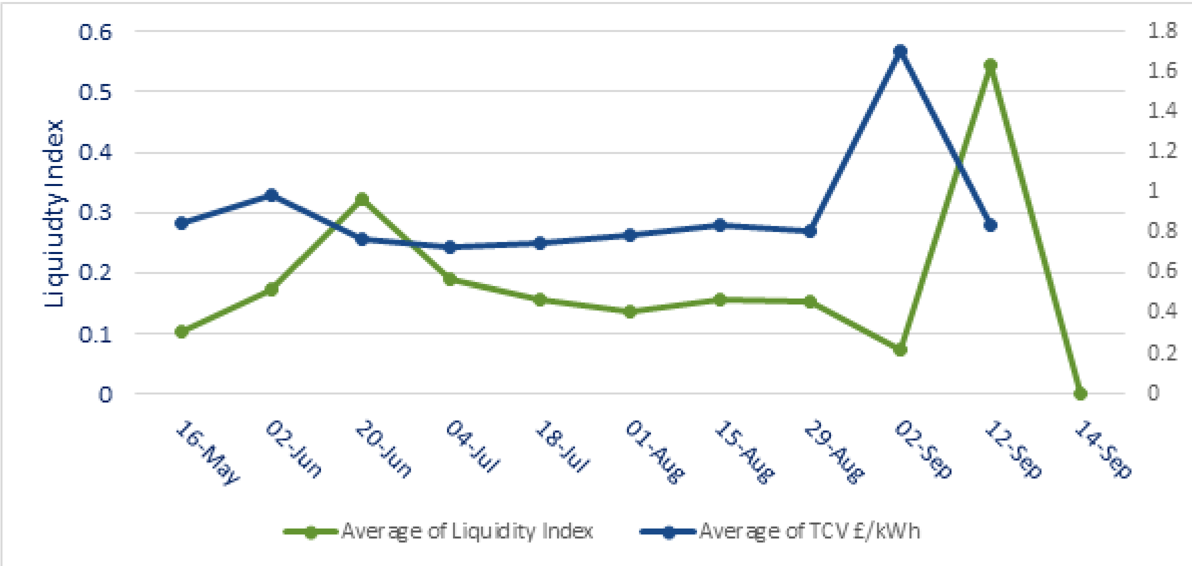


Figure 15: Liquidity Index and Average TCV across all BSPs for SEPM

There is no noticeable correlation between price and liquidity for SPM but a negative correlation between price and liquidity for SEPM due to the increased number of DER types. Prices for both SPM and SEPM markets did not move far from the price ceiling even when it was removed but it is uncertain if this demonstrates a meaningful outcome (although the same outcome happened for SCM and DSM (section 2.1.3 and 0)) when there is low liquidity in the market (this was explored further in sections 2.1.1 and 2.1.2).

3.1.3 Reliability Index

The Reliability Index scores the reliability of each DER type to meet the requested capacity and be available for the contracted service window.

In TP2, the DERs reliability was not capped at 100% and was evolved to include over-delivery. This is due to the behaviour of some participants who may look to over-deliver to meet their contracted utilisation volume and in doing do avoid any under-delivery performance-related payment reductions. Figure 16 shows the Reliability Index (as a percentage) for the five DER types available during TP2 whilst participating in all services with observations provided in Table 21.

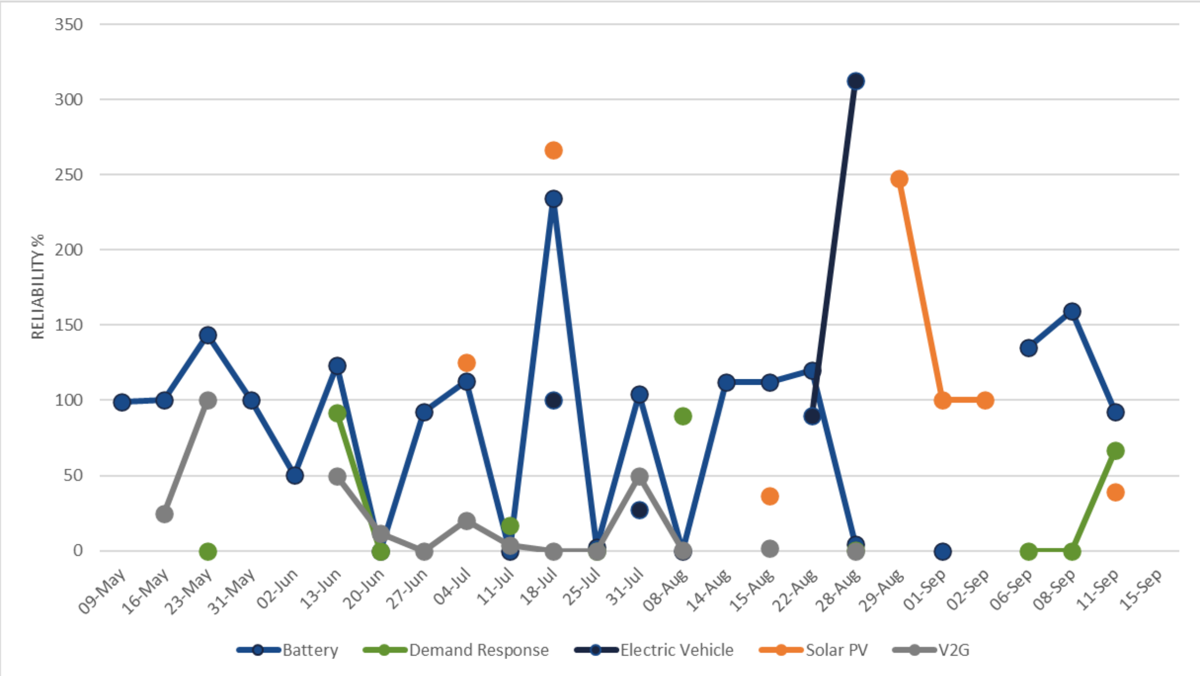


Figure 16: Reliability Percentage by DER type across all services

Table 21: Findings associated from reliability of DERs

DER (Highest Frequency Reliability Range %)	Comment
Solar PV (33%-66%)	Regularly exceeded the requested delivery amount with some outliers. This is caused by cloud cover and the use of historic baselining with same day adjustment (SDA). A more applicable baselining methodology is required.
Battery (99%-132%)	Offers a consistent delivery with the majority at or above 100% with some outliers.
EV (0%-33%) V2G (0%-33%)	There are few data points for the EVs due to their delayed introduction the Trials. EVs and V2Gs require the driver to connect the vehicle to the charger and there are two inherent differences between the DERs: • notification to the users - EVs were generally depleted and started charging once plugged in at home (service delivery location) but could be interrupted for service delivery. V2Gs were not necessarily plugged in at the office (service delivery location) but at home. Further V2Gs were also generally depleted but could not provide services until they had a minimum charge level which increased uncertainty and service delivery.

DER (Highest Frequency Reliability Range %)	Comment
	• Baselining - if a V2G historically discharged in accordance with a time of use tariff (ToUT) and this overlaps with an event, baselining will show lower delivery as there is no change to the normal pattern of behaviour.
DSR (0%-33%)	There are very few data points for DSR. However, the data collected shows low reliability due to the novelty of using these DERs and is expected to increase with experience and automation.

3.1.4 Key Learning and Recommendations for TP3

Table 22: Key learnings and recommendations on market start-up: competition, liquidity, and reliability indices

Key Learnings	Recommendations
Increasing competition and liquidity in flexibility markets can reduce prices but the illiquid nature of the auctions meant the price cap usually prevailed.	Consider reducing the requested capacity to near or below the available capacity of the participating DERs to increase liquidity and increase the opportunity for learning from competitive bidding.
Early data indicates the reliability varies by DER type with battery and solar PV having higher reliability than EVs, V2G and DSR	During TP3, investigate how the reliability model can be improved to consider more of the variables affecting delivery; this may consider derating to improve delivery certainty.
Current baseline methodology for some DERs introduces errors into the reliability indices.	Investigate alternative and more appropriate baseline methodologies that can reduce errors in the measured delivery for DERs.

3.2 Market Start Up: Flexibility Delivery and Unavailability

3.2.1 DSO Procured Services

DNOs can use flexibility to resolve constraints and defer or avoid reinforcement until there is a more certain future. This optionality can reduce overall capital expenditure and reduce costs to consumers. This section considers the risks of using flexibility to maintain security of supply (under-delivery and unavailability). These risks are mitigated through over-procurement (reduce the risk of failure of a DNO asset) or over-provisioning (reduce the risk of contractual penalties).

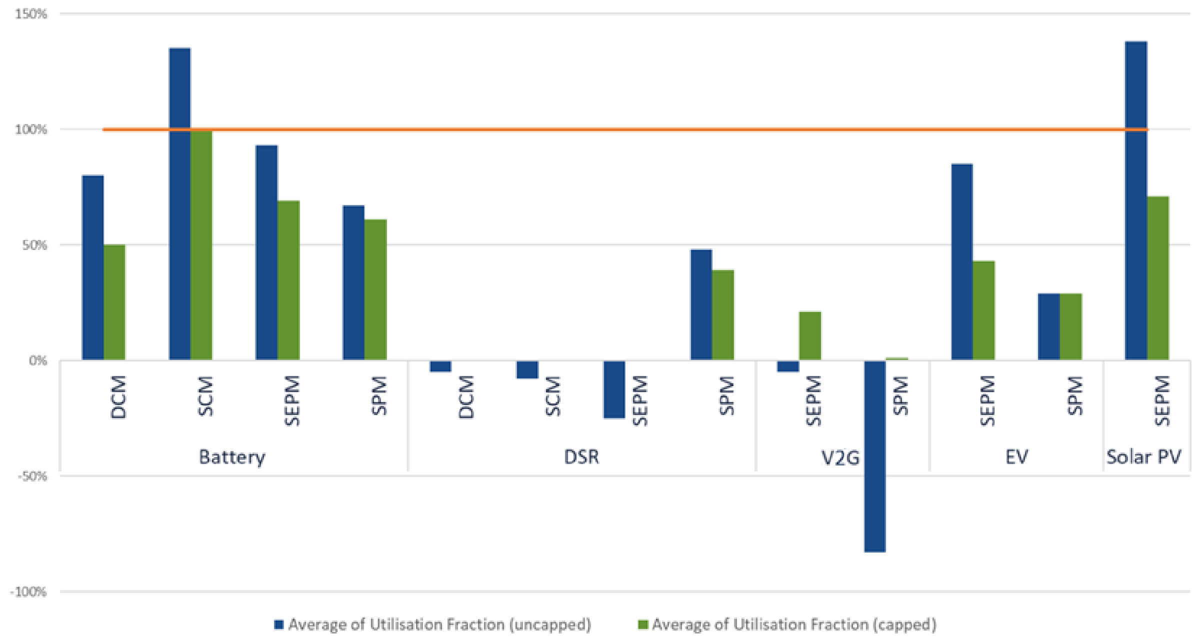


Figure 17: Risk of Delivery (Average Utilisation Fraction)

Figure 17 shows the ability of the different DER types to provide DSO-Procured services during TP2 using the average Utilisation Fraction Metric, a measure of the capacity delivered as a proportion of the requested delivery:

- The battery and solar PV installations have the lowest risk of under-delivery, with both providing an average Utilisation Fraction of at least 50% across the services in which they delivered; the battery participated in all DSO-Enabled services, whereas solar PV installations only performed in SEPM.
- The battery performed particularly well in the SCM service (Average of Utilisation Fraction of 100% (capped)), whilst comparatively underperforming on the DCM (Average of Utilisation Fraction of 50% (capped)). This is reportedly due to the relatively short notice period for the DCM service which meant that the battery could not be fully charged ahead of time. This is an operational issue that can be addressed with charging windows provided between service delivery periods.
- Demand Side Response participated across all service types with limited success. From Figure 17, the SPM service is the most suitable to this DER type; however, as the DER participated in a comparatively high number of events for this service[14], the results may be somewhat skewed.
- The EV and V2G portfolios achieved better results in SEPM than SPM. The SEPM service is a response to excess generation on the network and has a longer delivery window outside of tea-time peak (00:00 – 04:00 and 10:00 – 14:00). This service may therefore be favourable to these DER types as driver behavioural patterns may be more predictable at these times (i.e. less driver activity over night and during the working day). It is noted however that the EV chargers

[14] DSR participated in 9 SPM events compared to 6 SEPM events.

(which provide flexibility via smart charging) performed better than the V2G portfolio (which can provide energy back to the grid).

The FSA allows market participants to declare a DER unavailable for planned and unplanned issues that affect the level of delivery. Unavailability presents a risk to both the DNO (risk to DNO assets if a constraint cannot be mitigated) and the market participant (reduced payment under the FSA). Further, the risk of DER being unavailable informs the procurement strategies for DSO-Procured services and reduces the level of offered capacity that can be delivered. A valid DSO strategy is to over-procure to mitigate the risk to DNO assets. There is a similar and valid strategy for market participants to over-deliver to avoid reduced payment under the FSA.

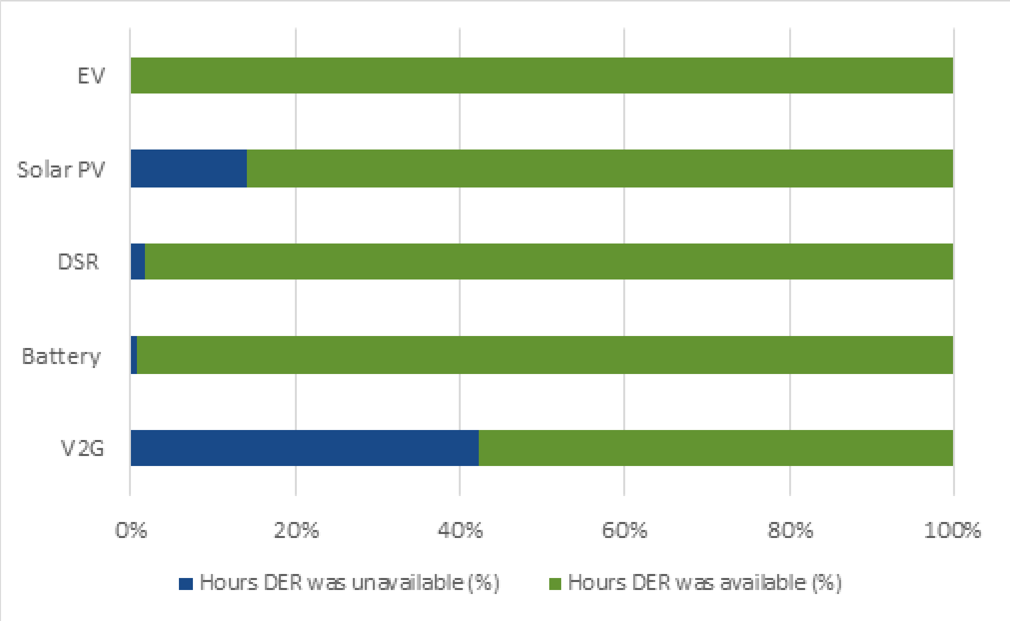


Figure 18: Risk of Unavailability per DER type

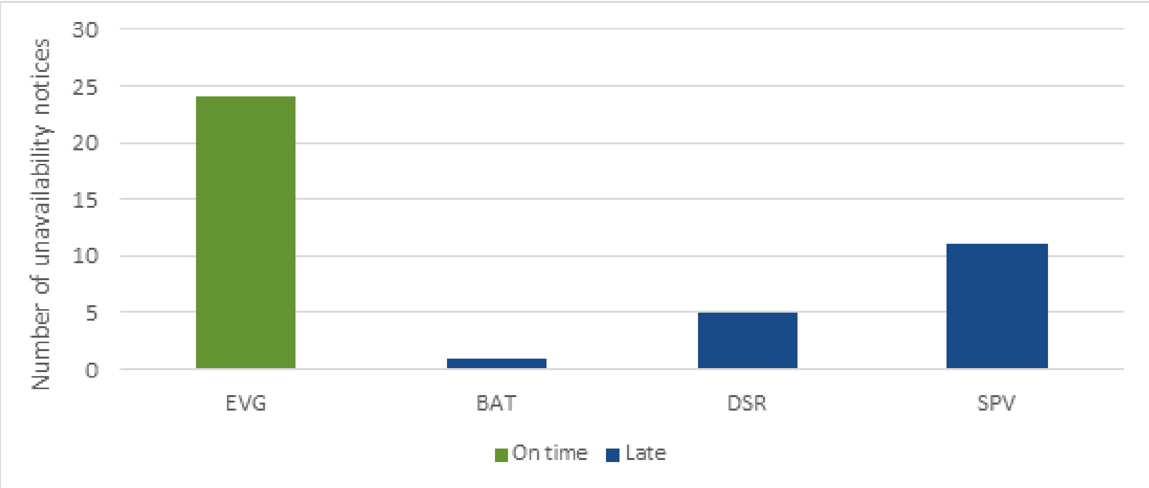


Figure 19: Unavailability notices by DER type

As shown in Figure 18 and Figure 19, the proportion of hours a DER was unavailable and the number of availability dispatch notices submitted varied between the DER types. The V2G and solar PV DERs had significantly higher unavailability than the other technologies. This is somewhat expected; the level of flexibility provided by these technologies is intrinsically linked to external factors, e.g. user behaviour and weather. This means the risk that one of these DERs will be unavailable is typically higher, although it is noted that this was not the case for the EV chargers which did not submit any unavailability notices in TP2 and, to a lesser extent, the DSR DER, which is dependent on both user behaviour and weather.

Feedback on the challenges faced by the LEO partners when delivering flexibility was collected during face-to-face interviews after the end of TP2 and highlighted further perceived risks to participation, including:

- Lack of real-time data and forecasting solutions to accurately quantify the available flexibility of some DERs, particularly DSR, EV, V2G and solar PV.
- Lack of time, resources and knowledge to participate in a growing number of auctions for DSO-Procured services, especially those participating with an aggregated portfolio of DERs; and
- Risks of ensuring the DSR and solar PV have the appropriate control and monitoring equipment to meet the DSO-Procured service requirements.

3.2.2 DSO-Enabled Services

DSO-Enabled services share many of the risks of DSO-Procured services, but the buyer and the seller can overload the network in an unmanaged way if they exceed the revised MEC levels.

There have been insufficient trades of DSO-Enabled services to make a viable market (9 across both TP1 and TP2 with no successful delivery). There are three issues:

- Market participants lack network information to identify potential counterparties.
- The DNO has little understanding of their customers, no commercial relationship and no resources to identify potential counterparties and obtain approval to share details.
- The TCVN process ensures there will be a safe network for the revised MEC or MIC. However, the approval process is aligned to BaU for fairness and too long (65 business days). This limits market liquidity and the viability of DSO-Enabled services for use in BaU.

3.2.3 Key Learning and Recommendations for TP3

Table 23: Key learnings and recommendations on market start-up: flexibility delivery and unavailability

Key Learnings	Recommendations
Season-ahead auctions for SPM and SEPM were considered too risky and day-ahead auctions required too much effort.[15].	Auction risks need to be further tested in TP3 across all three time horizons.
The timing of DSO-Procured services can make a service attractive to EVs and V2G portfolio, e.g. if EVs and V2Gs are not plugged in at the service delivery time they cannot participate.	The impact of scaling up the number of chargers in a portfolio should be investigated in TP3 to determine if this affects the risk of under-delivery.

[15] DCM and SDM were day ahead only during TP2

Key Learnings	Recommendations
Some DERs had a high risk of non-delivery compared to others, e.g. battery and solar PV versus DSR and V2G.	Determine if there are underlying reasons for this, if alternative forecasting solutions would help and if the risk reduces with experience.
Unavailability is likely to affect the attractiveness of some DERs and DSO procurement strategies.	Conduct further testing and analysis to understand unavailability across a range of DER types, auction timescales and DSO-Procured services.
There have been too few DSO-Enabled services to support meaningful analysis.	Test DSO-Enabled services with more trades and an increased number of participating market participants (or find an alternative means to address the issue).
An API was developed to streamline the communication between the satellite and central markets such that requests can be automatically sent out from the central markets and automatically returned from the satellite market.	Review the use of APIs during TP3 to determine where these are required to lessen the burden on market participants.

3.3 Technical Start Up: Market Platform Development, Automation, Monitoring

This section concentrates on advertising the need, delivering the flexibility and baselining. It discusses the following:

- Market platform development, employing an agile iterative approach building on the ability to run auctions, collect meter data, verify delivered capacity and conduct settlement (4.3.1).
- DER control and automation including individual DER and aggregated portfolio to participate in the required DSO-Procured service (4.3.2).
- DER delivery including the submission of metering data for baselining and verification of flexibility delivery (4.3.3).
- Network monitoring from local LV network and the wider HV network (4.3.4).

3.3.1 Agile Market Platform Development

The agile approach adopted during TP2 has resulted in the successful implementation of one additional API to allow the NMF to communicate auction responses to Piclo Flex. The updated status of the platforms by the end of TP2 is summarised in Table 24.

Table 24: Functionality of Market Platforms

Functionality	NMF	Piclo Flex
DER Registration	Throughout TP2	Throughout TP2
Advertise auction for DSO-Procured service (peak management)	Throughout TP2	Throughout TP2
Advertise auction for DSO-Enabled service (trading of export and import capacity)	Throughout TP2	N/A
Receive auction offers	Throughout TP2	Throughout TP2

Functionality	NMF	Piclo Flex
Notify market participants of contract outcomes	Throughout TP2	Throughout TP2
Notification of changes to availability of DERs	Future work	Future work
Schedule and instruct DERs	Throughout TP2	Before TP3

3.3.2 DER Control and Automation

A wider range of DER types participated in TP2 (see Table 1: Summary of Changes in TP2 compared to TP1).

Table 25: Flexibility Service Parameters

Area	During TP2	During TP1
DSO-Procured Services	Sustain Peak Management (SPM), Sustain Export Peak Management (SEPM), Dynamic Constraint Management (DSM) and Secure Constraint Management (SCM)	SPM
DSO-Enabled Services	Maximum Export Capacity (MEC) and Maximum Import Capacity (MIC)	MEC and MIC (offline)
Geographical Coverage	6 Bulk Supply Points (BSPs) - Bicester North, Cowley Local, Oxford, Drayton, Headington and Witney-Yarnton	3 BSPs - Bicester North, Cowley Local and Oxford
Participating DER Types	Batteries, Electric Vehicles (EV) which use smart charging, EV to Grid (V2G), solar PV, hydro and Demand Side Response (DSR)	Battery and (V2G), hydro and solar PV
Products (procurement timeline)	Season, Week and Day Ahead	Week Ahead
Service windows	DSO-Procured: 0000 - 2400 DSO-Enabled: 0000 - 2400	DSO-Procured: 1500-1900 DSO-Enabled: 0000 - 2400
Scheduled/Forecast	Scheduled	Scheduled
Service Days	Mon – Sun	Mon – Sun
Total Auctions	DSO-Procured:116 DSO-Enabled: 8	DSO-Procured: 41 DSO-Enabled: 7
Total Events	DSO-Procured:93 DSO-Enabled: 2 (no physical delivery)	DSO-Procured: 69 DSO-Enabled: 4 (no physical delivery)

The joint approach to trials identified six flexibility services to be delivered that either support the network (DSO-Procured) or improve the efficient use of existing capacity (DSO-Enabled). A description is provided below, Table 2, with a full description of each service provided on the LEO website.

The trial plan also detailed the planned auctions and delivery events for DSO-Procured service and DSO-Enabled service, using a variety of contracts and how buyers and sellers would interact with the market (Neutral Market Facilitator (NMF), Piclo, or offline) with increased complexity as the trials progressed.

Market participants control their DERs in many ways, from individual DERs, e.g. standalone battery or generation unit, to groups of DER of the same type, to groups of DERs that behave in the same way, e.g. same load profile or temperature effect. The DSO determines how best to model these DERs in the PSA module to provide a balance between visibility, complexity and speed of modelling.

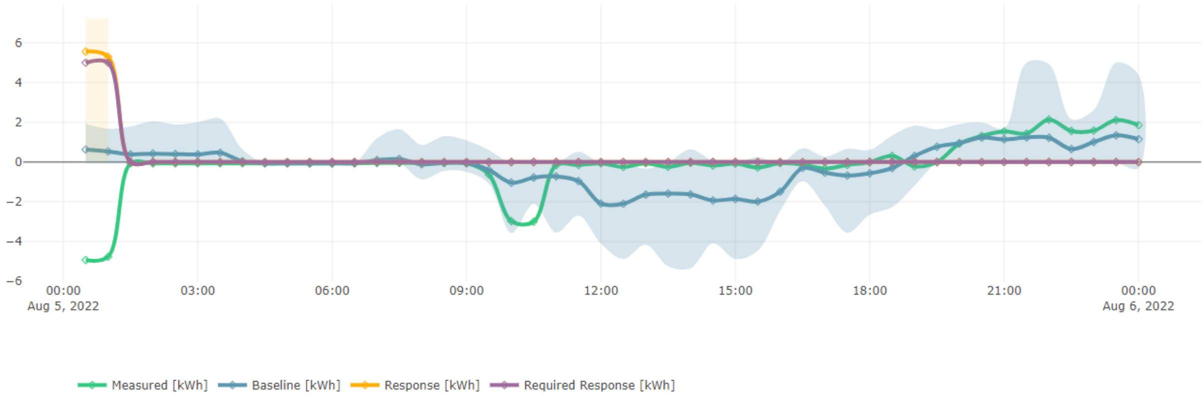
The level of automation used to implement a utilisation instruction varies between market participants, with approaches ranging from the sophisticated (manual DSO instructions with automatic scheduling and dispatch that uses an algorithm to allocate the instructed capacity across individual DER or DER groups and automated data collection) to semi-automated (manual DSO instructions and scheduling of individual or groups of DERs with semi-automated dispatch and data collection).

3.3.3 DER Delivery

As with TP1, the levels of delivered capacity for DSO-Procured services were measured using one of the two baseline methodologies[16]:

- Historic Baseline was used for the majority of flexibility events during TP2 and compares the metered data provided by a market participant with a historic baseline created from metered data provided by the market participant for eight weekdays and two weekend days over the previous eight week with a same day adjustment (SDA) to account for any demand pattern variation during the event day.
- Nomination Baseline was used for one EV event during TP2 and compares the metered data provided by a market participant with the forecast baseline data submitted by the market participants before 1700 the day prior to the event day.

An extended list of DSO-Procured services were trialled during TP2, including SEPM, SCM and DCM. Figure 20 illustrates the delivery from one participating asset (i.e. a community battery) using the historic baseline with SDA for an SEPM event.



[16] SSEN Transition: Baselining for the trials /

Figure 20: Illustrative delivery of an SEPM event from community battery

- The required response (purple line) is 10kW (5kWh) in each Settlement Period (SP).
- Delivery is successful if the metered data for an SP is 4.75kWh (95%) or more (shaded yellow).
- The historic baseline after SDA (blue line) is 0.628kWh in SP1 and 0.533kWh in SP2.
- The measured data for the event day (green line) is negative indicating the battery is charging (as required).
- The delivered response is the difference between the historic baseline with SDA and the metered data on the event day (yellow line); 5.565kWh (SP1), 5.303kWh (SP2) and 0kWh at all other times.
- The battery was successful in delivering this SEPM event in full.

The SDA considers the level of measured data in the 2h prior to the start of the event. A battery providing the SEPM service would be charging during the event. If the battery was discharging during the 2h window prior to the period (which could be following its use in another service) it will create a higher baseline which could result in an over-delivery if the market participant had not declared the charging.

The baselining methodology can affect the level of delivery as can be seen in *Figure 21* and *Figure 22*.

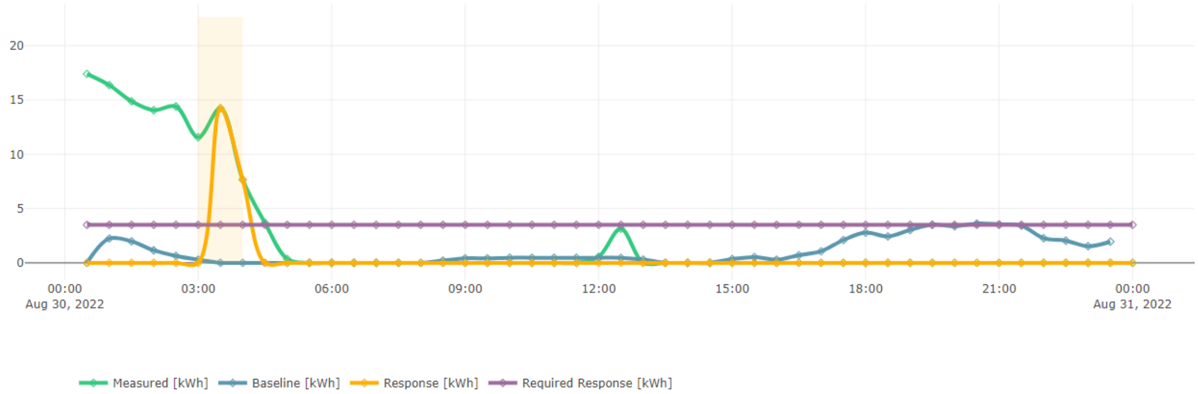


Figure 21: Illustrative delivery using nominated baseline for an EV portfolio

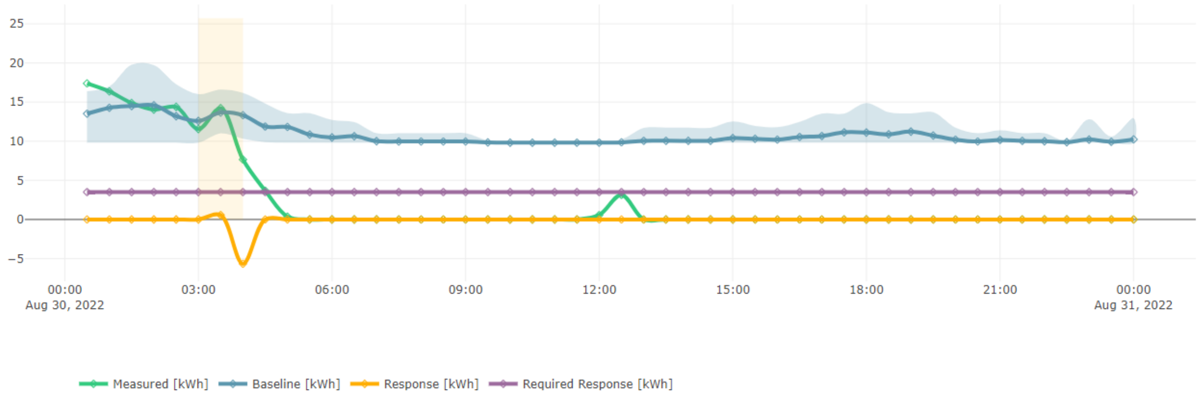


Figure 22: Illustrative delivery using middle 8 of 10 with SDA baseline for an EV portfolio

The responses using nominated baseline (Figure 21) are 14.229kWh and 7.661kWh, reflecting a fully successful delivery for the required 7kW flexibility. With historical baseline methodology for the same event, Figure 22 shows the responses as 0.567kWh and -5.667kWh, i.e. no delivery.

Two main observations regarding the verification of DER delivery are:

- Historical baseline methodology without SDA is less effective for the weather dependent DERs, including solar PV, hydro and DSR.
- DER providers perceive it to be onerous to create a nomination baseline. Whilst this can be true for some DERs, e.g. those affected by external factors that are difficult to predict, for other DERs, e.g. batteries, this can be relatively easy as the DER changes state to deliver a service.

3.3.4 Network Monitoring

The effect of delivered capacity for DSO-Procured services on the LV network was monitored at the local secondary substation using a low-cost substation monitor (Eneida Deepgrid One). The data collected enables the DNO to determine the effect on local network performance and provides data for areas of the network not previously monitored at LV to identify and verify real-time network issues and faults. One hundred units have been installed in Oxfordshire to date (Figure 1).

Figure 23 illustrates the effect of 16kW delivered capacity from a community-based battery during SPM events from 1800-1900 hours on 12 Jul 2022 and 15 Jul 2022 (highlighted). The delivery was separately verified using DER metering data and using historical baseline with SDA.

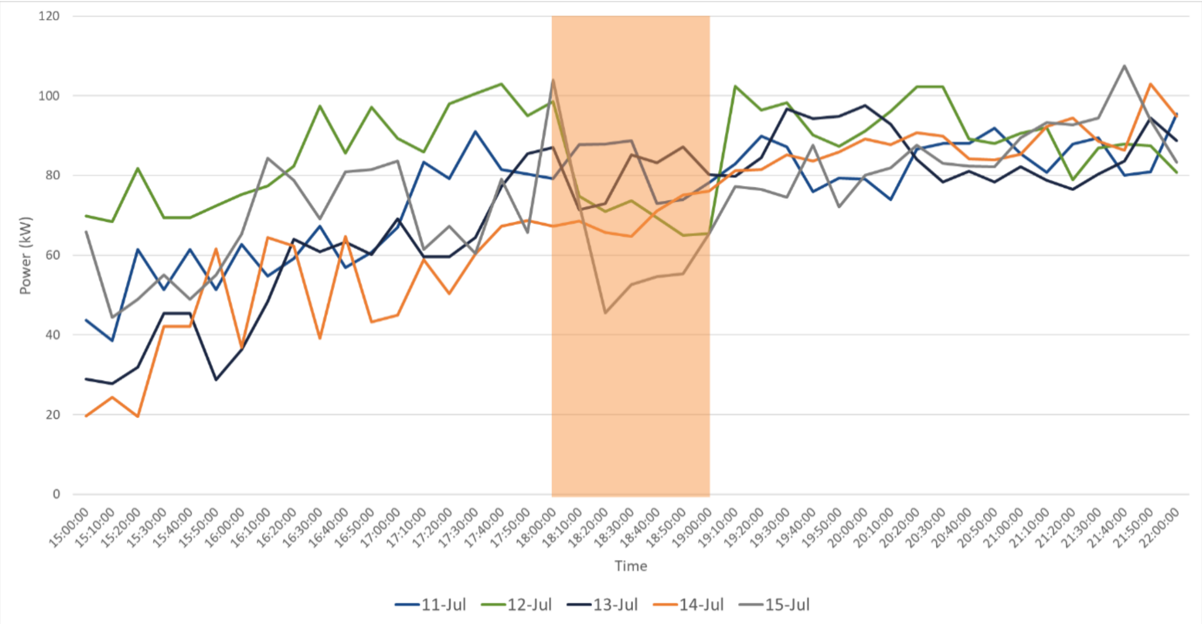


Figure 23: Effect of service delivery on LV feeder (power)

It is hard to quantitatively analyse the effect on the substation from the 16kW flexibility delivery due to the relatively small level of flexibility compared to the rating of the substation and the suitability of the analysis methods. However, qualitatively there is a visible demand reduction for 12 Jul and 15 Jul compared to other weekdays due to the battery discharges during the event. The main observations regarding network monitoring are:

- The offered capacity can be relatively small compared to the feeder capacity and may not be detected by substation monitors if the underlying demand and generation pattern is volatile.
- LV monitoring provides visibility of changes as a result of delivered capacity but there is insufficient experience to reliably determine the effect of services on the LV network.

3.3.5 Key Learning and Recommendations for TP3

Table 26: Key learnings and recommendations on technical start-up

Key Learnings	Recommendations
When using metered data to verify delivery of DERs, the use of historic data with SDA may produce misleading results and market participants are reluctant to use nomination baseline.	Consider alternative forecasting solutions, continue to develop a regression baseline methodology and encourage market participants to provide nomination baselines for evaluation during TP3.
The provision of data for verification purposes and the issuance of the settlement report is slow, cumbersome, and costly.	Consider how the end-to-end process can be more automated to reduce costs of participation in DSO-Procured services.
There are additional technical challenges to be overcome in relation to the ongoing development of the NMF and Piclo platforms.	Platform development to ensure consistent data exists across platforms; SCM and DCM to be phased in via an API and provide further price visibility.

3.4 Section Conclusions

Following the recommendations from TP1, the price cap was increased across all services with the aim of increasing market competition, liquidity, and reliability. TP2 has seen an increase in the number of market participants and the level of capacity offered in auctions across six BSPs, with the following conclusions being drawn on the market and technical risks for Flexibility Provision:

- Competition for the SPM service was low in comparison to the new SEPM service. This is likely due to the additional offered capacity from solar PV which cannot participate in SPM, and the higher price ceiling for SEPM.
- Liquidity remained low for the SPM service and was relatively higher for SEPM. There was no noticeable correlation between price and liquidity for either the SPM service, but a low correlation between price and liquidity for SEPM due to the increased number of DER types.
- The battery and solar PV DERs offered the highest average reliability for SPM and SEPM during TP2, with Demand Response, Electric Vehicle and V2G DERs less likely to be available once contracted. This is consistent with the findings from TP1 and is somewhat expected; the level of flexibility provided by these technologies is intrinsically linked to external factors that are difficult to accurately predict, e.g., user behaviour and weather.

- The Utilisation Fraction Metric, a measure of the capacity delivered as a proportion of the requested delivery, showed that, like their ability to be available for contracting the service, the battery and solar PV DERs also have the lowest risk of under-delivery when delivering that service.
- Market participants have reported difficulties in quantifying their flexibility and providing a nominated baseline, furthermore the historical baseline methodology is shown to be less effective for the weather dependent DERs (including DSR) and EVs. This means it is difficult for the market participants to forecast their flexibility and thereby perform against the metrics provided in this report.
- Different DERs seemed to perform better in some services than others, for instance the SEPM service appears to be favourable to EV portfolios. However, there is still limited data surrounding the SCM and DCM services for comparisons to be drawn. Further, there is lack of data for the different auction timescales.
- There was a lack of trading partners to enable MIC / MEC trades in TP2. DSO-Enabled services will have similar risks to the DSO-Procured Services which must be explored.

4 Unintended Consequences

The efficient operation of a Smart Local Energy Market requires fair and equitable access for all, with standards of behaviour for market participants during the auction and delivery phases to minimise the scope for unintended consequences and / or gaming.[17] The contractual arrangements and the BMR developed during TP1 were developed further during TP2:

- A BMR workshop refreshed understanding, introduced updates, reinforced required behaviours, and introduced a new self-reporting mechanism to identify issues with the BMR. The only issues identified were in relation to the functional operation of the auctions which were addressed through NMF development.
- Improved platform functionality and auction reporting addressed identified opportunities for gaming, including cancellation of long-term contracts for advantage from short-term contracts.
- Commenced the discussion regarding how best to hold reserve capacity and adequately reward flexibility. If unmanaged, the DSO over-procures to protect DNO assets and the market participant over-delivers to avoid contractual penalties. At best, this could sterilise valuable capacity at LV and at worst it could discourage new flexibility due to reduced payments and increase costs to the customer.

[17] Where “unintended consequences and / or gaming” are defined as “deliberate behaviour designed to give an unfair advantage to one or more parties or to manipulate the market to benefit one or more parties”.

- Baselining methodologies were reviewed to increase their applicability to DERs that do not have a regular pattern of use or require pre-conditioning (e.g., batteries and EVs) and reduce the potential to game the baseline.
- Commenced the discussion on the application of the BMR to flexibility markets and whether there should be a separate contractual arrangement for larger and smaller market participants, including non-traditional market participants.

4.1 Key Learnings and Recommendations for TP3

In general, the combination of the market rules, contractual arrangements and the operation of the Market Platform mean many gaming opportunities have been engineered out.

Table 27: Key learnings and recommendations on unintended consequences

Key Learnings	Recommendations
It is difficult to determine if DER pre-conditioning prior to Service Delivery is preparing for service delivery or gaming.	Explore whether alternative methods of baselining would be better suited to DERs that require pre-conditioning and / or better capture gaming.
There were very few submissions via the BMR self-reporting mechanism, suggesting the BMRs were not actively used by market participants during TP2.	Hold a workshop during TP3 to discuss the wider application of BMRs and the appropriate contractual arrangements for larger and smaller market participants, including non-traditional market participants.
There needs to be agreement on how best to hold reserve capacity at lower voltage levels where there is less flexibility available.	Continue discussions on who should hold reserve and the wider issues at lower voltages.

4.2 Section Conclusions

A new self-reporting mechanism was introduced to allow market participants to identify and notify of any issues with the application of the BMR during TP2. Unfortunately, very few issues were identified and all related to the functional operation of the auctions which were addressed through NMF development. This implies market participants have not actively used the BMRs during TP2. Discussions have commenced in relation to important topics:

- Market governance - the use of the wider application of BMR and the appropriate contractual arrangements for larger and smaller market participants, including non-traditional market participants.
- Optimising flexibility use - how best to hold reserve capacity and adequately reward flexibility, particularly at lower voltage levels.

5 Commercial – DSO

The DSO is tasked with ensuring a safe, secure and reliable network, accommodating electricity flows required for the energy transition in a cost-effective way. This includes consideration of flexibility as an alternate to infrastructure until there is a more certain future. The ceiling price for flexibility is based on the cost benefit analysis for network reinforcement with an optionality premium for the benefit of deferral until there is a more certain future. Below the ceiling price, flexibility has a positive NPV for a period and above the ceiling price, network reinforcement is a better solution.

5.1 DSO-Procured Services Benefit

During TP2 SPM and SEPM DSO-Procured services were tested across six BSPs. Each BSP was each assessed for reinforcement costs as if there was a transformer capacity issue, e.g. a 20 MVA transformer currently loaded at 14.7 MVA would have its rating artificially reduced to 15MVA. As the simulated load grows over time, the level of flexibility required to return the asset a safe operating state varies. The cost of cable replacement on the 33kV network was included.

The 2022 ENA Common Evaluation Methodology (CEM) Tool for Network Investment Decisions[18] was used to assess the Net Present Value (NPV) of deferring large CAPEX expenditure associated with network reinforcement. This was compared to procuring DSO-Procured services using the availability and utilisation prices from the TP2 trials for SPM. The other services were not considered when using the ENA CEM tool as it assumes that reinforcement is needed for peak demand and not peak generation or for an outage scenario. Utilisation was assumed to be two hours a week, and availability based on a four-hour service window (15:00 -19:00) every workday. The average availability and utilisation prices bid into the auctions and used in the CEM tool for the six BSPs are shown in Table 28.

Table 28: Average Flexibility Prices from the SPM auctions run at the six BSPs in TP2

BSP	Availability Price £/MW/h	Utilisation Price £/MWh
BSP A	7.7	544.1
BSP B	0.0	0.0
BSP C	41.6	449.7
BSP D	0.0	0.0
BSP E	0.0	600.0
BSP F	0.0	0.0

The CEM tool can also be used to determine the optimal duration of DSO-Procured services if used to defer reinforcement. This can be achieved using a Least Worst Regret and Weighted Average basis across all four Distribution Future Energy Scenarios (DFES) scenarios published in March 2022[19]: Leading the Way, Consumer Transformation, System Transformation and Steady Progression. Using the most optimistic DFES scenario of demand (Leading the Way[20]), the value calculated can be used to determine a price ceiling that the DNO would pay until there is more certainty on the peak demand.

[18] Flexibility services, ENA website
[19] Distribution Future Energy Scenarios 2021 (ssen.co.uk)
[20] In the Leading the Way scenario, consumers are engaged and active in improving energy efficiency with a mix of solutions.

Cost Benefit Analysis

BSPs A, C, E were chosen for analysis as there were SPM prices which involved the four DFES scenarios and included carbon reductions from deferred reinforcement. The outcome is shown in Figure , Figure 24 and Figure 25 and numerically in Table 29, Table 30 and Table 31; the NPV and provides the optimal deferral years and maximum flexibility value across the scenarios. The tool additionally analysed maximum benefit from weighted average optionality analysis (assuming 20% chance of each DFES scenario) and the intrinsic benefit based on the Least Worst Regret analysis. The difference between the maximum benefit and the intrinsic benefit provides the uncertainty value.

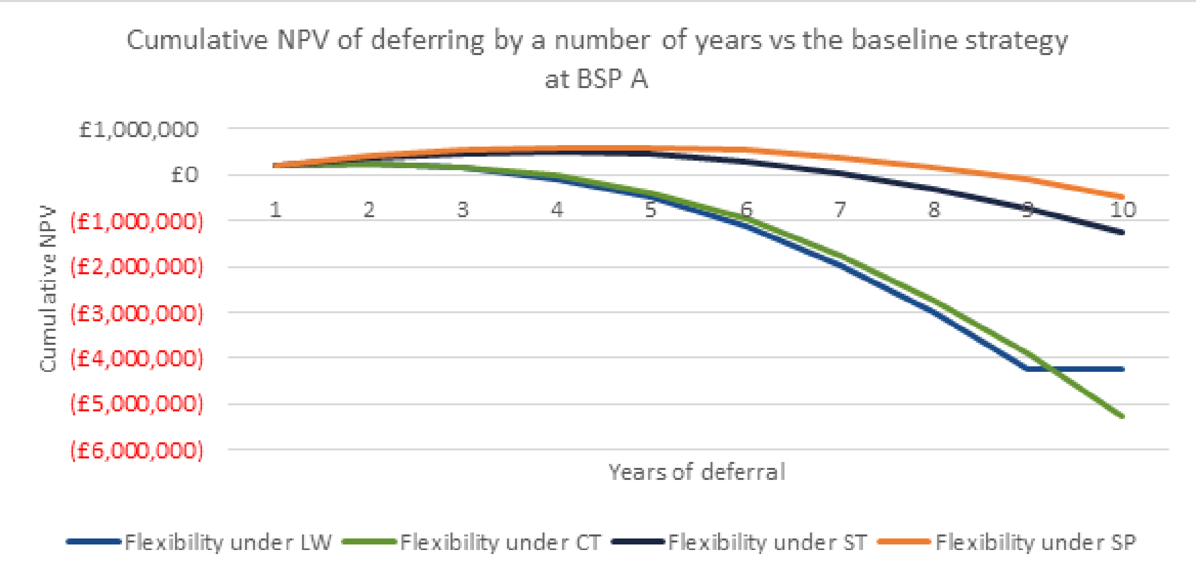


Figure 27: Cumulative NPV for flexibility against reinforcement deferment at BSP A

Table 29: Optimal reinforcement deferral duration by NPV and scenario at BSP A

DFES Scenario	Year of Maximum Cumulative NPV at BSP A	Value of Maximum Cumulative NPV at BSP A
Leading the Way	2	£246,504
Consumer Transformation	2	£256,818
System Transformation	4	£497,009
Steady Progression	5	£604,574

The outcome of the weighted average analysis (across all 4 scenarios) is that BSP A would benefit from flexibility for up to two years (maximum Cumulative NPV) as it is cheaper than investment in network assets. At year two the DNO can conduct further analysis to determine whether to continue to use flexibility or to invest in growing the network capacity.

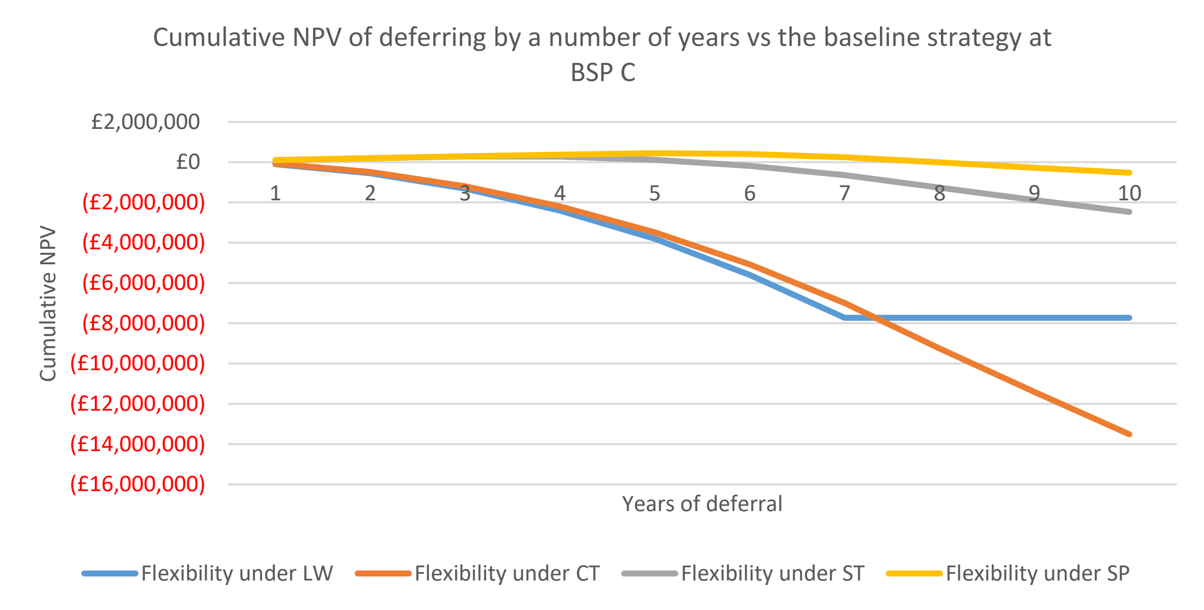


Figure 24: Cumulative NPV for flexibility against reinforcement deferment at BSP C

Table 30: Optimal reinforcement deferral duration by NPV and scenario at BSP C

DFES Scenario	Year of Maximum Cumulative NPV at BSP C21	Value of Maximum Cumulative NPV at BSP C
Leading the Way	0	£0
Consumer Transformation	0	£0
System Transformation	3	£286,518
Steady Progression	5	£446,834

The outcome of the weighted average (across all 4 scenarios) analysis is that BSP C would benefit from flexibility for up to one year (maximum Cumulative NPV) as it is cheaper than investment in network assets. At year one the DNO can conduct further analysis to determine whether to continue to use flexibility or to invest in growing the network capacity.

21 When the Year of Maximum Cumulative NPV is zero occurs when reinforcement is required from the outset and there is no role for flexibility.

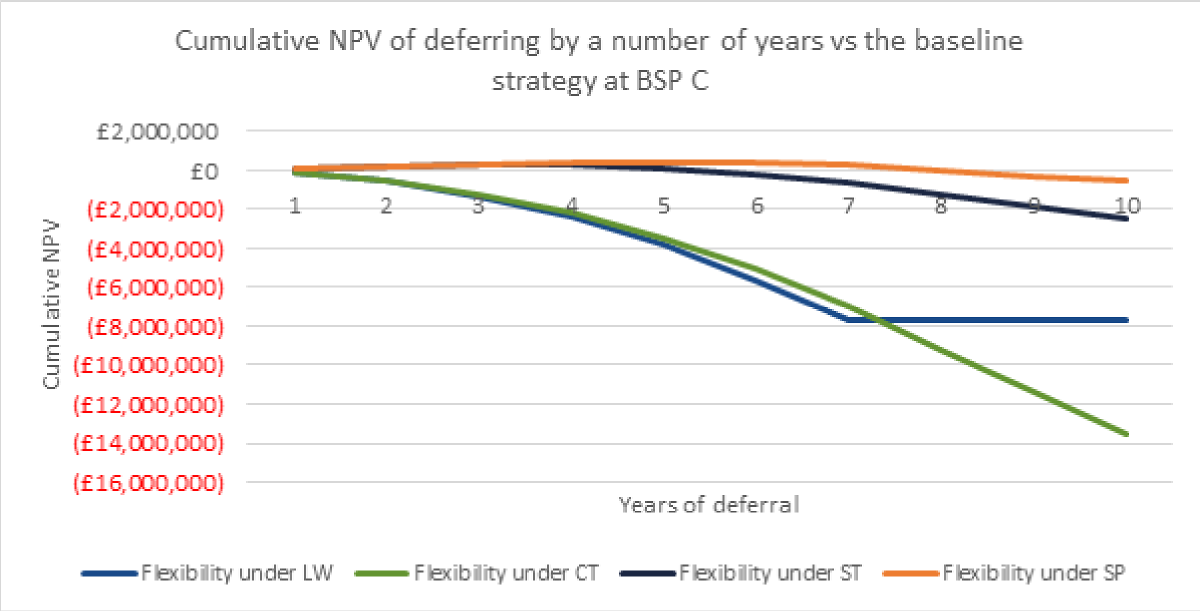


Figure 25: Cumulative NPV for flexibility against reinforcement deferment at BSP E

Table 31: Optimal reinforcement deferral duration by NPV and scenario at BSP E

DFES Scenario	Year of Maximum Cumulative NPV at BSP E	Value of Maximum Cumulative NPV at BSP E
Leading the Way	1	£153,874
Consumer Transformation	1	£153,702
System Transformation	1	£163,873
Steady Progression	2	£195,506

The outcome of the weighted average (across all 4 scenarios) analysis is summarised in Table 32. BSP E would benefit from flexibility for up to one year (maximum Cumulative NPV) as it is cheaper than investment in network assets. At year one the DNO can conduct a further analysis to determine whether to continue to use flexibility or to invest in growing the network capacity.

Table 32: Optional Flexibility value across three BSPs

BSP	Optimal years of deferral	Maximum Expected Benefit by strategy	Intrinsic benefit based on Leading the Way	Uncertainty benefit	Price ceiling based on Intrinsic benefit £/MW/h
BSP A	2 years	£320,981	£246,504	£74,477	900
BSP C	1 year	£112,554	£-	£112,554	0
BSP E	1 year	£133,391	£153,874	-£20,483	150

Across the three BSPs the benefit of implementing SPM varies significantly. At BSP A the optimum contract length is two years and offers the maximum expected benefit by strategy. Under these conditions, with an intrinsic benefit of around £250,000, this analysis supports the use of flexibility for two years at BSP A over investing in network replacement. BSP A is also the area with the most liquidity and lowest flexibility prices (see Section 4.1). This highlights the need for more mature markets where the competition, liquidity, and reliability indices are mature in a DSO-Procured flexibility market for it to offer a benefit to the DSO and, ultimately, connected customers.

BSP C and E have only an optimal of one year of flexibility instead of reinforcement. Based on this analysis, further consideration would be required of the benefits to both market participants and the DSO of a one-year flexibility contract versus the ability to reinforce immediately.

5.2 Key Learning and Recommendations for TP3

The auctions held during TP2 at the six BSPs have allowed the testing of the DSO-Procured service market at a new price ceiling with updated demand scenarios for three of the BSPs. This allows the DSO to determine if the price for SPM offers a cost-effective solution against traditional CAPEX solution. The following learnings and recommendations were found.

Table 33: Key Learnings and Recommendations on the Flexibility Services Benefit analysis

Key Learnings	Recommendations
The CEM provides a value for substation reinforcement and the included carbon reductions from deferred reinforcement.	A higher level of liquidity is required for a CBA to draw meaningful results, although this could be achieved by determining the breakeven price and comparing to market prices.
It is unclear what is and is not included in the CEM and whether it is an appropriate model to adequately value flexibility.	Consider shortcomings of the CEM, how they can be overcome or addressed and whether they would make a meaningful difference for DSO-Enabled services.
A detailed understanding is needed of the Flexibility requirements to understand the benefit to the DSO	Applying probabilities to each demand scenario and using these to calculate the weighted average NPV will identify the optimal length of a contract. Using this contract length and the least worst regret intrinsic value to calculate the price ceiling reduced the risk to the DSO of a demand varying from the prediction.

5.3 Section Conclusions

The 2022 ENA CEM Tool for Network Investment Decisions was used to determine the NPV of using flexibility to defer large CAPEX expenditure and identify the optimal period to use flexibility to defer reinforcement. Only three of the six BSPs had non-zero prices and the results show:

- It is uncertain what is and is not included in the CEM Tool.
- Across the three BSPs, the benefit of implementing flexibility varies significantly and depends on the market liquidity and prices.
- The analysis supports the use of flexibility over investing in network replacement for two years at BSP A and one year at BSP C and BSP E. BSP A has the most liquidity and lowest flexibility prices which highlights the need for more liquidity.
- There is additional option value for flexibility, due to the inability to physically deliver the level of reinforcement required in the time available, which will increase the amount of flexibility required beyond the bounds of the CEM model.

- Investing in enabling flexibility at the grid edge, also has additional option value as a route to enabling participation in agile tariffs, and ESO markets, meaning there is less need for larger plant such as batteries to be built on the Transmission System.

6 Commercial – DER – Introduction

There is a wide variety of market participants and DER types taking part in TP2. Each DER type will have different operating characteristics and thereby be suited to different services; just as each market participant will have different business models and require different incentives for participating in TP2.

There were more market participants and DERs types delivering a wider range of services and products (see Section 1). However, there is still a lack of commercial data being collected and shared as part of the Trials. The concept of a "Holistic Business Model" was progressed in TP2, with the assessment having been expanded following the trial of more DERs for this participant and the delivery of the additional services procured and enabled during the trial period.

6.1 Comparing and Contrasting Different DER Types

Market participants continue to have commercial sensitivities regarding the sharing of their bespoke financial models and the corresponding inputs and outputs. The information in this section has therefore been summarised from those LEO partners who participated in TP2. The outputs will be used to determine; (i) the economics of delivering DSO-Procured services from different DERs and (ii) the practicalities and benefits of delivering DSO-Procured services using a variety of DERs and DSO-Enabled services using a variety of sites.

6.1.1 Comparison of Costs for DER Type

The main cost for a market participant is the enablement of a DER to provide a DSO-Procured service. These costs fall into two categories: central costs (communication and despatch platform, billing and settlement systems, and data exchange APIs) and local costs (communication, control, and metering). Making DERs flex-ready is relatively easy and cheap for new DERs where the capability can be designed and included from the outset. Retrofitting a flex-ready capability is more complex and can vary from relatively cheap, e.g., the addition of a cheap control / metering module, to very expensive e.g., specialist control equipment to make the output of a DER variable (replacement inverters for rooftop solar PV or variable drives for a run of river hydro). The cost of additional changes to an existing DER can be relatively significant and it would not be cost-effective outside of an innovation project, e.g., the experience of one market participant with a large solar PV installation is that retrofitting flexibility to the installation would have cost 12 times as much as designing this in from the outset. For DERs participating in TP2 and the delivery of DSO-Procured services, the additional revenue stream is marginal and may be less than the income from services for DERs with low level of flexibility. Feedback from the partners indicated that the non-financial benefits may be more meaningful to an organisation e.g., carbon savings or delivering a community benefit.

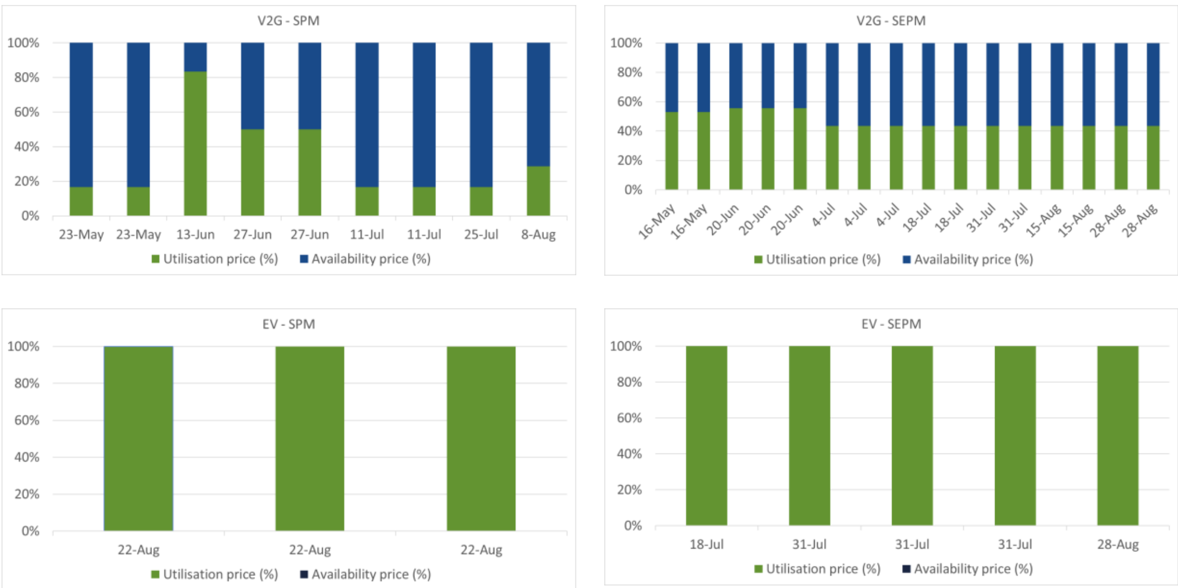
6.1.2 Comparison of Baselining for DER Types

The two baselining approaches being used during TP2 were discussed in section 3.3.3 [22]. A baselining working group explored different methodologies for baselining in the context of market services and identified the following issues and anomalies related to baselining for different DER types[23]:

- The choice of error metric can be important when comparing different baselining methodologies and account for the relative level of flexibility to the background load. For example, using the average demand during the event interval to calculate relative or percentage errors makes the error metric for DERs with near zero baseline (domestic customer or battery with local monitoring) appear artificially high due to dividing by a number close to zero.
- The application of SDA can negatively affect baseline accuracy if an (irregular) event-related action occurs in the SDA window. This is particularly relevant for EVs, V2Gs and batteries which may need to charge prior to service delivery.

6.1.3 Utilisation and Availability Payments

DSO-Procured services are contracted through an auction process with the price comprising an Availability Price and a Utilisation Price[24]. Figure 26 illustrates the share of Availability Prices and Utilisation Prices for different DER types during TP2 auctions.



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[22] Baselining for the trials | SSEN Transition (ssen-transition.com)
[23] Baselining Working Group – Summary Report, unpublished
[24] Payment | SSEN Transition (ssen-transition.com)

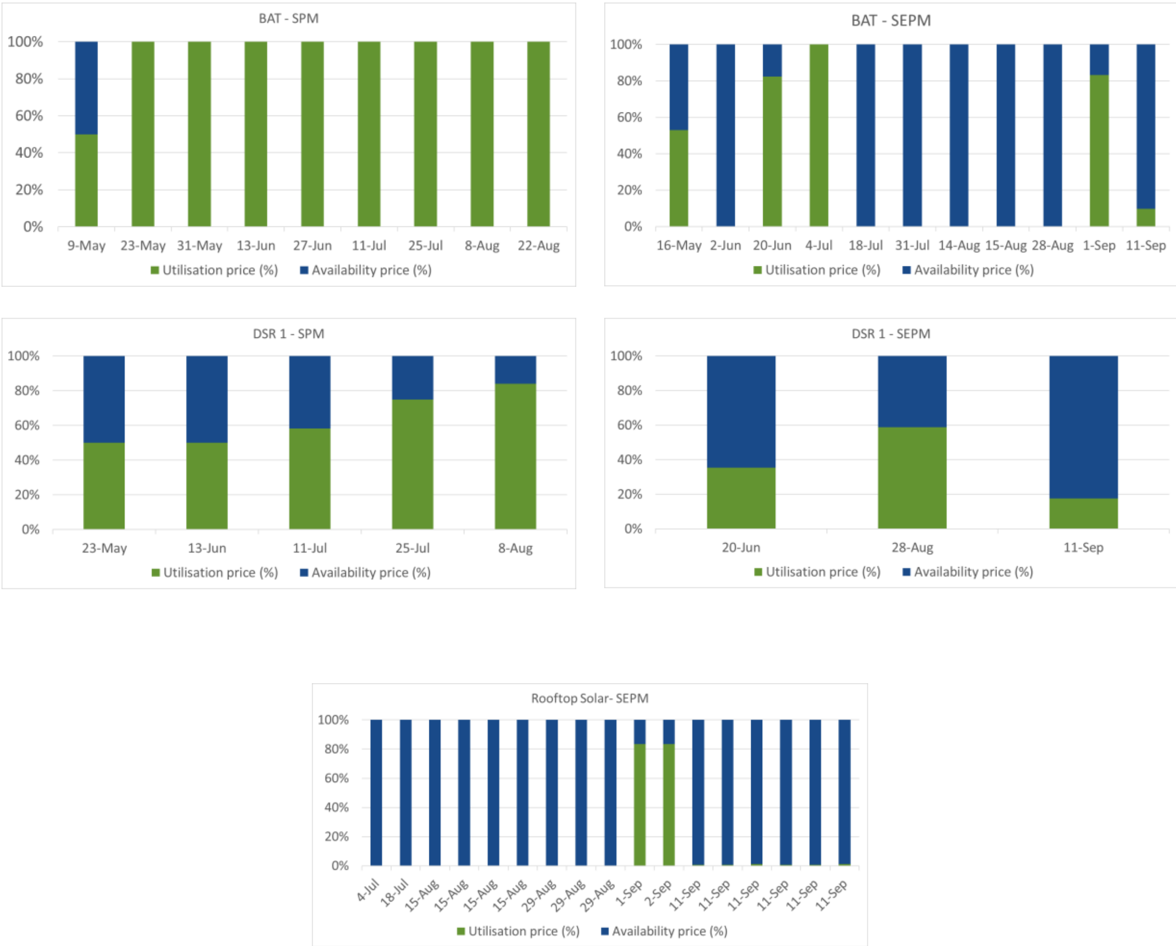

Figure 26: TP2 auction prices shown as %-age split between availability and utilisation at auction by DER type

Figure 26 illustrates how strategies differed depending on the service[25], DER type and market participant:

- The V2G chargers tended to favour a higher Availability Price for both SPM and SEPM services, although the approach was more balanced for SEPM. In both services, the share of the Availability Price was increased above the Utilisation Price as the pricing strategy matured towards the end of TP2. This strategy is similar to that adopted by this participant during TP1 and may indicate a lower risk approach is preferential for this DER type.
- The EVs opted for an alternative approach, relying solely on the Utilisation Price when providing SPM and SEPM.
- The battery was able to support the different pricing strategies (including all Utilisation Price or all Availability Price) due to the higher certainty of delivery.
- Qualitive feedback for the DRS 1 indicated a higher share was attributed to the Availability Price when the weather looked to be uncertain. This can be seen in the above graphs which show

[25] Please note that the price paid for the DCM service is solely based on the Utilisation Price

an increase in the share of the Utilisation Price above that of the Availability Price during the months when the weather pattern was more stable and warmer (Jul-22 and Aug-22).

- The portfolio of rooftop solar tended to rely solely on the Availability Price when providing SEPM.

6.1.4 Market Liquidity and Perceived Value of Services

The analysis of market value and the perceived value of DSO-Procured services is discussed in sections 2.1 and 4.1

6.1.5 Key Learnings and Recommendations for TP3

Table 34: Key learnings and recommendations on comparing and contrasting DER Types

Key Learnings	Recommendations
Commercial confidentiality prevented any meaningful qualitative analysis. However, the commercial benefits are much less than the costs of participating in TP2.	Engage with market participants through a series of workshops to elicit the financial data that can be provided and conduct analysis.
New DERs that are flex-ready can often provide DSO-Procured services at a cost-effective level.	Consider how this can be encouraged, particularly for SFNs and community projects.
The current baselining methodologies are not appropriate for all DER types which will put some at a disadvantage in terms of their financial reward.	Continue to determine the most suitable baselining methods for different DER types to inform TP3 and beyond.
The non-financial benefits are more important than the financial benefits to market participants during TP2.	Encourage market participants to open up about the non—financial benefits to ensure they are captured so the market can be informed of non-financial motivations.
The availability / utilisation price split differed depending on the service[26], DER type and market participant.	Engage with market participants more to understand their motivations for the pricing.

6.2 Comparing and contrasting holistic business models

There are a range of business models used by different market actors, including DSO, DNO, community schemes, funders, platform providers and private equity. These were explored in general terms during TP1 through one market participant who operated with a non-standard business model (community energy scheme with DER investment). This exploration continued during TP2 and was expanded to include the additional DERs used by the same market participant to deliver a wider range of DSO-Procured services. Other business models will be considered after TP3 when more data and experience is obtained.

[26] Please note that the price paid for the DCM service is based solely on the Utilisation Price

6.2.1 What do we mean by holistic business models?

TP1 considered the value proposition canvas that explored other value creation opportunities, such as reducing carbon or energy costs to an organisation, individual or community. These did not consider higher-level business models such as "technical aggregator" or "local convenor"[27].

A review of existing literature was conducted during TP2 to consider what is meant by "holistic business models" and how to characterise the different types or 'levels' of business model. The resulting interpretation is that a holistic business model considers a coordinated approach to the market / customers and is about adding value on top of a core business model.

A key objective of TRANSITION it is to evaluate holistic business models to provide a route-to-market for market participants, and for LEO it is to demonstrate and evaluate business models for smart local energy systems. Within the remit of TP2, a holistic business model was considered as any business model that uses flexibility inherent in normal operational activities to:

- deliver one or more DSO-Procured services where the purpose of the service is always defined by the DNO;
- deliver one or more DSO-Enabled services where the purpose is to enable other users connected to the local network to benefit from spare network capacity; or
- deliver benefit as part of a model for a smart local energy system, e.g. a model based on the Community of MPANs concept[28].

The above definition should be considered further during TP3.

6.2.2 Different levels of holistic business model

When considering the range of market participants in TP2, there were a range of different types of business models and considerations which are captured in Table 35. Some of the examples provided could be implemented for DERs developed solely to profit from DSO-Procured services.

Table 35: Different levels of holistic business model

Business model	Examples	Relevant considerations
Single-DER operational model	• Rooftop solar PV: ○ behind the meter (BTM) benefits ○ BTM and SEPM • Ground mount solar PV: ○ SEPM ○ Offsetting / MEC trading	• Do flexibility services provide a route to market for DERs? And, if so, how? • What level of additive benefit(s) do flexibility services provide specific DER-service combinations and at what points is it financially viable? • Can income from flexibility services support or accelerate the deployment of renewable generation projects by increasing the financial viability of prospective generation projects?

[27] "Low Carbon Hub Portfolio Routes to Market (D3.7)", Low Carbon Hub and Origami Energy, December 2021.
[28] "Community of MPANS (D3.8)", Barbara Hammond and David Middleton, September 2021.

Business model	Examples	Relevant considerations
Portfolio operational model	• Smart community energy scheme with wholly-owned DERs (combination of generation, demand and storage with BTM optimisation and community-wide optimisation to provide DSO-Procured services and DSO-Enabled services).	• As above with the addition of services to third party DER owners and / or other smart community energy schemes • Is it make or buy a DER control platform for portfolio flexibility operations alone and what is the breakeven point?
High-level business model	• Technical and / or commercial aggregation service for DERs • DER technical control platform provider • Local convenor (could encompass different services both B2B and B2C e.g. customer acquisition service, community engagement, facilitation of smart scheme creation, provision of community-scale DERs) • Flexibility trading optimisation platform for services and wholesale trading	• Assessment of the viability and value creation of any high-level business model, drawing upon a combination of the more specific operational models, such as those identified above, along with any enabling hardware, systems or skills investment.

6.2.3 Do Flexibility Services increase the viability of more holistic business models?

A key interest is the extent to which value generated from DSO-Procured services and / or DSO-Enabled services can contribute to holistic business models. This may be supporting the development of DERs to solely profit from DSO-Procured services through contributing additional value (financial, environmental or otherwise) to existing DERs or to improving the underlying business case for a renewable generation project.

Key questions that arose following TP1 are listed below along with the progress made in TP2.

Can monetary value from the delivery of services be shared with other parties – for example the hosts of a participant's DERs?

TP2 developed the TP1 Value Proposition Canvas models that showed how wider value, such as carbon reductions or cost savings, could potentially be created for or shared with other parties for single DER-service operational models. Table 36 provides an update based on the experience of one market participant who operated with a non-standard business model (community energy scheme with DER investment). The net income is calculated using the following approach and any net profit was used for the benefit of the community:

- The costs for capital investment have been excluded.
- The net of transactional costs has been used.
- Costs and income have been considered separately from BaU activities.

Table 36: Details on monetary value corresponding to individual participants

DER	Net Income during TP2	Comment
Portfolio rooftop solar PV - SEPM	£136 loss	The net income excludes the initial investment to retrofit the DERs to be flex-ready. These costs could be reduced in the following areas: • Enablement costs would be reduced if DER flexibility was incorporated into the design process or during natural equipment upgrades. • Control and despatch automation would reduce transactional costs further. • Non-financial aspects may be more attractive from a corporate perspective, e.g. carbon reduction or other CSR benefits.
Ground mount solar PV - SEPM	£189 profit	This was the largest DER participating in TP2 and it used a high-level business model. There is uncertainty whether this DER could act as an "anchor" DER to justify investment in a portfolio-wide control system as there were only two delivery requests. Such an investment could then be used to support the control of other DERs and / or accelerate the deployment of new renewables.
Solar Saver SFN	N/A	This SFN tested the effectiveness of a generation-driven ToUT. The ToUT was used to encourage a shift in demand to align with peaks of solar PV generation installed by the landlord to a block of flats. The trial demonstrated a behavioural demand shift is possible when using vouchers to reward alignment with the ToUT.

Can additional value be created by optimising the use of multiple DERs BTM in the community?

TP2 trials considered the use of two community-based DERs; a battery on a community centre and solar PV installed at a school. The pre-trials operational model was to use the rooftop solar PV as a BTM solution only. An alternative model involving the optimisation of rooftop solar PV with the battery to deliver two DSO-Procured services (SEPM and SPM) was considered. An algorithm was developed to reconcile the operation of the two DERs to determine the viability of such an approach; enabling two small DERs would be costly. Translating the operational complexity of battery charging cycles and solar PV generation was much more complex than the base case. Unfortunately, the algorithm to process the data had not been implemented during TP2. Evaluation could be revisited in the evaluation of TP3.

6.2.4 Key Learnings and Recommendations for TP3

Some specific points for further development have been identified above. For future evaluation, the recommendation is to draw upon and improve the definition of a holistic business model and use this to provide a more systematic appraisal. In TP3 it is also recommended to establish the threshold prices that would make business models viable and socially desirable as well as greater emphasis on peer-to-peer trading via the DSO-enabled services or Smart Community Energy Schemes.

Table 37: Key learnings and recommendations on comparing and contrasting holistic business models

Key Learnings	Recommendations
The term 'holistic business model' has a range of interpretations by different stakeholders and getting the correct definition is vitally important.	Develop the understanding of different business models and define holistic business models to incorporate a wider range of organisational purposes.
A wider range of market actors have been identified but more data and wider experience is required to consider the financial benefits.	Consider the financial benefits for a wider range of market actors during and after TP3.
DERs with low levels of flexibility may require an "anchor" DER to provide the business case for their use and would be more viable if flex-readiness was incorporated into the design of new build projects or when upgrading equipment.	Further consideration should be given as to how automation can reduce transactional costs across the end-to-end process.
The net income from delivering DSO-Procured services from a ground mounted solar PV farm can financially benefit the local community.	Further analysis is required following TP3 trials to determine the effectiveness of this business model and the use of an "anchor" DER to support growth of local renewables.
A ToUT can encourage change of electricity demand so it aligns more with generation profile.	Further analysis is required to assess whether a local ToUT is viable and if so, at what scale.
It may be possible to optimise the use of community-based BTM DERs to create additional value.	The algorithm for data analysis should be continued during TP3 to determine if such optimisation creates additional vale for the community.

6.3 Section Conclusions

Organisations continue to have commercial sensitivities regarding the sharing of their bespoke financial models, as well as the inputs and outputs to these. As a result, there is still a lack of commercial data being collected and shared as part of the Trials. However, the following conclusions have been drawn on the commercial viability of DERs participating in the market:

- The cost base for DERs varies depending on DER type, services to be delivered, alternative opportunities and any lost opportunity. Automation and technology will reduce these costs for a more transactional approach to the market.
- The commercial benefits of participating in TP2 are low and when the participation and opportunity costs, most market participants revealed they made a loss. Feedback from some market participants mentioned that automation will reduce costs of participation substantially and increased portfolio sizes will make participation more profitable.
- The income from Flexibility Services is unlikely to provide an investable business proposition for dedicated DERs but will provide upside for DERs that would improve project returns or increase local community benefits.
- A local community financial benefited from a ground mount solar farm which participated in the Trials.
- The ground mounted solar PV made a profit which indicates that larger DERs could act as an "anchor" DER and fund investment in control of other DERs in the vicinity, making them more

viable This would require an appropriate business model. An alternative route to market is to consider third parties.

- Further work is required to understand the different business models and the economics of providing Flexibility services. This may need wider engagement from market actors given the reluctance of market participants to share information.

7 Technical - DSO

During TP2 the area of technical systems and tools for DSO primarily focussed on:

- further improvement of operational forecasting techniques using real-time data flows.
- expansion of PSA modelling to LV and improvement of methodologies.
- refinement of designs for system coordination tools for TP3 and beyond.

7.1 Learnings from the Development of the WSC-PSA

7.1.1 Improving the Forecasting Modelling

Previous work in TP1 with SIA Partners focused on the development of an operational forecasting methodology and tool for prediction of demand and generation patterns in the hours / days ahead of real-time[29]. The main driver of the calibration of the TP1 mathematical models was historical system data, and a key TP2 improvement of this process was the inclusion of more real-time system data to account for any calibration offsets.

Two sources of real-time data were used to improve forecasting methods:

- SSEN system operational data via the NERDA innovation project automated interface (which provides a real-time view of demand and network flows at EHV level).
- External customer data from a new bespoke API developed by Electralink for the project (provides near real-time view output from embedded generation not directly visible to SSEN).

These real-time data sources were used to develop “volume” and “shape” offsets to models calibrated on historical data to improve the forecast used in power system analysis (PSA) to support flexibility markets.

7.1.2 PSA Modelling and Development

Development of Accurate LV Models

The PSA model work in TP1 focused on the provision of detailed models of the trial area combining EHV and HV network. Many of the flexibility sources in TP1 and TP2 are small DERs connected directly to the LV network. This is important as it is expected future constraints for LCT expansion will occur at

[29] TRANSITION-Load-Forecasting-Dissemination-Report-Final-V3.pdf (ssen-transition.com)

LV level. The modelling work of TP2 was applied to one of the SFNs and resulted in a detailed LV model for the Osney SFN in central Oxford using an advanced PSA tool called DIgSILENT PowerFactory.

LV modelling poses additional challenges compared to traditional power system analysis, including:

- Gaps in the data on the electrical network, including customer phase connectivity.
- Full 3 phase modelling is required to understand any voltage imbalance.
- Detailed time-series data for individual customer loads may be non-existent or may have GDPR privacy concerns associated with its use.

The Osney SFN area (Figure 27) comprises ~ 300 customers supplied by one secondary substation (yellow circle in the middle of Figure 27) with five LV feeders. There is a mix of residential and small commercial customers (some of whom have existing solar PV and EV connections) and a micro-hydro generator (yellow circle in the bottom right hand of **Error! Reference source not found.**).

Figure 27: Osney SFN area in GIS

The methodology[30] followed to develop this LV area model focused on:

(i) developing suitable compatible and bundled electrical models of the LV network,
(ii) allocating individual customer connection nodes and service cables that accounted for individual phase connectivity,
(iii) applying reasonable present and future loading profiles to the model to consider various scenarios that could stress the local network, and
(iv) an assessment of branch loading and nodal voltages under these scenarios.

PSA Algorithm/Tool Testing and Development of Methodology for Sensitivity Factors

The work to date focused on the application of the PSA models in the OpusOne Whole System Coordinator (WSC) tool. The WSC methodology is targeted at not just solving the power flows on the network, but also estimating the required flexibility contract / dispatch amounts simultaneously using an optimisation engine. The suitability of the use of this approach was tested in the TP2 trials through the creation of PSA / Forecast driven flex events.

An alternate method for understanding of the impact of flex dispatch was also investigated using sensitivity factors[31]. These provide a simpler and more robust but less accurate metric than the optimal power flow approach used in the WSC to date. Work was conducted to inform the broader questions around sensitivity factor design and included a literature review, consideration of operational factors, the effect at different voltage levels and how to communicate outputs to a non-technical audience.

[30] A more detailed technical report on this methodology will follow as part of Project LEO deliverable D3.10
[31] **Sensitivity factor**: factors that consider the relative contribution of increased flexibility output to the change in the flow of power on the constrained part of the network.

7.1.3 Further Work on System Coordination Tools

Design of Select/Dispatch and Deployment of PowerFactory

As TP2 progressed, the implementation of the WSC DSO systems and tools primarily relied on manual (as opposed to automatic) user operated workflows. There was also a frequent lack of robustness of the optimal power flow PSA tool to support flexibility market workflows using forecasted (as opposed to scheduled or predefined) trial events.

Two new tools were developed and designed during TP2:

- “Select and Dispatch” tool to automate flexibility contracting and dispatch.
- “PSA+” tool which uses forecasting and PSA to define DSO-Procured events.

These new tools ensured there was suitable learning in key areas (automation of flexibility contracting and dispatch, use of forecasting and PSA to define flex events, etc).

7.1.4 Analysis and Results

Initial analysis has focussed on 13 primary substations with a deeper dive on Rose Hill substation. The work is not yet complete, and the full assessment will be published in Q1 2023.

Improving the Forecasting Modelling and Original Forecasts

The original forecasts used historic data, in TP2 this has been replaced with forecasts based on real-time data with significantly improved accuracy; four forecast methodologies are illustrated in Figure 28.

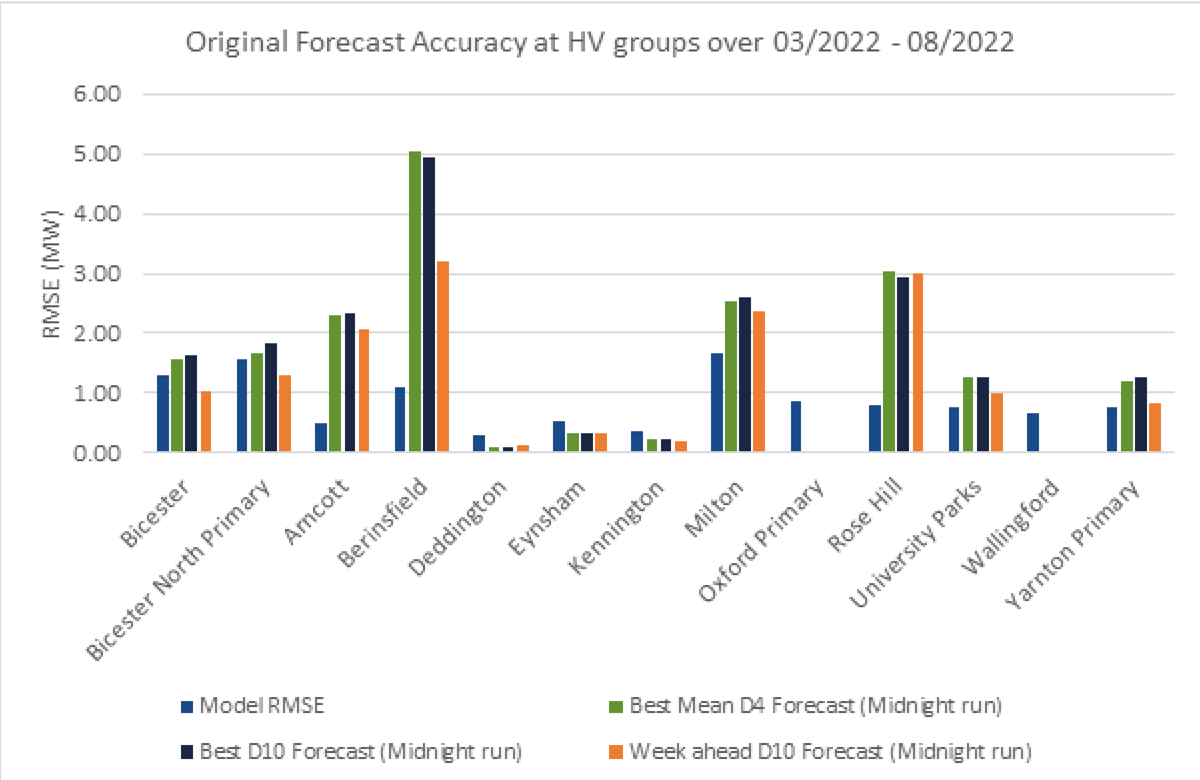

Figure 28: Initial assessment of historical data-based forecast for the 13 Primaries of interest (data issues with Oxford and Wallingford primaries)

Across all substations the best performing forecast methods (relatively to other methods) is the Week-ahead D10 forecast demonstrating best error measure (RMSE) compared to the model error

Initial Accuracy Study of a Real-Time Data Offset Model

The effect of a real-time forecast using an offset for Rose Hill primary substation is illustrated in Figure 29 as follows:

- The blue line is the original forecast based on historic data
- The green line is the forecast based on near real-time data (using within-day corrections) creating an offset model
- The black line is the actual metered network data.

Clearly the green real time model correction provides a much better forecast when compared to the actual metered network data. Further work will extend and deepen the investigation of these issues in the coming weeks across all areas of scope of the trials.

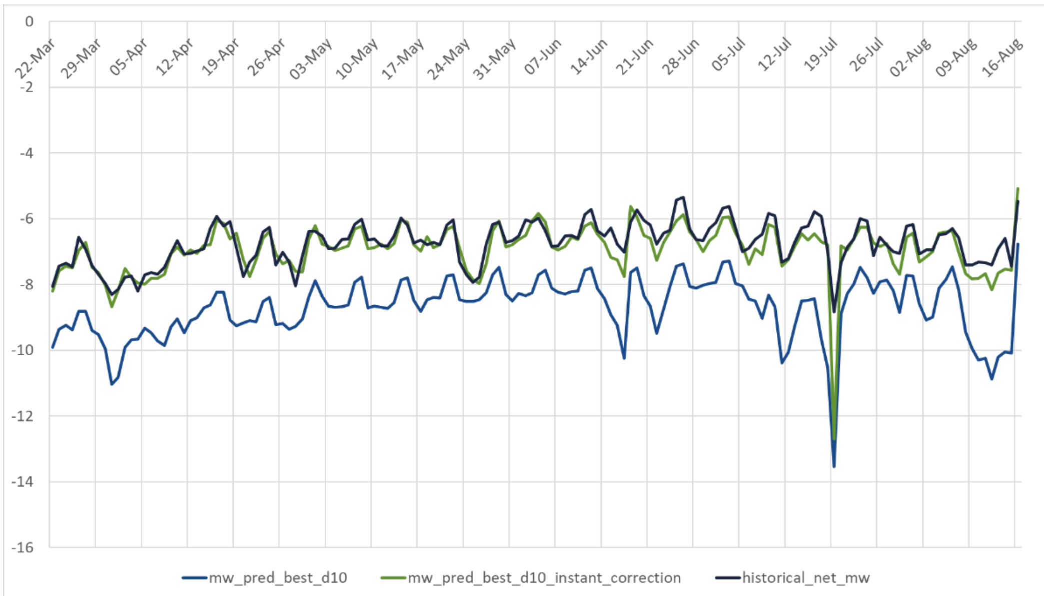

Figure 29: Initial example of a real time data-based correction of the forecast for Rose Hill Primary Comparison of

7.1.5 Results of Additional Work on PSA Modelling and Development

Development of Accurate LV Models

A significant element of the work was to develop an accurate 3-phase network connectivity and electrical model of the LV feeders on Osney island, including individual customer connections. A view of this from DigSilent PowerFactory, is shown in *Figure 30*.

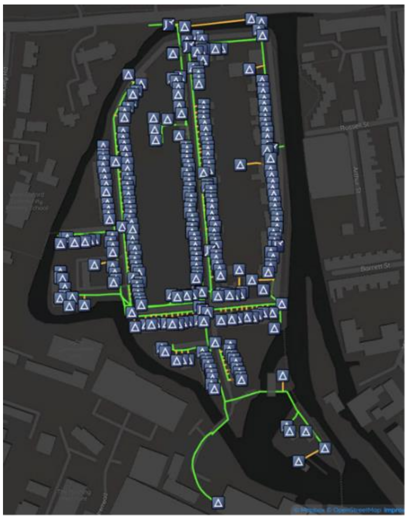

Figure 30: Graphical example of the nodal connection of individual LV customers in Osney

The electrical model above was combined with demand and generation trends for customers and connected low carbon technologies and a full power flow assessment conducted for different scenarios. Figure 31 gives a view of the voltage drop / increase across the LV feeders on Osney Island. There are clearly some long feeders with significant voltage drop, and others with significant voltage rise due to rooftop PV output. These graphs indicate both the challenges facing local SFN areas, but also the additional future value of automated and precise LV modelling methods and capabilities.

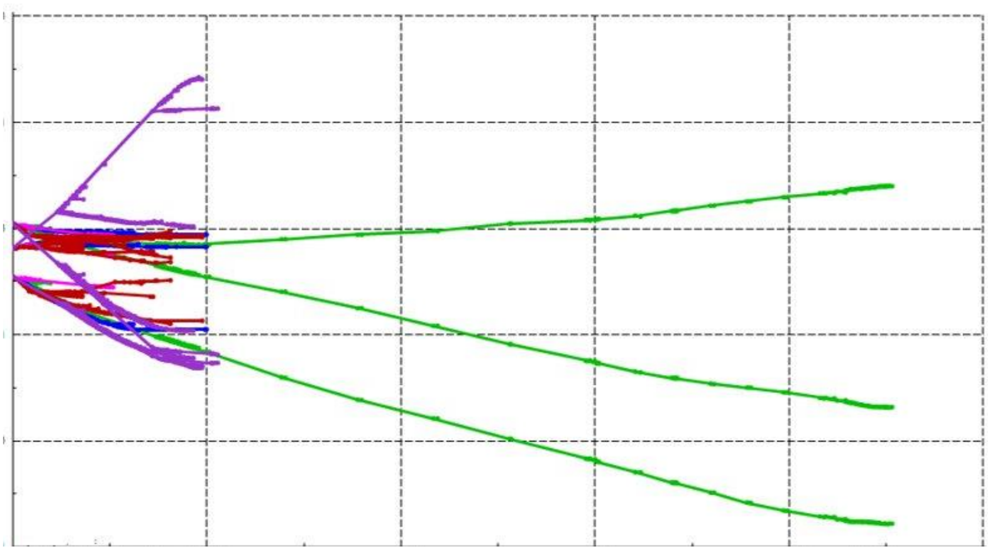

Figure 31: Example voltage profiles on the various LV feeders on Osney SFN for a high generation / low demand case (notable voltage rise on solar LCT dominated feeders)

7.1.6 Key Learning and Recommendations for TP3

The Learnings and Recommendations for future work are summarised in Table 38. Note that full publication of the Real Time Forecasting report from SIA Partners, as well as the Sensitivity Factors report from RINA consulting on the TRANSITION project website in the coming months will provide further context, detail and embellishment of all these elements summarised in this chapter.

Table 38 Key learnings and recommendations on the development of the WSC-PSA

Key Learnings	Recommendations
Historical-data based forecast models can perform well, but may suffer from system/network changes in the intervening period since calibration	Develop real-time correction of historical forecasts to be able to account for shorter term system change
Forecast accuracy determination is a complex and nuanced issue	Consider using a range of accuracy metrics to assess forecast accuracy, e.g. RMS, MAPE, MAPE with zero data points excluded, etc
Detailed local network modelling is required to understand the challenges of LCT deployment and local energy markets at LV.	Develop reproducible and automated workflows to scale LV modelling to other parts of the network
Functionality and data requirements for LV network modelling can be significant	Consider the implementation of PowerFactory to meet these challenges, for unbalanced load flow modelling, and automation of repeatable input/output tasks etc
Synergies between LV field monitoring and LV desktop modelling can improve model outputs	Field based data that allows uncovering of individual customer phase connectivity field data should be prioritised in future
Customer and LCT load profiles are essential for accurate modelling	Assumptions and data sources for these need to improve in future
The sensitivity factors' denominator for thermal constraints should be best defined using MVA (for best balance of technical accuracy and ease of communication/understanding)	Implement MVA as the sensitivity factors denominator for thermal constraints. Use of the MW data flow to indicate a direction of the constraint
Network topology change will drive significant non-linear step changes in the sensitivity factors	Sensitivity factors should be regularly refreshed and tuned to the network topology conditions under study at all times
A sign convention for import/export flex sources and forward/reverse constraints is essential in the sensitivity factor process	Practical considerations are also essential to consider for sensitivity factors e.g. the impact of numerical and decimal place rounding issues in the calculation

7.2 Simulated trials of the ENWL network

7.2.1 Overview

In parallel to the physical trials, SSEN has been working with project partner Electricity North West Limited (ENWL) and consultancy TNEI to develop a methodology for simulated trials. These simulated trials can explore 'what could have happened', and 'what can happen', both for the existing network and any credible future network. They can also address many questions that are not feasible for real trials, such as testing the effects of different approaches to over-procurement and comparing the impact of forecasting algorithms that lead to different types of error structures.

The approach provides synthetically generated data which correspond to ENWL's Distribution Future Energy Scenarios. These are used as inputs to automated processes and tools for decision-making about flexibility as though they were live measurements or forecasts on the real network. The output of the process is simulated flexibility procurement and dispatch decisions. The approach includes randomly generated but realistic forecast errors, contingencies, and failures of delivery to evaluate the impact of the recommended decisions on a model of the network.

Simulations have been run for a simple radial N-1 use case for ENWL's Bold-Kirkby network[32] in which flexibility would be used to manage the flows on a pair of parallel transformers so that, if one of them has a fault, the other will not become overloaded[33]. The requirements for a single evening period on one day, under the year 2050 in the Steady Progression DFES were initially studied.

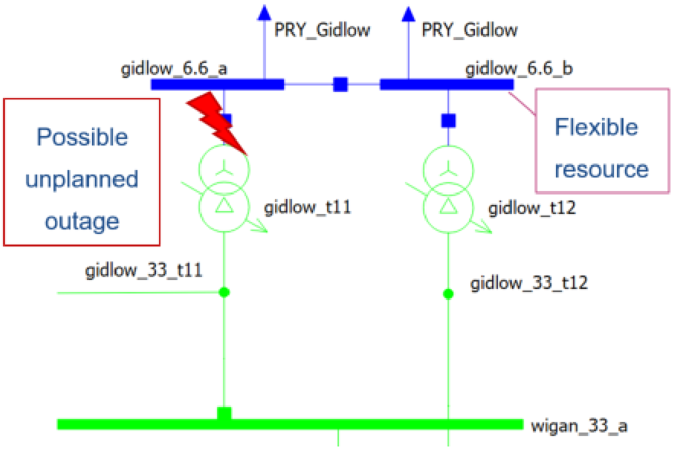

Figure 32: Illustration of the use case considered in the initial simulations

7.2.2 Emerging findings

Monte-Carlo sensitivity analysis was used to consider the impact of uncertainty and errors in the short-term operational forecasts that drive decision-making about flexibility procurement and dispatch. This approach could apply to any decision about flexibility from week-ahead to near-real-time dispatch. The medium-term aspects of season-ahead procurement and the longer-term projections of the DFES are out of scope and have not been considered.

The model describes the uncertainty in demand forecasts[34] which is normalised by the long-run average demand of the relevant primary substation. This means each substation can have a different absolute level of forecast uncertainty but is the same in relative terms. This parameter is the normalised Mean Absolute Deviation (MAD).

Figure 33 summarises some of the outputs of these simulations:

- Probability levels (green, blue, red and purple lines) – these are the coloured lines.
- Normalised MAD values (green line) - 2.5% represents an accurate point forecast (comparable to some recent national demand forecasting work completed by TNEI)[35] with higher values corresponding to less accurate forecasts with a larger uncertainty.

[32] The Bold and Kirkby grid supply point groups, which supply four bulk supply points at Wigan, Orrell, Skelmersdale and Golborne. This network is largely radial, and contains mostly urban and suburban areas.
[33] This would correspond to either the Sustain or Secure flexibility service, depending on the exact definition being used by the relevant DNO and the frequency with which the service is required.
[34] In our initial tranche of simulations, we are only considering constraints arising due to demand.
[35] In principle, it should be possible to characterise the accuracy of actual DSO forecasting tools either by recording pairs of forecast and out-turn values, or by back-casting historic data.

- Flexibility Required (y-axis) - the amount of flexibility required based on that forecast to restrict the probability of an overload to the value indicated by that line. A value of 100% means a DNO should have used twice as much flexibility.
- Median level of over-procurement (purple line) – this shows that if a DSO does not dispatch any flexibility it is essentially 50% probability that a DSO asset will become overloaded (with small values slightly below 0% arising due to the relatively small number of Monte-Carlo samples and a small "buffer" included in the dispatch analysis). This is to be expected since a symmetric distribution of forecast errors is assumed – half the time, the dispatched flexibility will have been sufficient and half the time it will have been insufficient. In practice, DSOs will be much more risk averse, and may only be willing to accept a much lower chance that the asset ends up being overload due to forecast error than is shown here.

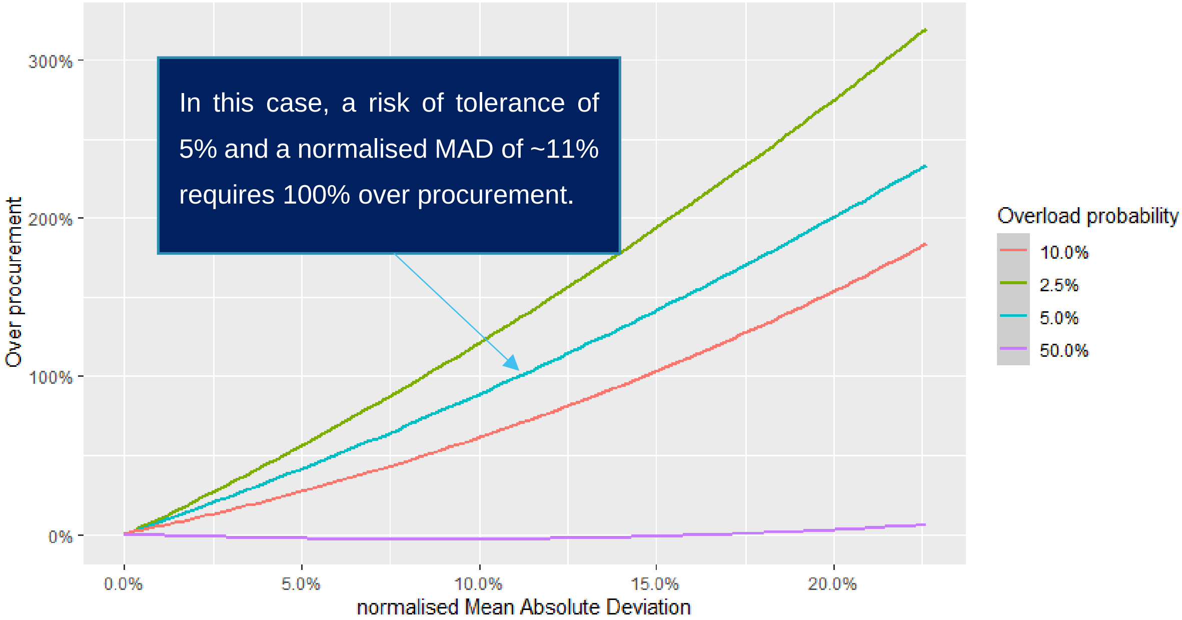

Figure 33: Results showing the necessary change in over procurement with increasing forecast errors

With perfect forecasts (normalised MAD of 0%) the transformer is never overloaded, and the dispatched flexibility is sufficient. With forecast accuracy comparable to national level forecasts, a modest amount of extra flexibility will be needed, although the exact volume depends on the risk appetite of the DSO. However, as the uncertainty in the forecast increases, the over-procurement needed rises significantly.

In practice, the actual extent of the error will depend on the point at which the relevant decisions are being made. In general, errors should diminish closer to real-time, which might mean dispatches can be instructed with relatively little uncertainty, while procurement and contracting decisions (particularly week-ahead decisions) must be made subject to more severe uncertainty.

Another topic considered is the impact of less than perfect reliability of market participants. At this stage of operation, there is relatively limited data available about historic operation of flexibility services to robustly characterise their reliability using probability distributions. A very simple model has therefore been used which can result in either perfect delivery (delivering 100% of the required flexibility), no delivery, or partial delivery, and explored this through sensitivity analysis.

7.2.3 Discussion and next steps

These results summarise some of the early findings from the simulations, for a single network model, single flexibility use-case, and focusing on a single constrained evening period during one future scenario. In the coming months, the scope of these studies will be expanded to look at a wider range of network conditions, and additional use cases.

7.2.4 Key Learning and recommendation for TP3

Table 39: Key learnings and recommendations on simulated trials of the ENWL network

Key Learnings	Recommendations
To manage the uncertainty of delivery, DSOs will need to over-procure flexibility against the target level and this will result in lower prices as there is a fixed budget.	Industry needs to consider what an acceptable risk appetite could be, or what methodology might be appropriate for setting this.
Initial results suggest that the operation of the flexibility is very sensitive to the level of uncertainty in the forecast, or to the success rates of providers.	DSOs should assess the performance of their forecast tools to understand uncertainty and (where possible) use historic data on delivery to understand reliability.
DSOs will have to determine whether to procure flexibility ahead of time when there is uncertainty about outcomes or nearer real-time when there may be little or no flexibility available.	Consider how actual forecast uncertainty and unreliability change in the run-up to the delivery of the service, and, if possible, quantify how the costs of flexibility and the availability of services might change at different lead-times.
DSOs can over-procure modest levels of flexibility to address partial unavailability / delivery shortfalls whereas complete unavailability / non-delivery is likely to require higher levels of flexibility. Diversifying the supply of flexibility may provide some mitigation.	DSOs should consider how to account for reliability in procurement and operations, especially as flexibility markets will comprise a small number of larger providers until they mature.

7.3 Section Conclusions

In TP2 the projects continued their work with SIA Partners to improve the operational forecasting methodology and started working with project partner Electricity North West (ENWL) and consultancy TNEI to develop a methodology for simulated trials. The following conclusions have been made:

- Real-time model data is likely to provide improved forecast compared to the actual metered network data.
- A detailed LV model for the Osney SFN in central Oxford has shown the significant voltage drop / increase across various LV feeders in the area due to the length of these feeders and the rooftop PV output. These results indicate both the challenges facing local SFN areas, and the future value of automated and precise LV modelling methods and capabilities.
- The simulated trials show that uncertainty will be an almost inevitable feature of flexibility markets. DNOs will therefore need to “over-procure”, buying additional flexibility (which they

are unlikely to need). However, the available budget – as set by reinforcement – will not change. This will effectively reduce the maximum unit price for flexibility services.

- Uncertainty about forecasts and provider reliability will probably reduce closer to real-time, which might encourage a DSO to wait if possible before making decisions. However, this needs to be considered against the need to act early enough to ensure there are flexible resources available and contracted, which might otherwise end up providing services elsewhere (e.g., to NGESO) or, if looking several years ahead, may not be built.
- When it comes to reliability, initial results suggest that partial delivery could end up being a much easier phenomena for a network operator to manage, with modest amounts of over-procurement proving to be relatively effective. However, complete unavailability of a market participant could be much more difficult to manage and could essentially require a DSO to contract the same service from two different providers. This might be even more challenging in the case where a DSO contracts with several providers, but there is some statistical dependency in their availability, such that, when one is not available, the others are also less likely to be available.

Appendix A: Glossary of Additional Terms (added during TP2)

The Glossary of Terms for the LEO project can be found here.

Additional Terms used by the TRANSITION project can be found here.

There are some terms used in this document that do not yet appear in the Glossary of Terms. Working definitions are provided below:

Term	Definition
ANM	Active Network Management
API	Application Programming Interface
BaU	Business as Usual
BMR	Basic Market Rules
BTM	Behind the Meter
CBA	Cost Benefit Analysis
CEM	Common Evaluation Methodology (i.e. ENA Tool for Network Investment Decisions)
DCM	Dynamic (DSO) Constraint Management
DSR	Demand-Side Response
ENA	Energy Networks Association
EV	Electric Vehicles
GIS	Geographical Information System
LCT	Low Carbon Technologies
MAD	Mean Absolute Deviation
MEC	Maximum Export Capacity
MIC	Maximum Import Capacity
MPAN	Meter Point Administration Number
MSP	Market Stimulation Package
NPV	Net Present Value
ON – P	Open Networks Project
PPS2.0	People Power Station
PV	Photovoltaics
SCR	Secure (DSO) Constraint Management
SDA	Same-Day Adjustment
SEPM	Sustain Export Peak Management
SFNs	Smart and Fair Neighbourhoods
SLD	Single Line Diagram
TCV	Total Contract Value
TP1	Trial Period 1
TP2	Trial Period 2
TP3	Trial Period 3
V2G	Vehicle-to-Grid

Appendix B: Summary of Round Table Discussions

The workshop included two round table discussions. In the first-round table discussion the participants explored the interactions between their assigned role and the **planning role** of the DSO.

Who has the responsibility to produce the Local Area Energy Plan?
• main responsibility with both the Local Authority and the DNO • many parties are directly impacted and can provide critical input • there is scope for main lead and secondary lead • implementation should be combination of top-down and bottom-up: the national government should produce a blueprint framework that can be localised for individual LAEPs, while empirical data available at local data should feed into bottom-up forecasting models • there is asymmetry or reasons for getting involved: some organisations have an obligation to take a certain role, while vested interests may motivate others • ensuring neutrality becomes critical; this can be financed by a collaboration of gas and electricity networks
What other institutions should feed into or support the Local Area Energy Plan and how?
• relevant stakeholders include the gas and water networks, (commercial and residential) construction industry, district heating providers and major employers, social landlords, community groups • stakeholders can provide critical input: for example, environmental agencies can provide information on areas with expected high heat episodes and the construction industry can use this information in including appropriate insulation in the development projects
How does the Local Area Energy Plan interact with national and strategic planning including transmission - distribution planning?
• the interaction is assumed to follow a combined top-down / bottom-up approach; for example, participants expect funding to be provided top-down, while data on localised needs will be provided bottom-up • a bottom-up approach is needed to ensure increasing convergence, as the process advances • aggregate outputs from all LAEP will need to feed into national infrastructure development

In the second round table discussion the participants explored the interactions between their assigned role and the market facilitator and real-time operations roles of the DSO.

What elements of the ESO / FSO and the DSO flexibility markets should be standardised, e.g. contracts, services, delivery windows, time horizon?
• most of them, e.g. delivery windows, procurement and time horizons • standardisation reduces cost and time (e.g. by removing the need for external interpreters or the time to approve the FSA by different participants) • elements to particularly benefit from standardisation include: contracts, baselining methodology, market platform, network data platform, interface, terminology in particular • standardisation increases the ability to transact with multiple parties • introduction of framework contracts is very welcome, to allow for a certain degree of flexibility
What data and information should the DSO provide to market participants to enable them to make informed decisions on participation in LV flexibility markets and increase market liquidity?
• due to early stage of the market, there is not a consolidated historical database. For this reason, there is considerable uncertainty on optimal bids for utilisation and availability

• all data that reduces uncertainty is welcome, e.g. total capacity in a given area, historical participation profiles of different assets, cost savings due to the flexibility provided, information on constrained substation etc.
How can we ensure a fair price for flexibility that reflects its value to the network and system (including stacking of services) without overburdening network customers?
• fair price is proportional with cost savings due to deferred reinforcement • weight of operational costs is important to both the DNO and providers; the current rates that providers receive do not support the business case • fairness is defined differently to different stakeholders: DNOs, providers, customers

Appendix C - Key Learnings and Future Recommendations

Key Learnings	Recommendations
APIs improve the experience for market participants and enable services to be dispatched, instructed, and delivered in a timely manner, particularly those services that have a short notice period.	Review the use of APIs during TP3 to determine where these are required to lessen the burden on market participants.
The current baselining methodologies are not appropriate for all DER types.	Continue to determine the most suitable baselining methods for different DER types to inform TP3 and beyond.
A local community has financial benefited from the Trials via a ground mount solar farm which participated in the SEPM service.	A full analysis should be undertaken following further trials in TP3 to determine the validity of this business model and whether such DERs would be sufficient to provide the “anchor” DER that establishes a business case for investment in a portfolio-wide control system, thus enabling small scale flex, thus accelerating renewable deployment.
The limited data from TP2 indicates that the commercial benefits of participating in the trials are low; however, the non-financial benefits are recognised by market participants.	Engage with market participants to determine their financial and non-financial benefits of participating in the Trials. Consider how wider social value can support the acceleration of new flexibility and the delivery of the outcomes achieved by DSO-Procured and DSO-Enabled services.
A detailed understanding is needed of the Flexibility requirements to understand the benefit to the DSO.	Applying probabilities to each demand scenario and using these to calculate the weighted average NPV will identify the optimal length of a contract. Using this contract length and the least worst regret intrinsic value to calculate the price ceiling reduced the risk to the DSO of a demand varying from the prediction.
There were very few submissions via the BMR self-reporting mechanism, suggesting the BMRs were not actively used by market participants during TP2.	Hold a workshop during TP3 to discuss the wider application of BMRs and the appropriate contractual arrangements for all market participants.
The CEM provides a value for substation reinforcement and the included carbon reductions from deferred reinforcement.	A higher level of liquidity is required for a CBA to draw meaningful results, although this could be achieved by determining the breakeven price and comparing to market prices.
It is unclear what is and is not included in the CEM and whether it is an appropriate model to adequately value flexibility.	Consider shortcomings of the CEM, how they can be overcome or addressed and whether they would make a meaningful difference for DSO-Enabled services.
The outcome of the Strategic Code Review on new connections is expected to increase curtailed connections.	Market participants to consider the consequences of the SCR work.
The availability / utilisation price split differed depending on the service, DER type and market participant.	Engage with market participants more to understand their motivations for the pricing.
The work to simplify the language and reduce the length of the contractual documentation was welcomed by those who reviewed the changes; however, this still presents a barrier to participating for market participants with DERs with lower levels of flexibility or smaller portfolios.	Further engagement is required to establish what further changes could be made to enable easier market access at a low overall burden.
Small scale DERs may require an “anchor” DER to provide the business case for investment. Enablement costs may be less of a hurdle if flex-readiness is built-in to the design of new build projects or opportunities are taken when upgrading existing parts such as inverters.	Opportunities to reduce costs for small scale DERs should be explored.
There is no standard definition of non-traditional market participants and DERs.	Define non-traditional market participants and non-traditional DERs and look for mechanisms to incentivise energy efficiency.

Key Learnings	Recommendations
Across all DSO-Procured services, different DER types demonstrated occasions of over-delivery, under-delivery, and delivery in the opposite direction to the service need, which increased the network need for flexibility.	Gather further evidence of delivered capacity by DER type for a range of DSO-Procured services, conditions and approach by market participants.
Forecasting the amount of flexibility available from smaller non-traditional DERs can be challenging.	Review the forecasting methods and how they can apply to non-traditional DERs to improve accuracy of availability and reliability of delivery from a portfolio.
The term 'holistic business model' is not interpreted identically by different stakeholders and so defining terms in any given context or analysis is important.	Further development of the framework for defining and understanding different levels of business model drawing upon engagement with partners.
Increasing competition and liquidity in flexibility markets can reduce prices but the illiquid nature of the auctions meant the offered capacity in auctions was almost always less than the requested capacity and the price cap prevailed.	Discuss with BaU to determine what value the project can add, e.g. reduce the request capacity to near or below the available DERs to increase liquidity and create opportunities for learning from competitive bidding.
There have been too few MIC / MEC, DCM and SCM auctions to support meaningful analysis.	Test DSO-Enabled services with more trades and an increased number of participating market participants (or find an alternative means to address the issue). Determine what value the project can add to DCM and SCM, e.g. range of DERs, availability / utilisation price variations, and increased changes to the service window (and more auctions at each).
A market model based on a central platform interacting automatically with a satellite platform (and vice versa) worked well for DSO-Procured services but is uncertain for DSO-Enabled services.	Ensure that the option of using the Piclo platform is highlighted to all market participants to increase utilisation, where possible.
There are additional technical challenges to be overcome in relation to the ongoing development of the NMF and Piclo platforms and the user experience of the platform could be improved.	Ensure future developments for the user experience of the NMF platform are captured to progress into any business-as-usual platform. This includes automation across the end-to-end process, P2P settlement and verification process for all parties and include inbuilt methods to help users navigate and use the platform.
Early data indicates the reliability varies by DER type with battery and solar PV having higher reliability than EVs, V2G and DSR	Investigate how the reliability model can be improved to consider more of the variables affecting delivery; this may consider derating to improve delivery certainty.
Some DERs had a high risk of non-delivery compared to others, e.g. battery and solar PV versus DSR and V2G.	Determine if there are underlying reasons for this, if alternative forecasting solutions would help and if the risk reduces with experience.
Unavailability is likely to affect the attractiveness of some DERs and DSO procurement strategies.	Conduct further testing and analysis to understand unavailability across a range of DER types, auction timescales and DSO-Procured services, and continue discussions on who should hold reserve and the wider issues at lower voltages.
Non-traditional market participants will often not have the time or resources to understand flexibility services and flexibility markets and may benefit from alternative routes to market.	Review the resources developed to support market participants (particularly LEO deliverable D3.9) and consider the publication of a readily-understood user guide for non-traditional market participants. Encourage engagement between aggregators and market participants to determine if this is a viable alternative route to market.
There is a lack of skilled internal resource to manage the different stages of the end-to-end processes as BaU requirements affect availability of personnel. It is uncertain if the inclusion of two third-party aggregators will improve matters.	It is proposed this area is further evaluated following TP3 and it is hoped that this will include recommendations for future consideration.
Market participants who expect to participate in auctions for a service prefer week-ahead auctions as it avoids the workload of day ahead auctions and the long-term risks of season-ahead auctions.	The pricing implications and risks associated with different time horizons for different DER types and market participants needs to be further tested in TP3 across all products (including the stacking of these products).

Key Learnings	Recommendations
Improved training, including on-the-job training, has greatly improved the understanding of all market participants.	Training should be reviewed and continued throughout TP3.
The availability of V2G chargers is affected by the unpredictable behaviour of the EV users which results in an unpredictable response. This issue does not appear to exist with the EVs not connected to a V2G charger.	Engage with market participant with V2Gs to explore how availability and performance can be improved. Engage with EVs not using V2G chargers to determine if there are behaviour improvements that would benefit the market participant with V2G.
The timing of DSO-Procured services can make a service attractive to EVs and V2G portfolio, e.g. if EVs and V2Gs are not plugged in at the service delivery time they cannot participate.	The impact of scaling up the number of chargers in a portfolio should be investigated in TP3 to determine if this affects the risk of under-delivery.
TP2 trials included operation of one participant's behind the meter battery and solar PV at Rose Hill Primary School in Oxford. Reconciliation of the battery's operation as compared to the school's demand and solar generation was complex and the algorithm to process the data had not been implemented in time for data to be available in TP2.	Evaluation of that trial should be revisited in the evaluation TP3.
Detailed local network modelling is required to understand the challenges of LCT deployment and local energy markets at LV.	Reproducible and automated workflows are critical to scale LV modelling to other parts of the network
Customer and LCT load profiles are essential for accurate modelling.	Assumptions and data sources for these need to improve in future
Synergies between LV field monitoring and LV desktop modelling can improve model outputs.	Field based data that allows uncovering of individual customer phase connectivity field data should be prioritised in future
The sensitivity factors' denominator for thermal constraints should be best defined using MVA (for best balance of technical accuracy and ease of communication/understanding).	Sensitivity Factors also need the use of the MW data flow to indicate a direction of the constraint
Network topology change will drive significant non-linear step changes in the sensitivity factors.	Sensitivity factors should be regularly refreshed and tuned to the network topology conditions under study at all times
A sign convention for import/export flex sources and forward/reverse constraints is essential in the sensitivity factor process.	Practical considerations are also essential to consider for sensitivity factors e.g. the impact of numerical and decimal place rounding issues in the calculation
Initial results suggest that the operation of the flexibility is very sensitive to the level of uncertainty in the forecast, or to the success rates of providers.	DSOs should assess the performance of their forecast tools to understand uncertainty and (where possible) use historic data on delivery to understand reliability.
DSOs will have to determine whether to procure flexibility ahead of time when there is uncertainty about outcomes or nearer real-time when there may be little or no flexibility available.	Consider how actual forecast uncertainty and unreliability change in the run-up to the delivery of the service, and, if possible, quantify how the costs of flexibility and the availability of services might change at different lead-times.
Historical data based forecast models can perform well, but may suffer from system/network changes in the intervening period since calibration	Real-time correction of historical forecasts is essential to be able to account for shorter term system change
Forecast accuracy determination is a complex and nuanced issue.	A range of accuracy metrics may be required to assess forecast accuracy, e.g., RMS, MAPE, MAPE with zero data points excluded, etc.