TRANSITION & PROJECT LEO

Market Trials Report (Period 3)

March 2023

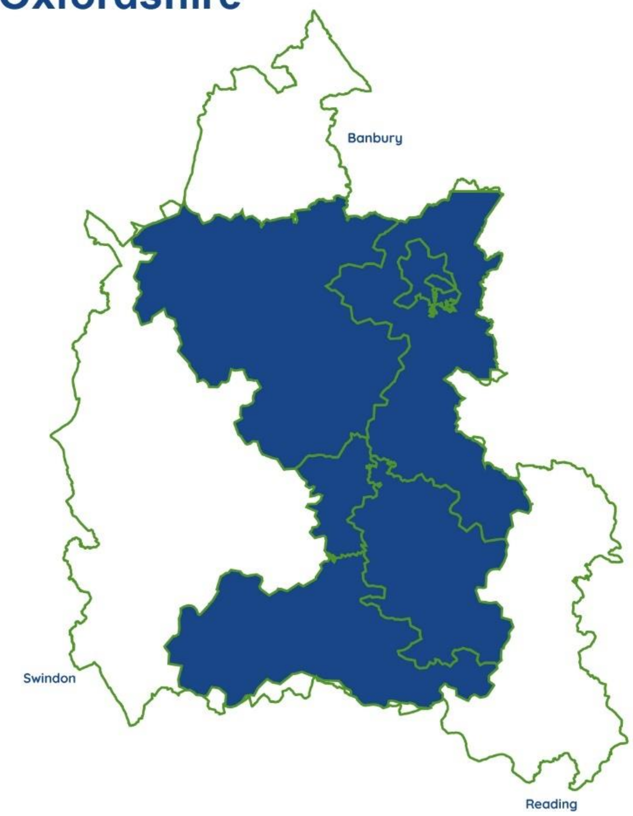
transition
Moving to a smart future

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.

Local Energy Oxfordshire

Moving to a smart future

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.

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.

[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/

This report focuses on Trial Period 3 (TP3), building on the learnings from TP1[3] and TP2[4] and informing and informing the future of Business as Usual (BaU) services. Through TP3, the focus has been increasing market participants' involvement (both traditional and non-traditional Distributed Energy Resources (DERs) and organisations) and gaining feedback on the variety of products and services available, including:

- An increased number of auctions across all service types – significantly more auctions were run for the Dynamic Constraint Management (DCM) and Secure Constraint Management (SCM) services.
- An increased number of procurement horizons – season ahead and week ahead auctions were introduced for the SCM service; and week ahead and day ahead auctions were introduced for the Trading Import Capacity (Exceeding MIC) and Trading Export Capacity (Exceeding MEC) services.
- Auctions were run at Primary Substations – market participants could participate in an auction at primary level for the SCM, Sustain Export Peak Management (SEPM) and Sustain Peak Management (SPM) services.
- Market Participants could stack services - market participants could stack SCM with SPM services as per the Flexibility Service Agreement (FSA).

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:

Improving market accessibility for customers and communities: Feedback from TP3 suggests the number, complexity and length of the contractual arrangements still presents a barrier to participation. In conjunction with the FSA (based on the ENA's common Flexibility Services Agreement), during the project Trials a framework-style contract was used which allowed market participants to participate in individual auctions without the requirement to sign additional contracts. This was effective in allowing SSEN to procure flexibility over shorter timescales and closer to the point of need and should be considered going forwards.

Increasing market liquidity: In TP3, market participants found that utilising a 'whole portfolio approach' and automation can improve the business case for participating in DSO flexibility services. Familiarity, automation, and a commercial market with more market participants would substantially reduce costs and change the economics of participation. Further, the ability to stack different revenue streams is imperative for a liquid market in which both market participants and the network can benefit. However, market participants found it difficult to stack different revenue streams during TP3. The exclusivity clauses and primacy rules required across all markets should be considered to ensure market participants can stack different revenue streams.

[3] Ofgem-Report-Trial-Period-1.pdf (ssen-transition.com)
[4] TP2-Ofgem-Report-v1.pdf (ssen-transition.com)

Trialling types of flexibility services and dispatch of DERs: Initial data from the TP3 trials suggests that the liquidity at primary market is typically much higher when responses are received, however 50% of primary auctions received no responses. Liquidity is less likely to be zero at BSP, but the liquidity is much lower. Whilst this data is informed by a small number of 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 mean estimated reliability score, per asset type, was low. This suggests that, on average, assets in TP3 likely only delivered a small proportion of what was requested of them. 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. More simple and accurate baseline model should be explored to those currently used in the Project Trials, in particular the Meter Before and Meter After approach. Alternatively, the DSO should consider whether baselining is a requirement for DSO services in BaU, as the value from such services may not merit validating services in this way.

This report gives a flavour of the challenges overcome developing the local market for flexibility in the Oxfordshire area. Following TP3, the projects will undertake a Technical Trial to gain further feedback on market participants and DERs’ ability to meet networks’ needs.

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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.

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 SLES to maximise economic, environmental, and social prosperity for the region.

Project LEO and Project TRANSITION are conducting joint trials to maximise the learnings from local flexibility markets in Oxfordshire during three Trial Periods[5]. This report focuses on TP3, building on learnings from TP2[4] and TP1[3] and informing the future of BaU services. A comparison is provided in Table 1.

TP3 saw an increased number of market participants, procurement horizons, and locations whilst allowing market participants to stack services as per the FSA. These changes provided learnings with respect to informing the optimal market structure and how to engage with the wider market going forward.TP3 ran for 17 weeks from Nov-22 to Feb-23. This report summarises the learnings and recommendations from this period.

Table 1: Summary of changes in TP3 compared to TP2.

Area	During TP3	During TP2
Procurement Horizons	**As per TP2, plus:** • **Season Ahead**: SCM • **Week Ahead** - SCM, Exceeding MIC and Exceeding MEC • **Day Ahead** - Exceeding MIC and Exceeding MEC	**Season Ahead** - SPM, Exceeding MIC and Exceeding MEC **Week Ahead** - SPM and SEPM **Day Ahead** - SPM, SEPM, DCM and SCM
Geographical Coverage	**6 Bulk Supply Points (BSPs)** - Bicester North, Cowley Local, Oxford, Drayton, Headington and Witney-Yarnton **4 Primary substations** - Bicester Primary, Bicester North Primary, Kennington Primary, Rose Hill Primary	**6 BSPs** - Bicester North, Cowley Local, Oxford, Drayton, Headington and Witney-Yarnton
Stacking Services	SCM and SPM	N/A
Total Auctions	DSO-Procured:255 DSO-Enabled:17	DSO-Procured:116 DSO-Enabled: 8
Total Events	DSO-Procured:279 DSO-Enabled: 0 (no physical delivery)	DSO-Procured: 93 DSO-Enabled:2 (no physical delivery)

[5] 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)

2 Routes to Market

2.1 Alignment of Services and Products

The number of auctions and contracts accepted for each product trialled during TP3 are summarised in Table 2. As per TP2, the number of successful contracts per auction suggests market participants preferred to participate in week-ahead auctions. This could be because these provided the optimum balance between DER output certainty and effort.

Table 2: Services and products procured in TP3 with number of auctions and resulting contracts.

	Product timeline					
	Season-ahead		Week-ahead		Day-ahead	
Service	Auctions	Contracts	Auctions	Contracts	Auctions	Contracts
SPM	6	0	57	56	24	21
SEPM			16	15	30	3
SCM	6	3	56	57	24	3
DCM					36	25
Exceeding MEC			10	0	1	0
Exceeding MIC	1	0	4	0	1	0

A wide variety DER types participated in auctions for the services in Table 2, each with different operating characteristics and participating in different products and services; see Appendix A for details (including request fulfilment). This analysis shows that all DERs participated in the SPM and SEPM services, Solar PV did not participate in the SCM and DCM services, and hydro did not participate in DCM[6]. The following learnings have been captured:

- **Heat Pump**: Minimal flexibility as they operate most efficiently when running at a continuously low baseload but there is an associated reduction in demand on the network.
- **HVAC:** Minimal flexibility (more in summer, less in winter; both need further exploration) and short duration of usage (~0.5 hours) as there is a need to maintain temperatures within a narrow comfort range. There may be ethical and environmental implications of using HVAC to provide services when the building is unoccupied which should be explored further.
- **Residential DSR:** The level of flexibility available varied on a weekly basis due to external factors; EVs have high variability due to driver behaviour but fridges have low variability as static devices. This affected forecasting the level of flexibility available which impacted the use of the portfolio.
- **Hydro**: Flexibility is dependent on rainfall and can be unpredictable and intermittent which makes this DER more suited to Exceeding MEC and Exceeding MIC services or used in a Smart Community Energy Scheme (SCES) arrangement (see Section 6.1.1).

The ability to participate in an auction at primary level was introduced in TP3 for the SCM, SEPM and SPM services. As shown in the Table 3, participants were more likely to participate in the BSP auctions

[6] Although the hydro participated in several auctions across the different services, this DER did not dispatch flexibility due to ongoing issue at the site.

compared to primary auctions although the proportion of the requested capacity delivered was higher for primary auctions. This is likely due to the approach used by SSEN who kept the requested capacity significantly higher than the flexibility available to ensure all DERs could participate.

Table 3:Summary of auctions at BSP and Primary (PRI) level in TP3

Service	No of Auctions		Sum of Request Quantity (kW)		Successful Auctions (Weighted Average)[7]		Request Fulfillment (Weighted Average)[8]	
	BSP	PRI	BSP	PRI	BSP	PRI	BSP	PRI
SCM	74	12	13474	534	35%	17%	1%	3%
SEPM	42	4	-14397	-210	26%	0%	4%	0%
SPM	72	15	11952	694	43%	27%	2%	11%

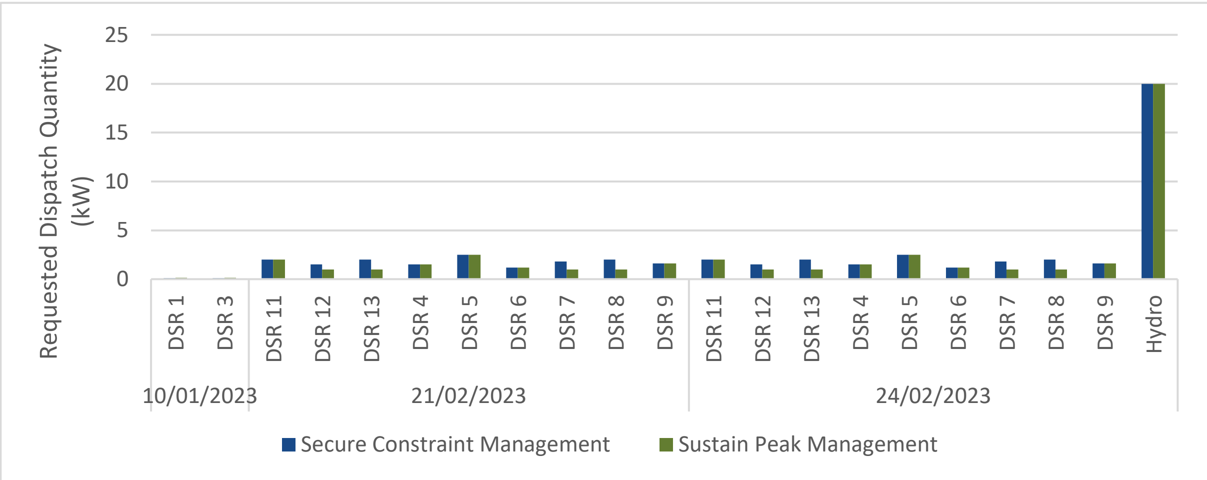

Figure 1: Stacking services in TP3.

The ability to stack services was introduced in TP3; there were three opportunities to stack SCM with SPM and, as illustrated in Figure 1, only DSR and hydro DERs stacked these services. In most cases, the flexibility requested from each DER was the same for both services; however, in eight of the ten occurrences when the flexibility requested was dissimilar, more was requested for SCM.

As discussed in the Commercial Findings Workshop Report[9], the ability to stack different revenue streams is imperative for a liquid market in which both market participants and the network can benefit. However, market participants found it difficult to stack different revenue streams during TP3:

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[7] Percentage of auctions in which at least one market participant responded to the request, weighted across the total number of auctions held across the BSPs or Primaries for each service.
[8] Percentage of request quantity met via a response, weighted across the total amount requested across the BSPs or Primary for each service.
[9] See “Commercial Findings Workshop Report” dated 28th March 2023 [Library | SSEN Transition (ssen-transition.com)](ssen-transition.com)

- The ongoing connectivity issues with the community battery and issues with the hydro limited their opportunity to participate in TP3 and stack services.
- The community battery has limited flexibility (16kW) to stack across different services and it was considered the financial reward would not outweigh the effort required.
- An aggregator was unable to stack DSO and ESO services due to the exclusivity required for the ESO service; they opted to deliver the ESO service as it was more profitable.

Table 4: Key Learnings and Recommendations the Alignment of Services and Products

Key Learnings	Recommendations
Exclusivity clauses reduce the ability of market participants to stack DSO and ESO and could distort the market or cause market participants to lose out financially (particularly availability payments).	Determine the barriers that impede aggregators from stacking different revenue streams and whether this would affect the payment of services using availability payments.
Participants were more likely to participate in the BSP auction compared to the primary auction; however, the proportion of the requested capacity delivered was higher across the primary auctions.	Considering the benefits and costs required to run auctions at different voltage levels and determine if there is an optimal level at which the DSO should procure flexibility.
When stacking services, DERs may be likely to offer and dispatch more capacity for the higher-paying service to maximise their financial returns.	Consider the price ceiling and structure for different services to determine how this may affect the procurement / delivery of stacked services.

2.2 User Experience of Market Platforms

Two APIs were developed in TP3; one to send delivery instructions from the NMF to Piclo platform and the other to send instructions from the Piclo platform to market participants.

During TP3 additional functionality was added to enable all DSO Procured Services to run on either the NMF or Piclo platform. Initially this meant those who used the Piclo platform consistently during TP1 and TP2 had to switch to the NMF in TP3, affecting the use of the Piclo platform in TP3. However, all partners indicated the implementation of the APIs improved their experience and that participation in TP3 was comparatively easy compared to TP1 and TP2. Market participant feedback on the NMF and Piclo platforms can be summarised as:

- The registration process focusses on the NMF which is more developed that the Piclo platform and encourages market participants to prioritise this route to market.
- The development of Exceeding MEC and Exceeding MIC was de-prioritised on the Piclo platform due to difficulties experienced whilst implementing the DSO-Procured services and their perception of limited future market opportunity.
- APIs design is simplified if the two parties have the contractual mechanisms or relationships to enable the fast implementation of solutions.

- Some DERs were not automated enough to benefit from the APIs.

The following APIs should be considered in BaU to lessen the transaction time for market participants:

- An API to automatically submit bids from a market participant's DER scheduling system, although this requires the ability to determine the available flexibility and bidding strategy to maximise the benefit.
- An API to upload meter data to the NMF in the correct format and calculate the settlement to improve the existing settlement process, which is inefficient and, at times, would reduce human errors as there is less handling of data.
- An API to check whether a household / user is participating in services via another aggregator.

Table 5 - Learnings and Recommendations from User Experience of Market Platforms

Key Learnings	Recommendations
APIs improved the experience of market participants.	Review the above APIs and determine the costs and benefits to developing these.
Delays in developing APIs to integrate with satellite markets may reduce their attractiveness.	Publish and advertise a technical specification to enable alternative platforms to integrate with the NMF.
Back-end data is visible to market participants on the NMF. Although this information is useful to the DSO, it is not useful to market participants and makes the NMF more cumbersome to use.	Review the information available to market participants and streamline the platform, so that different market actors are shown only data that is relevant. This would ensure that it is more user friendly and pertinent to the delivery of services.
When interfacing technology provided by multiple suppliers it can be challenging to agree a common method/standard. This can result in delays in delivering solutions.	To work more effectively with partners, early engagement is required to ensure a joined-up approach. Industry standardisation for interfacing technology would drastically improve efficiency and speed at which systems could be interfaced. Regulator and key industry actors need to agree a common approach to prevent further inefficiencies and speed up the ability to achieve net zero.
Different technologies (NMF and Piclo) are structured differently, which can create challenges when FSPs upload their DERs. To address this, changes were made to the API to allow for specific assets to dispatch.	When developing different platforms, it is important to consider the entire picture, identify differences, and collaborate to agree a standardised approach.

2.3 Contractual Documents

2.3.1 Learnings on Flexibility Services Agreement

During TP3, a two-part workshop was held by SSEN and Baringa on Commercial Findings from the TRANSITION trials[9]. During these workshops, trial participants fed back that the FSA would be considered a significant barrier to participation in flexibility services in Business as Usual, with two participants stating that they would not have signed the FSA in BaU. Participants raised issues with the length, complexity, and level of liability posed by the document. Some terms were also deemed not appropriate for aggregators, specifically residential demand aggregators whose management over domestic sites will be limited. It is worth noting that the FSA used by SSEN in TRANSITION, is an already 'slimmed-down' version of the ENA's 'Standard Agreement for procuring Flexibility Services ON21-WS1A-P4'.

Potential participants who do not view flexibility provision as a core part of their business model are particularly likely to be put off from participation by a lengthy and complicated document, or by needing to accept high levels of liability and take out expensive insurance.

Although the contractual agreement used in the TRANSITION trials was based on the ENA's common Flexibility Services Agreement (as stated above), a framework-style contract was used which allowed Flexibility Service Provider's (FSPs) to sign on to an over-arching agreement and then take part in individual auctions without the need to sign additional contracts (compared to in BaU where the FSA needs to be signed for each individual auction participated in). This was effective in allowing SSEN to procure flexibility over shorter timescales and closer to the point of need in TRANSITION, however as noted above, even this simplified contractual arrangement was seen as a barrier to participation by some FSPs. A suggested next step based on these learnings is therefore to feed this back to the ENA and suggest potential modifications to their common FSA in future.

Table 6 - Learnings and Recommendations from Contractual Documents

Key Learnings	Recommendations
The level of risk and level of liability in the standard industry contracts for distribution flexibility services is considered too high compared to the potential value of the contracts.	The level of liability and burdensome clauses should be reconsidered in context of the value of the contract. If the clauses are essential for system security but will prevent market liquidity the regulator should consider if the potential penalty to the DSO can be socialised to encourage less onerous contractual terms.
Framework service agreements allow for multiple tenders which can be carried out at multiple time horizons including closer to real time.	DSOs should consider moving to framework agreements for DSO flexibility services which allow for multiple tenders to be carried and contracts to be quickly implemented.

Key Learnings	Recommendations
Contractual terms are not appropriate for domestic aggregators who will have limited scope of control over their customers.	Contractual terms need to be appropriate for all provider types including domestic aggregators to encourage market liquidity.
The FSA may need to be significantly revised to make flexibility services accessible to a wide range of providers and business models.	Engage with ENA Open Networks Project to determine the modifications required to their common FSA.

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

As with TP1 and TP2, non-traditional market participants have little time or resources to understand flexibility services and flexibility markets. A new market participant in TP3 had sufficient information to participate in auctions and choose the appropriate service for their DER type (HVAC) from their involvement in LEO and TRANSITION; however, they did not know how to forecast the flexibility available or optimise DER operation to maximise the benefits of participation. To help participants become flex ready LCH developed a six-step framework to address this; see Figure 2 below.

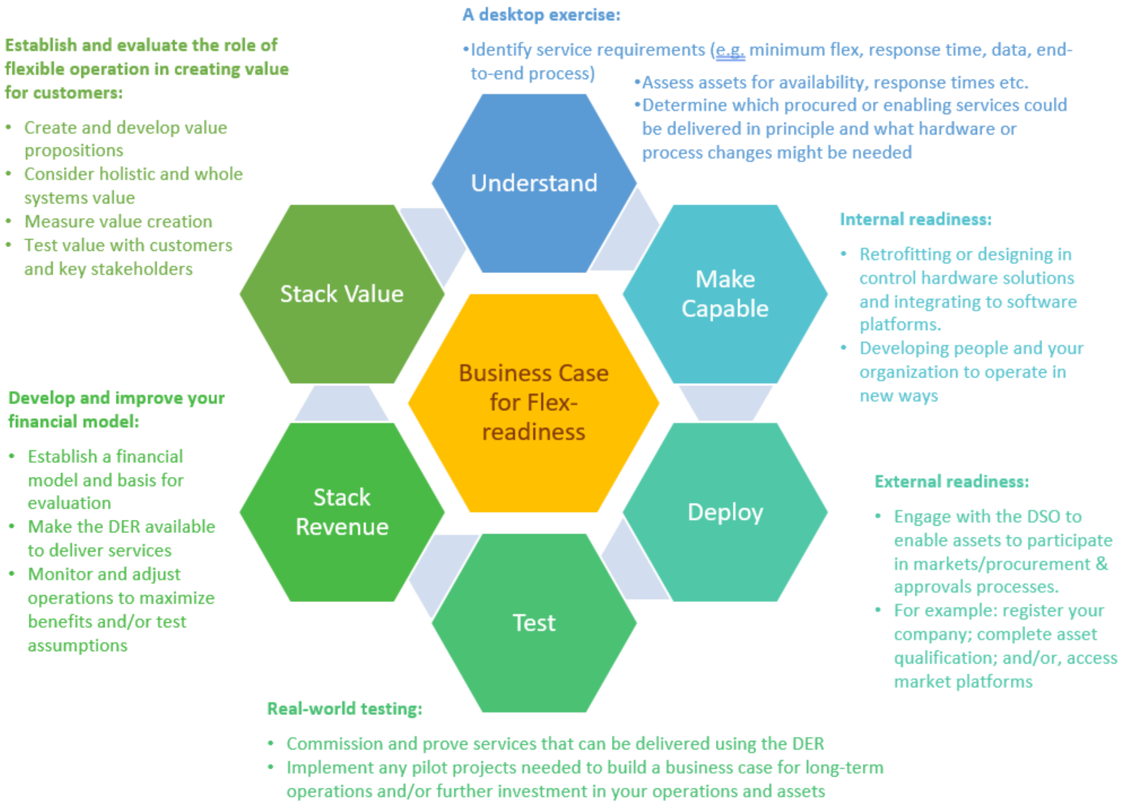


Figure 2: Flex-readiness Framework as Developed by LCH

This diagram shows the large number of steps and wide range of knowledge required to enable flexibility. This was highlighted during the commercial learnings workshop[9] when some market participants stated they would not be able to participate in flexibility services in BaU without third party support, e.g., an aggregator, due to the effort and costs attributed to participation.

2.4.1 Lessons from Aggregator onboarding during TP3

During TP3 one aggregator took part in DSO-Procured Services using domestic DERs to deliver flexibility. This presented several challenges to the aggregator that did not apply to other market participants and to SSEN. The challenges and mitigation measures are summarised below.

- **GDPR:** This prevents aggregators sharing the full postcode for DERs in their portfolio as required so the DSO can accurately identify and model DERs on their network. SSEN provided a mapping of postcodes to GSPs and BSPs so the aggregator could allocate DERs.
- **Aggregation Level:** Without accurate postcode data for DERs, the DSO cannot aggregate portfolios at lower voltage levels and must aggregate DERs at Primary or BSP which may limit the ability of domestic DERs to alleviate constraints in BaU.

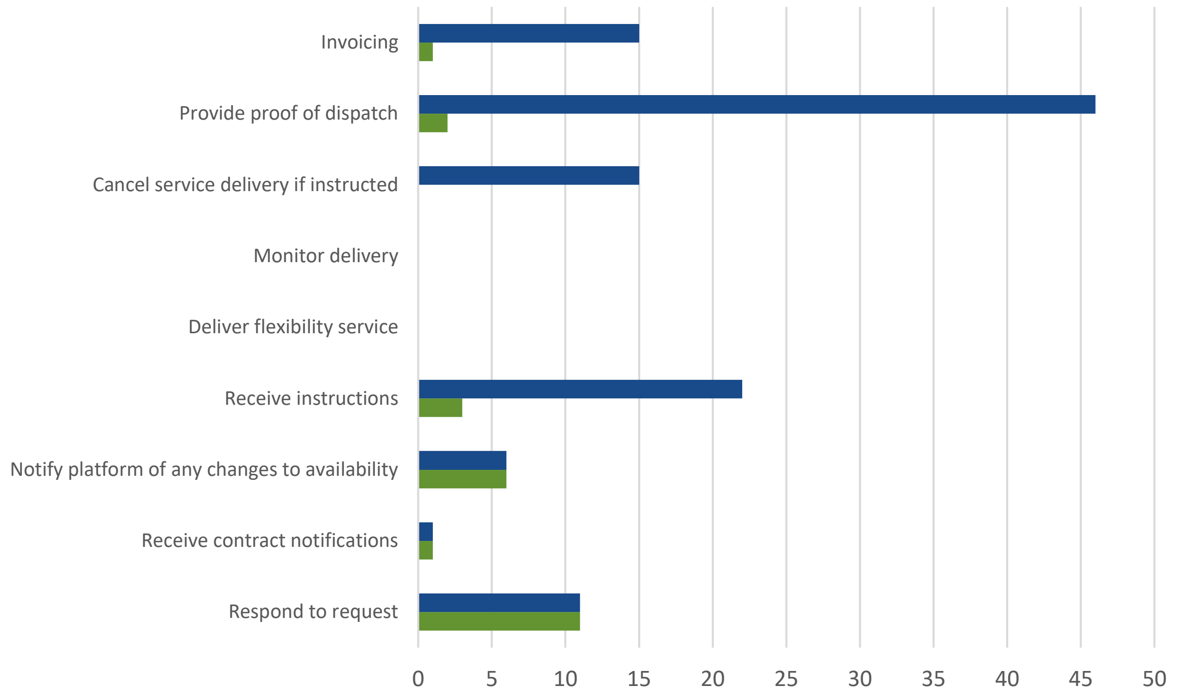
Table 7 - Learnings and Recommendations from developing markets for Non-Traditional DERs and Non-Traditional Business Models

Key Learnings	Recommendations
GDPR requirements increase aggregator and DSO workload to register DERs, requiring additional resource time.	Consider the information needed to identify the physical locations of DERs and explore the best process for implementing this.
The DSO needs to accurately visualise the location of DERs, especially as the ED2 plan identifies a large increase in domestic DERs.	Consider the best solution to maximise the connectivity information.
As the number of LV DERs increase, so will the effort required by the DSO to register them.	Consider the future role and responsibilities of aggregators and how they can help to avoid delays.

2.5 DER Enable and Control (PPS2.0)

The People's Power Station 2.0 (PPS2.0) is Low Carbon Hub's cloud-based platform that provides control and metering of connected DERs and enables participation in flexibility services. During TP3, the PPS 2.0 was used to schedule and dispatch LCHs rooftop PV portfolio and other individual DERs. The PPS2.0 platform was developed during the LEO project and the costs of maintaining the capability was too high to continue using the platform after LEO ended. This business case could be improved with increased automation, although that would require investment. The time reduction for each step required to deliver a flexibility service from responding to an auction request, dispatching the service, and invoicing for the delivery is summarised in Figure 3. If implemented, the analysis suggests these improvements could reduce the process time by ~92 mins and more as the number of flexibility events increases.

During TP3, LCH aggregated flexibility at BSPs and primaries; developing this capability could enable aggregation for ESO services. However, the relatively low revenue paid for the delivery of DSO services (see commercial learnings workshop[9]) means LCH may use a commercial aggregator to participate in such services, depending on their future business model and the allocation of risk and reward.



	Respond to request	Receive contract notifications	Notify platform of any changes to availability	Receive instructions	Deliver flexibility service	Monitor delivery	Cancel service delivery if instructed	Provide proof of dispatch	Invoicing
Current Automation	11	1	6	22	0	0	15	46	15
Increased Automation	11	1	6	3	0	0	0	2	1

Figure 3: Potential time savings from automation

Table 8 - Learnings and Recommendations from developing PPS2.0

Key Learnings	Recommendations
The income from delivering flexibility services with a low level of flexibility is insufficient to support a bespoke tailored aggregation platform	Standardisation of all aspects of flexibility (contracts, process, platform) will help to reduce costs of providing flexibility, but a third-party providing market access may be the best solution
APIs can reduce the time and cost of market participation and increase attractiveness, particularly when there is a high level of process automation for the market participant.	APIs should continue to be developed to lessen the burden on market participants, although the DSO should be mindful that of the level of process automation of the market participation.

3 Market and Technical Risk for Flexibility Provision

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

Continuing work done during Trial Period 2[Error! Bookmark not defined.], market indices were used during TP3 t o monitor and assess the function of the market and compare it to other Trial Periods. During TP3, primary level auctions were introduced at two BSPs, and relevant market indices were used to understand the implications of the inclusion of this type of auction on market function. Additionally, some more detailed work was carried out on reliability indices and how these can be used to ensure the level of procurement is correct by the DSO. The different market indices used here are described below.

Table 9: 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[12]. • 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.

3.1.1 Competition Index

Figure 4 shows the average competition index at each BSP for each week during TP3. This shows that there were only two BSPs at which the competition index dropped below 10,000 (absolute monopoly), however there was a significantly increased level of competition during the last two weeks of the trials, with the competition index dropping below 5120 in the last week at BSP B. This is broadly comparable to competition indices observed in Trial Period 2.

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

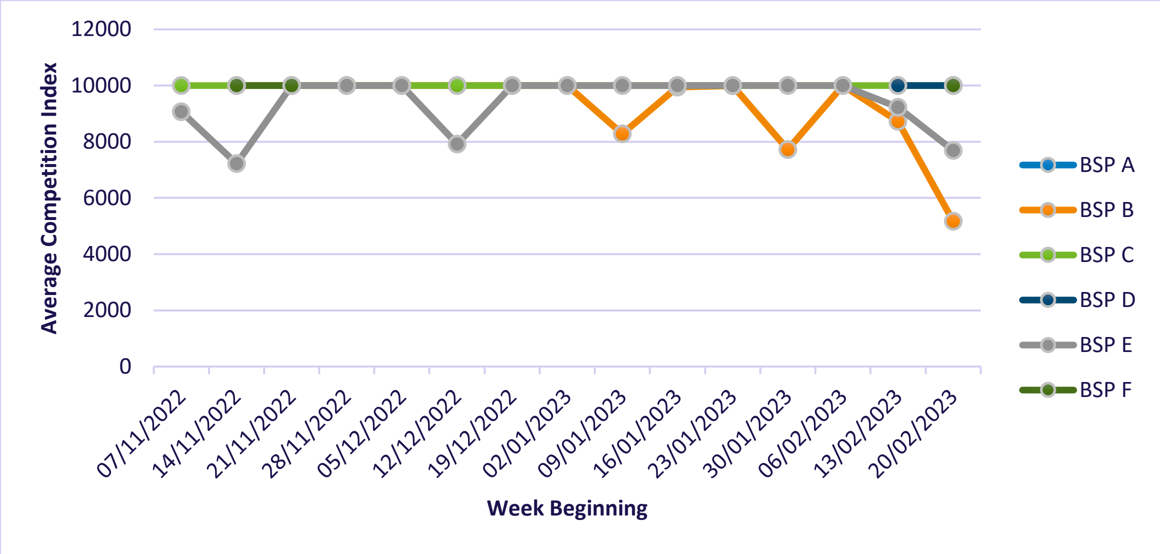


Figure 4: Average weekly competition index for each BSP during Trial Period 3 across all auction types and services.

Figure 5 shows how the competition index differed between auctions held at BSP level and at primary level. In general, the competition was much lower in primary level auctions, with only one primary level auction having a score of less than 10000, and only very marginally so. Auctions at BSP level incur a higher degree of competition.

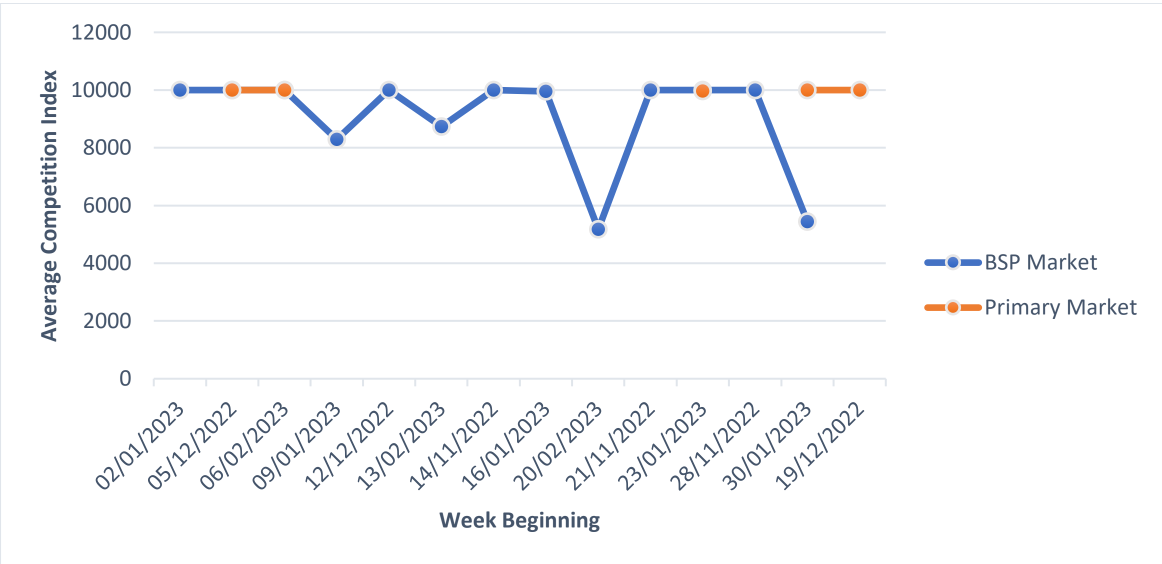


Figure 5: Weekly average competition index at BSP B for auctions at primary market and at BSP market.

For the SPM service, competition was generally increased as compared with Trial Period 2 (see Figure 6). On the other hand, SEPM, which had a higher degree of competition than SPM during TP2, was completely non-competitive in TP3, with all auctions having a score of 10,000. This is likely due to the fact that TP2 took place towards the end of summer, whereas TP3 took place in winter, which meant solar farms offering SEPM services had reduced opportunities for participation in TP3.

Figure 6: Weekly average competition index at each BSP for SPM service only

3.1.2 Liquidity Index

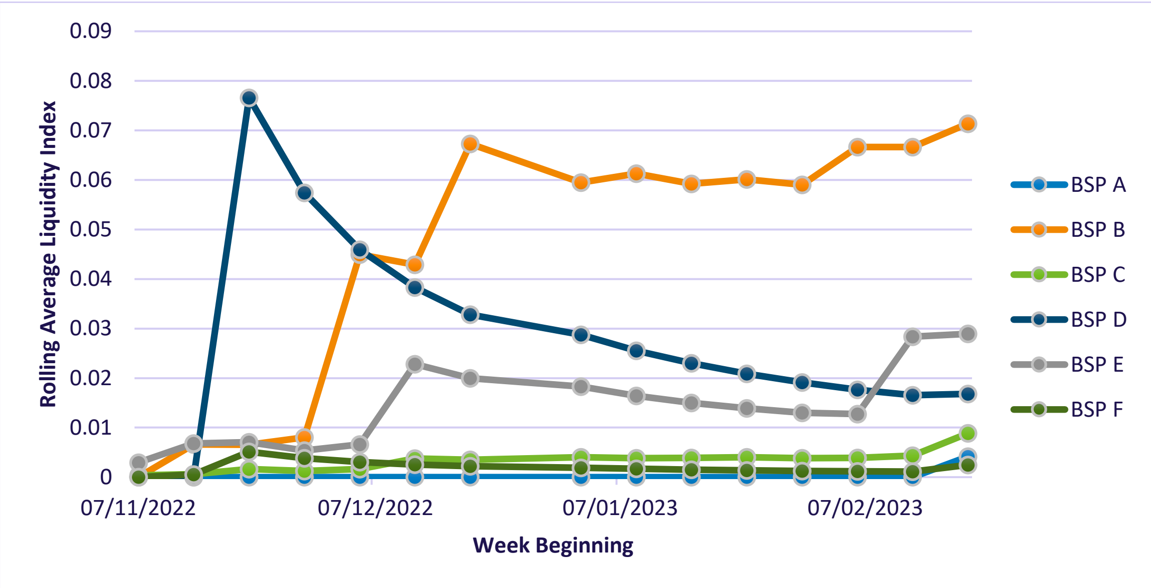


Figure 7: Average liquidity index over time at each BSP for all service types and auction types.

Figure 7 shows a moving average of the liquidity index over time across TP3 at each BSP. It is interesting to note that the liquidity index is typically much lower in TP3 than it was in TP2, despite the competition index being roughly the same, which means that although the participation levels are roughly the same, the volume of flexibility being procured is much lower. This can be understood by the fact that in TP3 some providers were offering very low volumes of flexibility in auctions. The average liquidity index is consistently below 0.1 at all BSPs, indicating that less than 10% of the requested flexibility was procured.

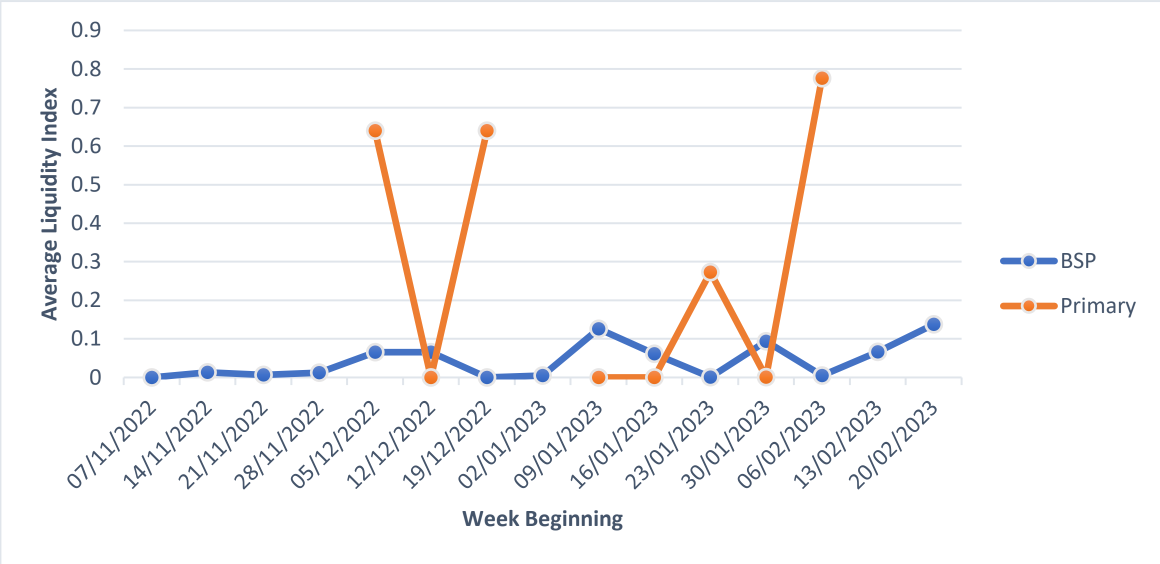


Figure 8: Weekly average liquidity index at BSP B for BSP market and Primary market auctions

Figure 8 shows the difference in liquidity between BSP market auctions and Primary market auctions at the same BSP. The liquidity at primary market is typically much higher when responses are received, however 50% of primary auctions received no responses. Liquidity is less likely to be zero at BSP, but the liquidity is much lower, typically around or below 0.1.

3.1.3 Reliability Index

Following on from the TP2 learnings and recommendations, TNEI conducted a detailed review and developed the reliability model during TP3. They applied a probabilistic approach that utilises a multinomial regression model. Discrete bands of reliability are defined, and the model outputs the probability of a DER type delivering within each band. To do this the model only considers delivery results. The model can be applied in two alternative ways. Firstly, it can be applied per DER type and season. Alternatively, a target date can be defined, and all data points weighed by their closeness to that date. Due to the limited data points available, the latter allows the inclusion of more data and thus provides a better model fit.

Table 10: Outputs of TNEI reliability model weighting DER types by proximity to target date.

Asset Type	No Delivery	Up to 10 %	10 to 20 %	20 to 30 %	30 to 40 %	40 to 50 %	50 to 60 %	60 to 70 %	70 to 80 %	80 to 90 %	90 to 100 %	Over 100 %	Overall Reliability
Battery	0.32	0.08	0.00	0.00	0.00	0.05	0.07	0.00	0.00	0.08	0.00	0.40	0.30
Demand Response	0.23	0.03	0.15	0.09	0.07	0.06	0.04	0.03	0.01	0.03	0.01	0.26	0.36
Hydro	0.05	0.89	0.01	0.00	0.00	0.01	0.01	0.00	0.00	0.01	0.00	0.02	0.06
Solar PV	0.86	0.00	0.13	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.01

The target day model was applied to the TP3 delivery data. To get a singular estimated reliability score for each asset type, the probability of each reliability class was multiplied by the mid-point of the class and then these values were summed together. The results can be found in the table above. The mean estimated reliability score, per asset type, for TP3 was 0.183. This suggests that, on average, assets in TP3 likely only delivered a small proportion of what was requested of them.

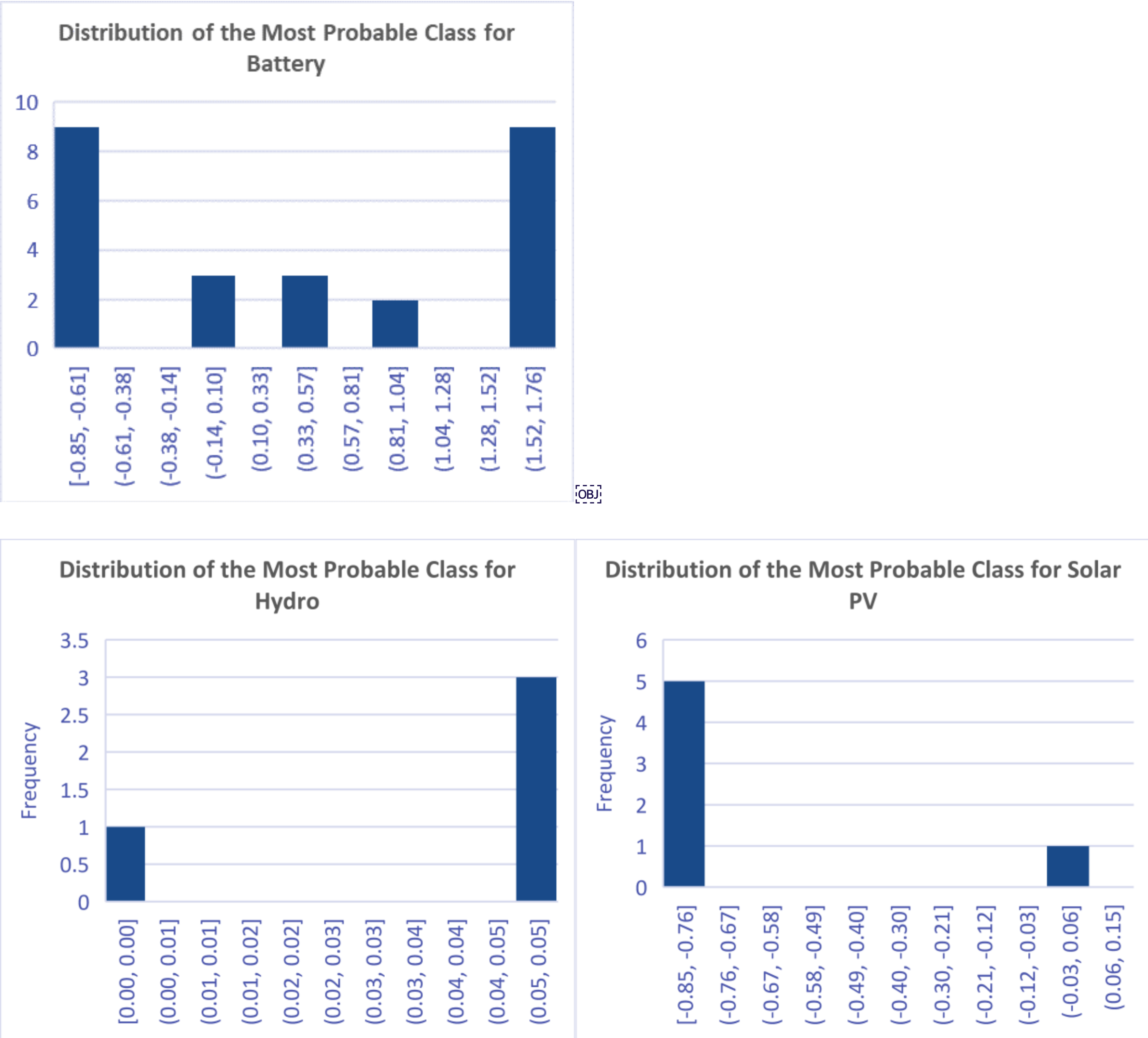


Figure 9: Distribution of the reliability per DER type for TP3

Figure 9 above show the distribution of the reliability per asset type for TP3. On more occasions, the battery DERs and the demand side response DERs have a positive reliability score. In TP3, most responses from battery DERs resided from one DER with whom we formed a close working relationship. These results highlight that the aggregated volumes of domesticated participation are more reliable than our individual working relationship with the battery, and thus the importance of participation from aggregators in flexibility markets.

The results are dependent on the accuracy of the baselining methodology. In TP3 we used the historical baseline methodology to calculate asset delivery. This methodology is not very accurate particularly for Solar PV DERs. The DSO was also aware that the hydro asset had some issues with delivery. One way to reduce the impact of asset reliability and the errors in the baseline methodologies is to use a capacity-based service.

Table 11 - Learnings and Recommendations from Market Analysis

Key Learnings	Recommendations
Liquidity at primary market is comparatively higher than at BSP level; however, liquidity is more likely to be zero. Further, auctions at BSP level incur a higher degree of competition.	Consider how these insights can support the development of the “menu” of flexibility products to be used in ED2.
The mean estimated reliability score, per asset type, was low. This suggests that, on average, assets in TP3 likely only delivered a small proportion of what was requested of them. However, this may be due to the baselining methods used.	More simple and accurate baseline model should be explored to those currently used in the Project Trials, in particular the Meter Before and Meter After approach. Alternatively, the DSO should consider whether baselining is a requirement for DSO services in BaU, as the value from such services may not merit validating services in this way.

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

The sections below provide a summary of the technical updates that occurred throughout TP3.

3.2.1 Updating and Amending Flexibility Capacity and Services on NMF

During TP3, asset owners and aggregators found that their DERs had varying flexibility delivery due to seasonal changes or trial plan arrangements, and therefore needed to amend the existing flexibility capacity. This process was carried out by the TRANSITION project team amending the DER parameters on NMF. If the requirement was to increase flexibility, then Opus needed to be advised to increase the settings from their model, and the TRANSITION team would amend it on NMF accordingly.

3.2.2 Removing DERs on NMF Platform

During TP3, an aggregator found that some assets were no longer available, and some assets needed to be aggregated into another portfolio. Therefore, those portfolios needed to be removed. The TRANSITION team instructed Opus to delete the portfolio from the system model, but this created another issue: the deleted portfolio had participated in the previous month's flexibility events, and all the records were also deleted. As a result, the project team was unable to conduct the settlement on NMF but instead had to conduct a manual calculation to ensure that the aggregator was paid correctly.

3.2.3 Baseline and Settlement

From November 2022 when TP3 began, the TRANSITION team started using NMF to conduct the full end-to-end process for conducting the baseline and settlement. Participants could respond to bids via NMF or Piclo and then receive a dispatch notification. Participants could also declare their assets' unavailability on NMF. By the 10th of the following month, IA uploaded their previous month's monitoring data to NMF for DSO to download. DSO then used the downloaded monitoring data and NMF stored trial events information to conduct a baseline study. During TP3, the TRANSITION project used the Python scripts developed by TNEI to conduct the baseline rather than the webpage, which accelerated the speed and saved manual effort when merging and checking the data and removing human error interfaces. Afterward, DSO uploaded the baseline result file back to NMF and triggered the settlement. Both IA and DSO could download the settlement report after this whole process.

However, there were a few issues within the settlement process during TP3. Firstly, the BST to GMT time zone change happened on 30th October 2022. This affected the eligible days period to conduct the historical baseline study, so monitoring data was required. Although both operated at local time, the NMF and the Baseline package required a different data format for input files. NMF needed the timestamp to be continuous with no duplications, while Baseline required a local time which, in this case, had 1-hour timestamp duplication. In this case, DSO had to instruct IA to upload their monitoring data to match NMF's request. After downloading the data from NMF, DSO had to manually duplicate 1 hour to match the required input format for the baseline tool. The same process was also needed for removing the 1-hour duplication in the baseline tool output file before uploading it back to NMF for settlement calculation.

Secondly, there were certain cases where DSO still needed to run some manual settlement calculations. One example was when IA raised a dispute over the settlement result, then DSO had to manually verify the calculation to ensure a fair amount was being rewarded. Another example was when a participant amended their monitoring data after DSO uploaded the baseline file and triggered the settlement. In this case, the settlement result on NMF could not be amended, and therefore DSO had to conduct a manual process and ignore the result on NMF.

3.2.4 Network Monitoring

During TP3, three additional LV monitors were installed to monitor the behaviour of participated assets. This brings the total number of installed LV monitors to 102, as shown in Figure 10.

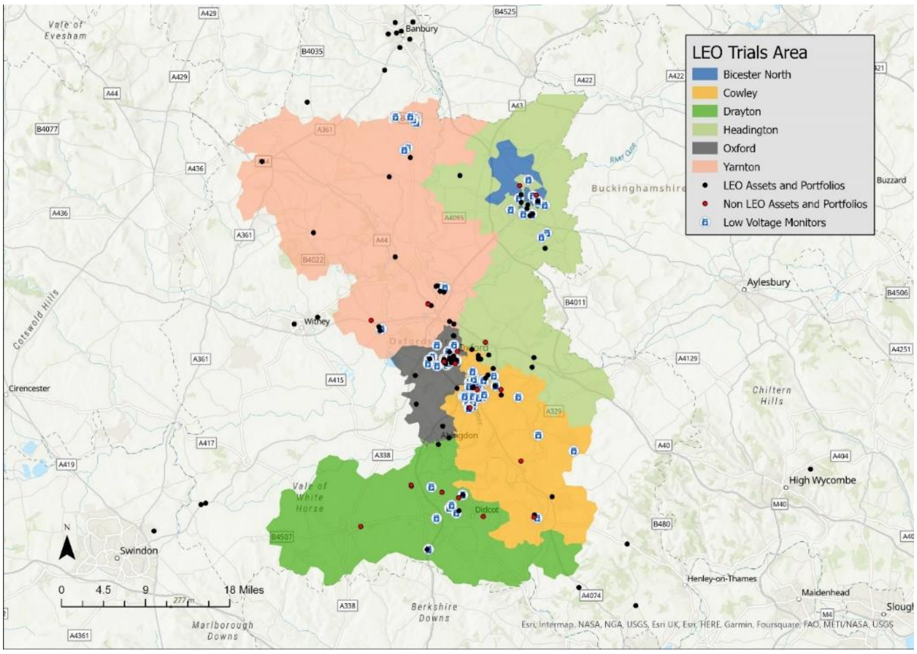


Figure 10: LEO trial areas, installed monitoring and DERs.

Two large contracts were placed during TP3. The first was a MOD bid for a 100kW SPM event on 14 February 2023, but the baseline study did not show any delivery. The second was a 500kW SEPM contract on 22 November 2022 from 11:00 to 12:00. Figure 11 compares the SSEN PI historian data with the monitoring data provided by the IA, and shows that they follow the same trend, verifying the accuracy of the customer monitoring data. The baseline result indicates full delivery, and the data for the SEPM event on 22 November 2022 shows a dramatic drop, which matches with the baseline result and helps with the SEPM event.

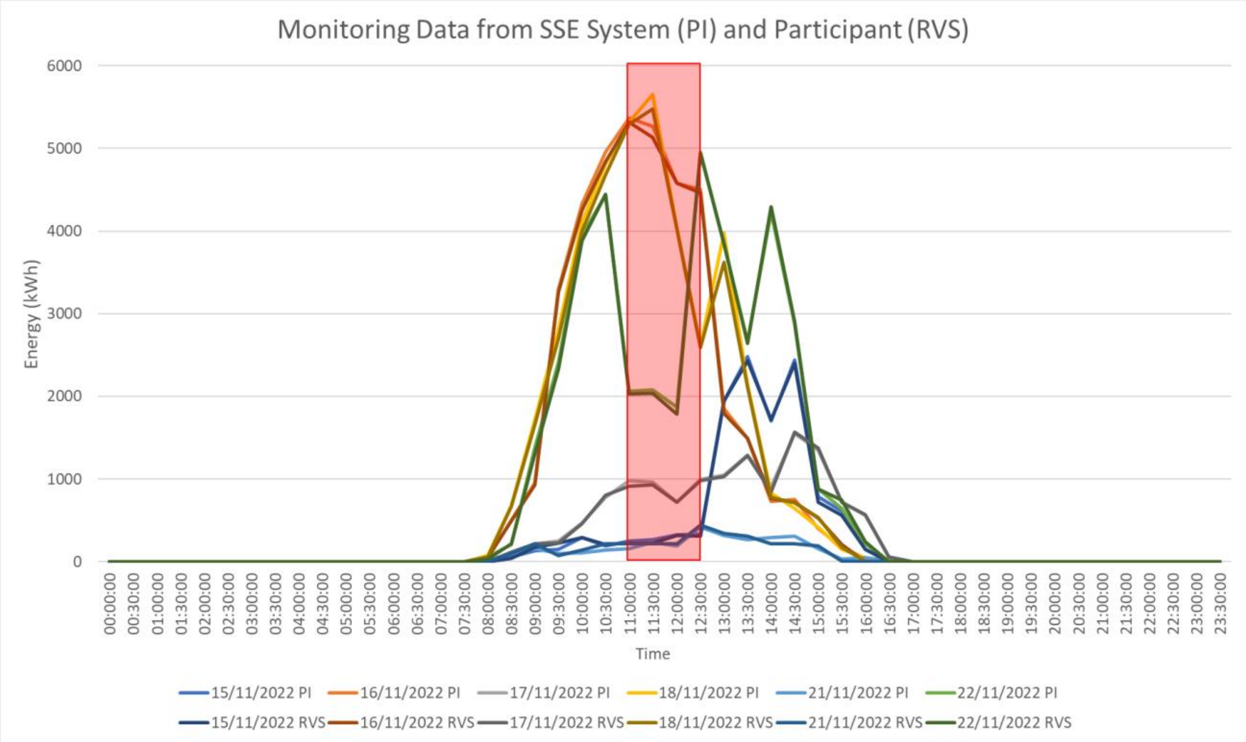


Figure 11: Comparison for an SEPM Event of data from SSEN system and participant

Table 12 - Learnings and Recommendations from Technical Start Up

Key Learnings	Recommendations
DSO-Enabled services were found to be not cost-effective under the TRANSITION trials and require high technical involvement, which can discourage participant involvement.	DSO-Enabled services need a stronger market signal to show demand for these services with better incentives and easier participation.
Removing DERs from the existing model can result in the deletion of participation records, making it impossible to calculate settlement automatically.	DSOs need to consider the full end-to-end process and identify potential chain reactions before taking any actions. For example, amending the existing asset/portfolio in NMF should not create barriers for settlement.
There are situations where different platforms require input files in different formats, such as during the UK time zone change.	Need to coordinate with platform providers to ensure a consistent format is agreed upon among all parties. This situation also applies when using APIs to collect data.

4 Unintended Consequences

4.1 Disputes

Throughout TP3, participants were encouraged to raise settlement disputes where issues were identified with the baselining and settlement process, in order to allow SSEN to test the dispute process and to record learnings on issues and areas for improvement in the baselining and settlement processes. As a result, there were two settlement disputes during TP3.

4.1.1 Dispute Process

Both disputes raised during TP3 arose because participants did not feel that the baselining process had accurately estimated the flexibility delivered on certain dates, and as a result the participants settlement payments were lower than expected. In both instances, calls were arranged between members of the SSEN team and the participants in question to go over the issues and discuss the settlement calculation. Following these calls, participants were encouraged to raise disputes by submitting an FSA term sheet dispute form. The disputes were then settled by SSEN providing a formal response to these forms (in both cases the full settlement value was offered by SSEN to resolve the disputes).

4.1.2 Learnings

The existing dispute resolution process was used effectively to record and settle disputes in the baselining and settlement process in both cases (although note that at the time of writing, one dispute is still pending formal closure). Feedback from participants indicated that this process was satisfactory, and in particular they appreciated an opportunity to discuss the issue with the SSEN team on a call during the process. The dispute process therefore seems to be effective at resolving issues and maintaining goodwill between SSEN and participants.

The key issue driving both disputes was a lack of clarity on the format for measurement data required, with one provider having uploaded data in the wrong time-zone format (UTC instead of local time) and another provider having uploaded data with timestamps indicating the start of the measurement period instead of the end of the measurement period (as required by the NMF). One important learning is therefore that to minimise potential for future disputes, care should be taken to make sure the format of the data requirement is understood by all participants, and opportunities for errors in the data upload should be minimised going forward into BaU.

In the case of the first dispute, a participant also felt that their baseline results had been negatively affected by the inclusion of dates on which assets had participated in non-DSO demand reduction services (such as NG DFS) in the baseline calculation. Another learning from this process is therefore that it would be useful to develop a process which makes it easy for participants to exclude certain dates from their calculations to avoid future disputes along similar lines.

Table 13 - Learnings and Recommendations from Disputes

Key Learnings	Recommendations
The dispute resolution process was used to effectively resolve issues around baselining and settlement, and participant feedback found this process to be satisfactory.	Share process with our BaU colleagues.
Disputes were raised due to errors in the format of measurement data uploaded by participants.	Ensure the format of data required is made clear to participants and refine the documentation and data cleansing tool to prevent similar disputes occurring in future.
Participants felt that inclusion of dates on which they participated in non-DSO services affected their settlement negatively.	Provide a mechanism for participants to exclude certain dates from their baseline calculations where necessary due to participation in other services.

4.2 Gaming Opportunities

4.2.1 Gaming Opportunity

It was recognised within Project LEO trials that there was an opportunity for gaming due to the nature of the scheduled events. This was specifically relevant for week ahead auctions because the service window of Week Ahead contracts would cover a whole week (five service days), whereas scheduled events would only take place on one day. As Week Ahead Auctions were shared with participants, the specific day and time at which assets would be dispatched was also shared. This meant that participants could auction for the week and only provide an unavailability notice for their assets on the day and time of the scheduled event, because they knew they would not be requested to dispatch on the other days. This allowed assets to gain availability payments for the other service days in the week even if they did not have the ability to deliver when requested. In a Business-as-Usual context, this kind of gaming could negatively impact the DSOs ability to procure the required amount of flexibility to meet system needs, because it means that the DSO might not have full information about which of the contracted assets are available for dispatch at a given time.

4.2.2 Reasoning for Scheduled Events

Throughout the trials, alignment between the capability of the technology and the market was required. Due to the system capability within TP3, forecasted events could not be achieved which meant only scheduled auctions could be held. The market for flexible energy is also a relatively new concept and to ensure participants had the best chance of participating and delivering their flexibility, sharing event times in advance gave participants the opportunity to prepare their assets ahead of time. Given the nature of market and trials, there were manual steps required from participants to ensure their bid in flexibility could be provided e.g., manually reducing their demand. It was agreed for the trials and to ensure the technology and market availability was suitable for the trials, event times would be shared.

4.2.3 Learnings

The leaning taken from TP3 are sharing event times too far in advance allows gaming opportunities, specifically for Week Ahead auctions.

Moving beyond TP3, the recommendation would be to not share event times and only to stick to the agreed notification periods of each service. See below:

- DCM – 30 minutes
- SCM – 4 hours
- SEPM – 12 hours
- SPM – 12 hours

It is recognised that sticking to these notification times may reduce participation in auctions, specifically for the DCM and SCM auctions as there is less time to prepare for the event. It does, however, dramatically reduces the potential for gaming opportunities.

Another learning would be to improve the IT system's capability to provide forecasted events using real-time data. This would reduce the ability to schedule the events and would provide a more realistic scenario when adopted in an operational environment.

A further learning is the need for automation of processes and assets and/or the use of aggregators. Further developing the technical capabilities of the participating assets would reduce the need to prepare for asset dispatch and manual intervention, meaning participation in all auctions would increase regardless of the notification period.

Table 14.2 - Learnings and Recommendation from Gaming Opportunities

Key Learnings	Recommendations
Sharing event times in advance enables gaming opportunities, specifically for Week Ahead Auctions	Do not share event times out with the agreed notification periods. This ensures any assets being used in auctions can dispatch and stops unavailability notices being planned for event times for those assets that cannot.
The IT systems used within the trials could not use forecasted data meaning only scheduled events could be held. This enabled planned event times to be shared in advance.	Improving IT systems to create Forecasted events would decrease the ability to plan event times and provide a more realistic scenario for an operational environment
Manual intervention was required to ensure participating assets could dispatch at the time required. This mean sharing event times in advance was a	Further work to automate systems for local assets would reduce the time to prepare for asset dispatch.

Key Learnings	Recommendations
requirement for participants to ensure they could participate in auctions.	

5 Commercial – DSO

5.1 DSO-Procured Services Benefit

Flexibility services such as SPM can be procured by the DSO to defer the need for network reinforcement as peak demand on the system increases. Flexibility services such as SCM / DCM can also be used to minimise the effects to customers on outages. In this analysis, the costs of flexibility procured to mitigate peak demand (SPM) is compared against the cost of network reinforcement to determine the optimal duration of flex and the maximum benefit. A similar analysis could be performed for other flexibility services (e.g., SCM and DCM), but instead comparing the cost of flexibility against the cost of customer minutes lost, customer interruptions, and Mobile Diesel Generator (MDG) as back-up. However, this analysis is outside the scope of this report.

This cost benefit analysis is carried out using the ENA's Common Evaluation Methodology (CEM) tool, developed by the ENA Open Networks project. At each BSP, available data from TP3 was used to calculate the cumulative Net Present Value (NPV) of SPM flexibility services under four scenarios. The maximum value of the cumulative NPV gives the total value that can be achieved by utilising flexibility services for the optimal duration as opposed to immediate network upgrades. The time at which this maximum cumulative NPV is obtained indicates the optimal length of time flexibility should be used for. NPV is a metric showing the value of utilising flexibility at a given time.

5.2 Data Inputs

The CEM tool requires several data inputs to perform the cost benefit analysis on flexibility. The first of these are the initial price assumptions for flexibility. For the TP3 analysis these are calculated as the weighted averages of availability and utilisation prices for accepted SPM contracts during TP3. Only the SPM service is included in the analysis because SPM is the only service which alleviates peak load constraints and therefore the only service that assists with deferring network upgrades. The average prices used are shown in Table 10.

Table 15 Weighted averages of availability and utilisation prices for SPM contracts during TP3.

BSP	Availability Price (£/MW/h)	Utilisation Price (£/MWh)
BSP A	60	0
BSP B	27.26	327.40
BSP C	47.78	138.89
BSP D	60	0
BSP E	20.66	463.93
BSP F	60	0

Another required data input for the CEM tool is the peak network load projections. These were calculated for the period 2021-2030 using data from the 2021 Distribution Future Energy Scenarios (DFES) based on their four scenarios: Leading the Way (LW), Consumer Transformation (CT), System Transformation (ST), and Steady Progression (SP). To artificially constrain the network (since TRANSITION uses parts of the network which are not currently facing constraints), a current network capacity close to the current peak load estimates was chosen (for example in BSP E the current load estimate averaged across the four scenarios is 84.2 MVA so an initial capacity of 85 MVA was selected). The CEM tool then uses these load projections and the capacity to calculate the projected exceedance of the network capacity per year for each scenario. From this the amount of flexibility needed to defer network upgrades is estimated.

In TP2, utilisation hours and days for flexibility services were assumed, however in TP3 a methodology was developed to calculate the expected utilisation hours and days based on the DFES projections, which should give a more accurate estimation of the flexibility needs for the cost benefit analysis.

Finally, the CEM tool requires baseline reinforcement costs to compare the costs of flexibility against. For this, the same upgrade costs were used as for the TP2 CEM analysis which is based on the cost of Transformer and 33kV cable replacement.

5.3 Cost Benefit Analysis

The cost benefit analysis was performed for only the three BSPs at which market participation was highest for SPM: BSPs B, C, and E.

5.3.1 BSP B

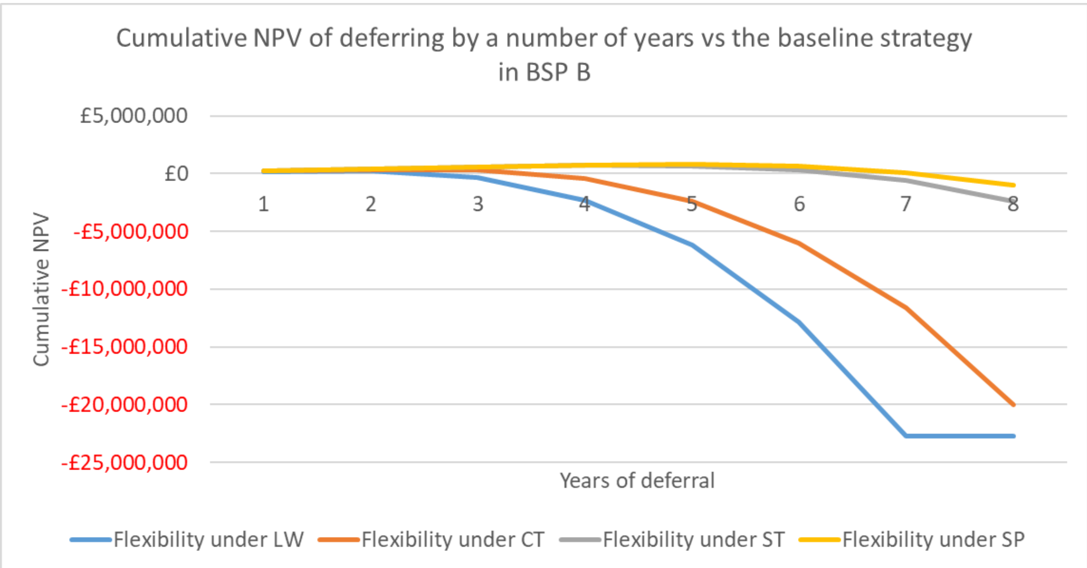


Figure 12 Cumulative NPV of flexibility against reinforcement deferral at BSP B.

Table 16 Optimal reinforcement deferral duration by NPV and scenario at BSP B.

DFES Scenario	Year of Maximum Cumulative NPV at BSP B	Value of Maximum Cumulative NPV at BSP B
Leading the Way	2	£208,260
Consumer Transformation	2	£348,764
System Transformation	4	£702,412
Steady Progression	5	£792,856

5.3.2 BSP C

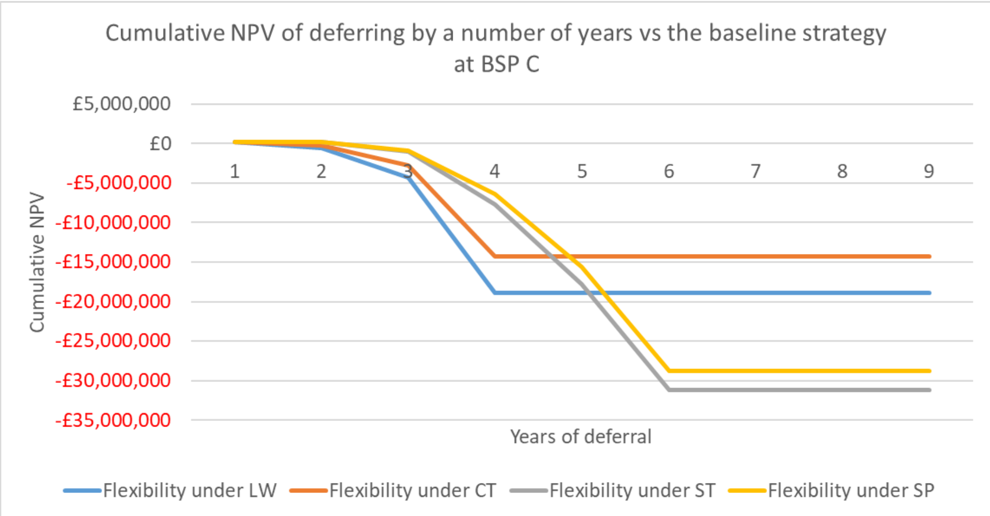


Figure 13 Cumulative NPV for flexibility against reinforcement deferment at BSP C.

Table 17 Optimal reinforcement deferral duration by NPV and scenario at BSP C.

DFES Scenario	Year of Maximum Cumulative NPV at BSP C	Value of Maximum Cumulative NPV at BSP C
Leading the Way	1	£187,056
Consumer Transformation	1	£193,640
System Transformation	1	£193,640
Steady Progression	1	£193,640

5.3.3 BSP E

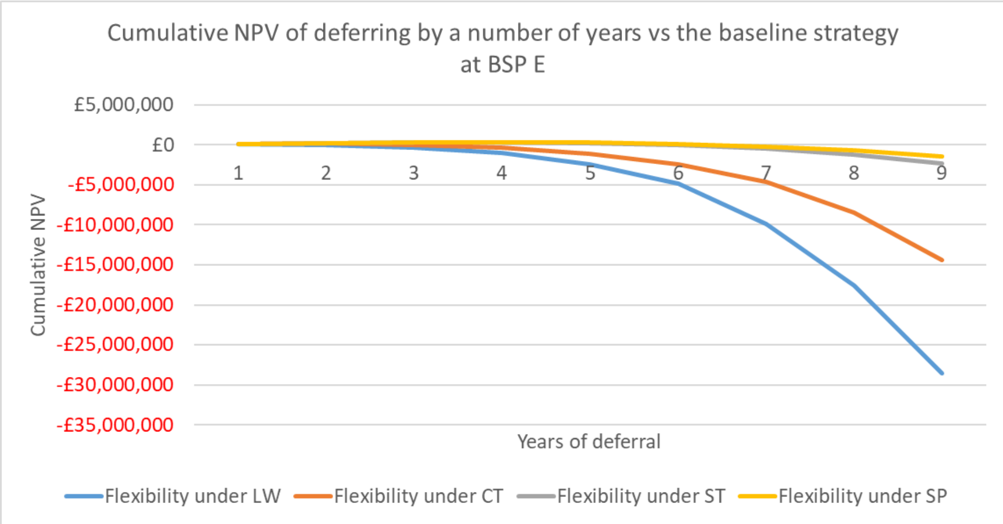


Figure 14 Cumulative NPV for flexibility against reinforcement deferment at BSP E.

Table 18 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	£84,836
Consumer Transformation	2	£134,497
System Transformation	4	£319,051
Steady Progression	4	£352,150

5.3.4 Overall Results

The CEM tool also uses a weighted average method to determine the optimal years of network reinforcement deferral across all four strategies (assuming a percentage probability of each DFES scenario occurring). This optimal deferral value is given for each of the three BSPs in Table 19 Weighted average optimal deferral duration, maximum expected benefit, intrinsic benefit and uncertainty benefit for each of the three analysed BSPs. This table also shows the maximum expected benefit of the weighted average flexibility strategy across all four scenarios. The intrinsic benefit is the maximum expected benefit of the best-case scenario (here Leading the Way is used), and the uncertainty benefit is the intrinsic benefit subtracted from the weighted average maximum benefit. When determining whether deploying flexibility to avoid reinforcement a key factor should be to assess the optionality benefits by using the intrinsic benefit based on the most likely demand scenario and optimal contract length against the potential benefit across all demand scenarios. This additional uncertainty benefit can be factored in if there is not clear decision based on the benefit of the most likely demand scenario and can support an increase in the ceiling price to incentivise flexibility providers.

Table 19 Weighted average optimal deferral duration, maximum expected benefit, intrinsic benefit and uncertainty benefit for each of the three analysed BSPs.

BSP	Optimal years of deferral	Maximum Expected Benefit by Strategy	Intrinsic Benefit Based on Leading the Way	Uncertainty Benefit
BSP B	2	£410,459	£208,260	£202,198
BSP C	1	£153,595	£187,056	-£33,461
BSP E	1	£178,107	£84,836	£93,271

The above results show that the optimal length for flexibility services and the value offered by implementing flexibility services varies a lot between different BSPs and between different scenarios. At BSP B, the weighted average optimal years of deferral is two years. Some scenarios analysed for BSP B suggest that flexibility could even be beneficial for longer. The optimal contract length at BSP B is therefore two years, at which point the DSO can reassess the need for flexibility. and all scenarios analysed suggest a minimum of two years of flexibility would be beneficial. Utilising flexibility services to defer network upgrades at BSP B could offer benefits to the DSO to the value of ~£400,000 according to this analysis.

BSPs C and E have optimal deferral timeframes of only one year, and the maximum expected benefit resulting from flexibility deployment is also lower than at BSP B. At BSP C, the optimal duration of flexibility services is one year across all scenarios, so it is likely that this BSP would require network upgrades after one year. However, at BSP E, some scenarios suggest that flexibility services could be valuable for longer, so the DSO should reassess the benefits of flexibility after one year.

The significant variation in these results between different scenarios highlight the need for frequent review and re-analysis of the data to make the best-informed decisions, and also demonstrate the need for the most up-to-date and accurate data inputs possible for the CEM tool. In TP3, using improved data inputs on utilisation hours and days, and updated flexibility costs, significantly changed the results of the cost benefit analysis as compared with TP2. One of the key recommendations should therefore be that for future analysis, the quality and relevance of the data used should be ensured.

Table 20 - Learnings and Recommendations from Commercial DSO

Key Learnings	Recommendations
Using the CEM tool to provide recommendations for flexibility procurement highlights the need for as up-to-date and relevant data inputs as possible.	Ensure processes are in place to provide up-to-date data when needed to perform analysis.
The value of flexibility and the optimal duration of flexibility services are very responsive to the demand scenario that is used.	The CEM tool should be used to reassess flexibility regularly as more data on demand growth becomes available.

6 Commercial – DER – Introduction

A variety of market participants took part in TP3, each with different business models and drivers. TP3 included a variety of DER types, each with different operating characteristics and appropriate services.

6.1 Comparing and Contrasting Different DER Types

Baringa and SSEN held a two-part workshop series in early 2023 to compile commercial learnings from TP1, TP2 and TP3 and this is summarised in a separate report[9]. Additional work has been undertaken to; quantify the viability of Sandford Hydro participating in DSO-Enabled services, explore the benefits of automation and scaling portfolios, and record the non-financial benefits of participating in the trials.

6.1.1 Learnings from Sandford Hydro

The availability of Sandford Hydro limited the opportunity for it to participate in TP3. Analysis of the availability of flexibility shows there was limited days this DER could have delivered DSO-Procured services (due to control system upgrade and insufficient water), see Figure 15. Flexibility is dependent on rainfall and can be unpredictable and intermittent which makes this DER more suited to Exceeding MEC and Exceeding MIC services or used in a SCES.

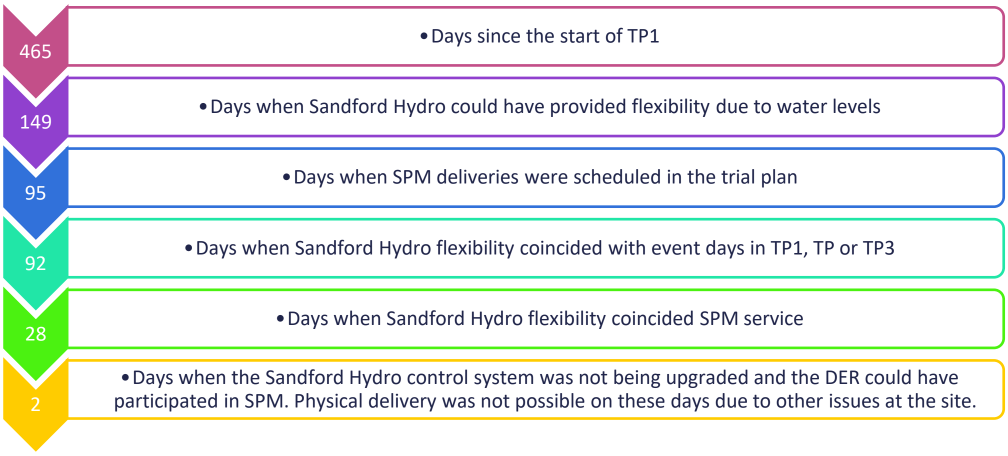


Figure 15: Historical analysis conducted on the availability of Sandford Hydro

6.1.2 Costs and Benefits of Trial Participation

The costs of participating in DSO-Procured services is high compared to the financial rewards and market participants explored automation and scaling their portfolios to improve the business case.

Automation

- One installed smart plugs that enable scheduling or remote control of some DERs. This improved matters if the service window was outside working hours but did not reduce the overall time to participate. Their largest DERs (HVAC) requires manual switching with automation estimated to be £100 per DER plus software development costs.
- An aggregator utilises smart plugs to dispatch their aggregated portfolio of residential appliances and can schedule dispatch automatically; however, they are postponing full E2E automation until industry requirements are known.

- LCH have integrated several of their DERs with the PPS2.0 to automate scheduling and dispatch, see Section 2.5.

Scaling of Portfolios

LCH considered the benefit of aggregating their DERs in a portfolio compared to using them separately to provide DSO-Procured Services. They found that using a portfolio of aggregated DERs from a diverse number of sources:

- increasing the capacity, they can offer into an auction and reduced the risk of under-delivery.
- reduced the process steps applicable to a DER as they apply to the portfolio (Table 21).
- reduced the time to participate in an auction as the decision time for a portfolio is similar to an individual asset and is largely proportional to the number of DERs; the time saving could be significant as a portfolio grows.

Table 21: Steps required to participate in DSO-Procured Services per DER / portfolio[13]

	Register	Respond to Request	Receive Contract Notification	Notify of changes to availability	Receive Instruction	Deliver Flexibility	Monitor Delivery	Cancel (if required)	Proof of Dispatch	Invoice
Individual DER	■	■	■	■	■	■	■	■	■	■
Per DER in Portfolio						■	■	■	■	
PER Portfolio	■	■	■	■	■					■

Non-Financial Benefits of Trial Participation

As per TP1 and TP2, market participants highlighted the non-financial benefits were more important than the financial benefits from participation as illustrated in Figure 16.

[13] Each step would have to be repeated for every individual DER participating in a DSO-Procured service.

Market Partcipant
- Get paid more for generation volume during delivery period which increases revenue
- Justify grant funding which improves business case
- Explore and test new strategy and learn how to participate in flexibility market
- Increase electricity above export / import capacity
- Generate income from spare capacity

DSO
- Prevents constraints during peak periods, deferring or avoiding investment
- Shift demand to periods when it is needed
- Mitigate and manage faults, reducing CMLs and network issues
- Balance renewable generation with local demand, which reduces losses
- Use the network for efficiently

Local Community
- Increase jobs in the community; need people to manage the E2E process
- Local carbon emissions are reduced through generating and using renewable energy locally
- Increased revenue can be passes on to local communities / hosts
- Reduce energy bills
- Store surplus generation for self-consumption

Figure 16: Non-Technical Learnings from Trial Participation

Table 22 - Learnings and Recommendations on Comparing and Contrasting Different DER Types

Key Learnings	Recommendations
The unpredictable and intermittent nature of hydro generation may mean it is better suited to Exceeding MEC, Exceeding MIC or SCES.	Conduct further analysis to determine the best business case for this DER type.
Implementing a 'whole portfolio approach' and automation can improve the business case for participating in these flexibility services.	Consider standardising the E2E across different markets to lessen the burden and costs to market participants.
DSO-Procured and DSO-Enabled services can provide a range of non-financial benefits for the DSO, market participant and local community.	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.

6.2 Comparing and Contrasting Holistic Business Models

This section examines two case studies; the use of Behind the Meter (BTM) flexibility to deliver DSO-Procured services and benefit the local community and how solar PV can generate revenue from SEPM.

6.2.1 Case Study 1: Solar PV with Battery

LCH has access to two community based DERs located in the same area: a battery on a community centre and solar PV installed at a school. During the Project Trials, it was hoped these two DERs could be optimised so the battery stores generation from the solar PV when it is more than on-site demand and discharges the energy at a different time to increase the value of the generation by either (i) supplying the host site and / or (ii) exporting to deliver DSO-Procured services.

Preliminary analysis from TP3 has shown that LCH made a loss whilst using this model during TP3, as the low generation from Solar PV meant they had to import to prevent the battery from fully discharging. Further, there may be limited opportunities to supply the battery during the school term, as the Solar PV has been sized to efficiently meet the needs of the school.

During periods of high Solar PV generation and low demand (e.g., summer) it would be possible for LCH to generate revenue from SEPM when solar PV generation charges the battery. The stored energy can then be used to supply the community centre needs or participate in another service (e.g., DCM).

Although this was not possible during TP3, the implementation of this holistic business model has provided learnings on the allocation of revenue between the different DERs BTM and demand and generation. This means that LCH has three different settlement tools at present:

1. BTM settlement to allow LCH to bill the school.
2. NMF settlement which shows the charging and discharging power / energy for a single or group of batteries; and
3. NMF settlement which shows the power output of PV from inverter level all the way to groups of assets.

The challenges associated with the data required to bill and attribute carbon / revenue from multiple DERs BTM can be categorized into: availability (is the data needed being captured in some way), accessibility (can it be accessed) and reliability (how reliable is the data comms access and the data).

It was found that in many cases, even when the DER has metering installed, accessing the data was difficult. For example, the yearly cost to access 1-min resolution data via cloud interfaces is generally fixed for large portfolios, with prices ranging from £5,000 to £10,000. This presents a major challenge for the financial viability of active participation using a small number of assets.

6.2.2 Case Study 2: Ray Valley Solar

Ray Valley Solar (RVS) is a large community-owned ground mount solar park which successfully took part in the delivery of SEPM during TP2 and TP3. Analysis from both trial periods concluded that it was possible to generate an income from the delivery of SEPM, subject to caveats:

- **Recovery of enablement costs:** The DER needs to be involved in the delivery of multiple services as RVS experience as it would take ~200 SEPM events to recover enablement costs.
- **Reducing operation costs**: Integrating RVS into the PPS2.0 within a portfolio of DERs would enable the realisation of the full financial value of delivering flexibility. Again, the delivery of multiple services would improve the attractiveness of including the DER in PPS2.0.

Further, participant operation costs can, and need, to be reduced to realise the full financial value of delivering flexibility. RVS is scheduled to be integrated into People's Power Station 2.0 (see Section 2.5) which will automate the end-to-end process of delivering flexibility and reduce the operational costs to participate. Although the costs for developing the PPS2.0 and integrating their portfolio with this system are high, the reduction in operational costs will enhance the business case for delivering flexibility.

Table 23 - Learnings and Recommendations on Comparing and Contrasting Holistic Business Models

Key Learnings	Recommendations
There are significant challenges associated with the data required to bill and attribute carbon / revenue from multiple DERs BTM.	Consider what funding is required to help with the development of fit-for-purpose metering and / or a platform to enable data acquisition for small scale DERs / portfolios.
Innovation funding is required to help with the development of fit-for-purpose metering and / or a platform to enable data acquisition for small scale DERs / portfolios.	Consider the metering and / or a platform requirement to enable data acquisition for small scale DERs / portfolios.

Appendix A Auction Analysis

As shown in Figure 17 toFigure 20, the requested capacity was varied between auctions to replicate the variable nature of DSO needs; however, as the request capacity was kept significantly higher than the flexible capacity of the available DERs (to ensure each could participate in the auctions) the amount offered was always less than that requested amount and the price cap prevailed, see Figure 21 andFigure 23.

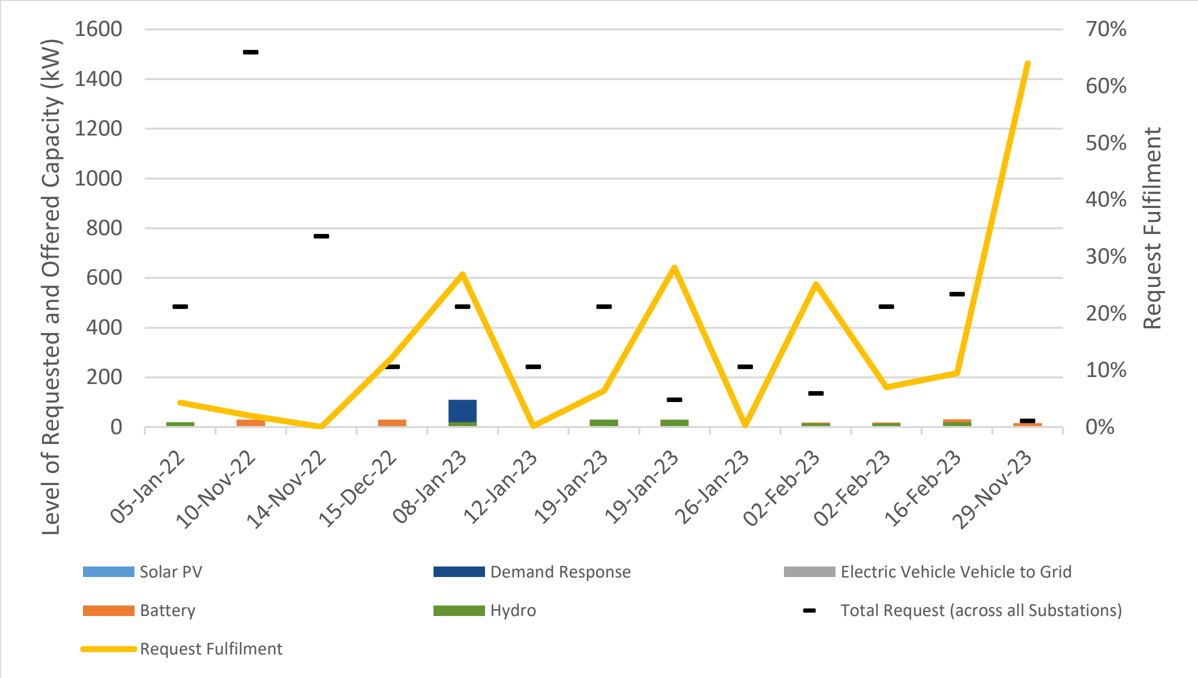


Figure 17: Response by DER type against requested capacity (with % of request fulfilment) for SPM.

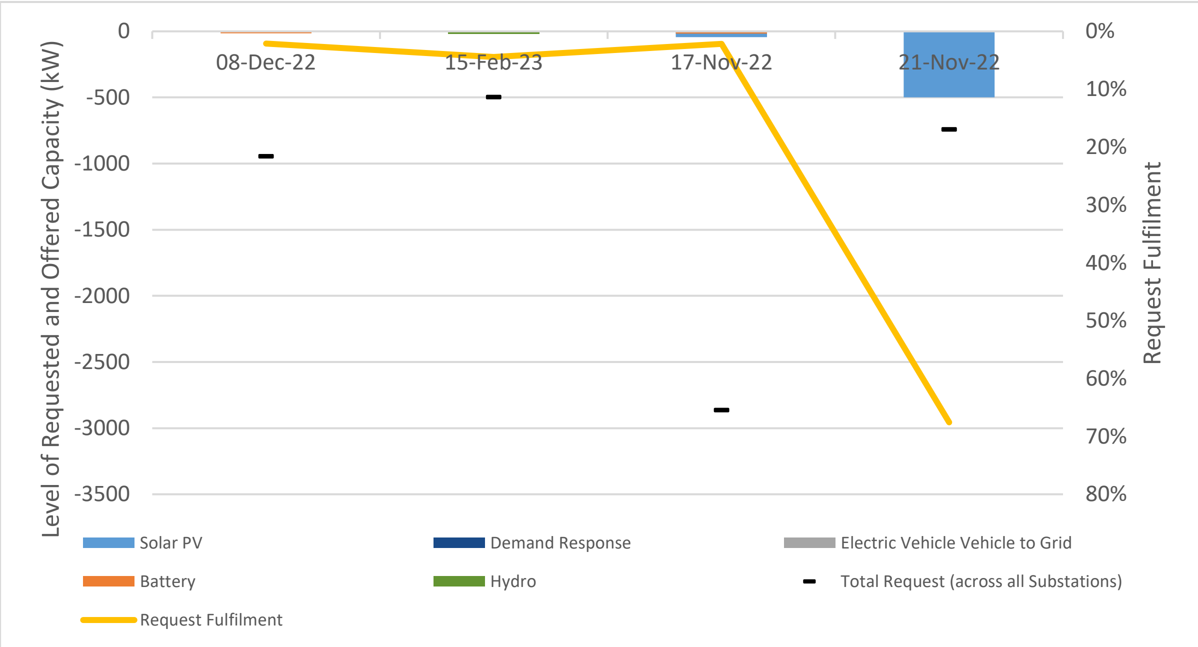


Figure 18: Response by DER type against requested capacity (with % of request fulfilment) for SEPM.

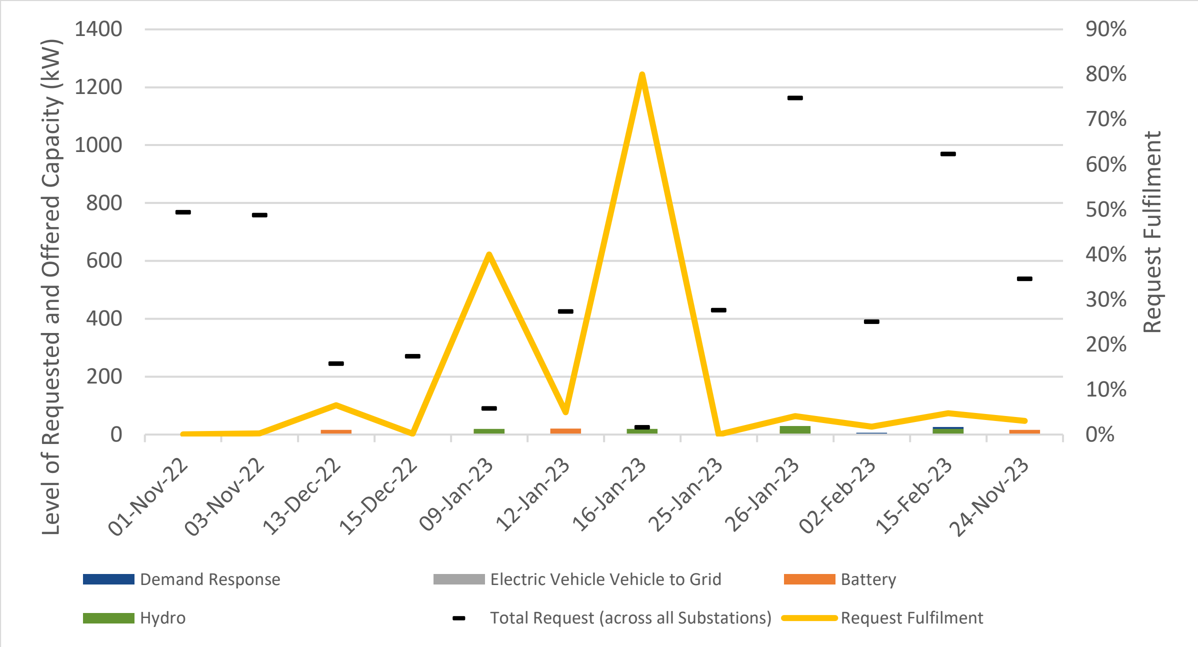


Figure 19: Response by DER type against requested capacity (with % of request fulfilment) for SCM.

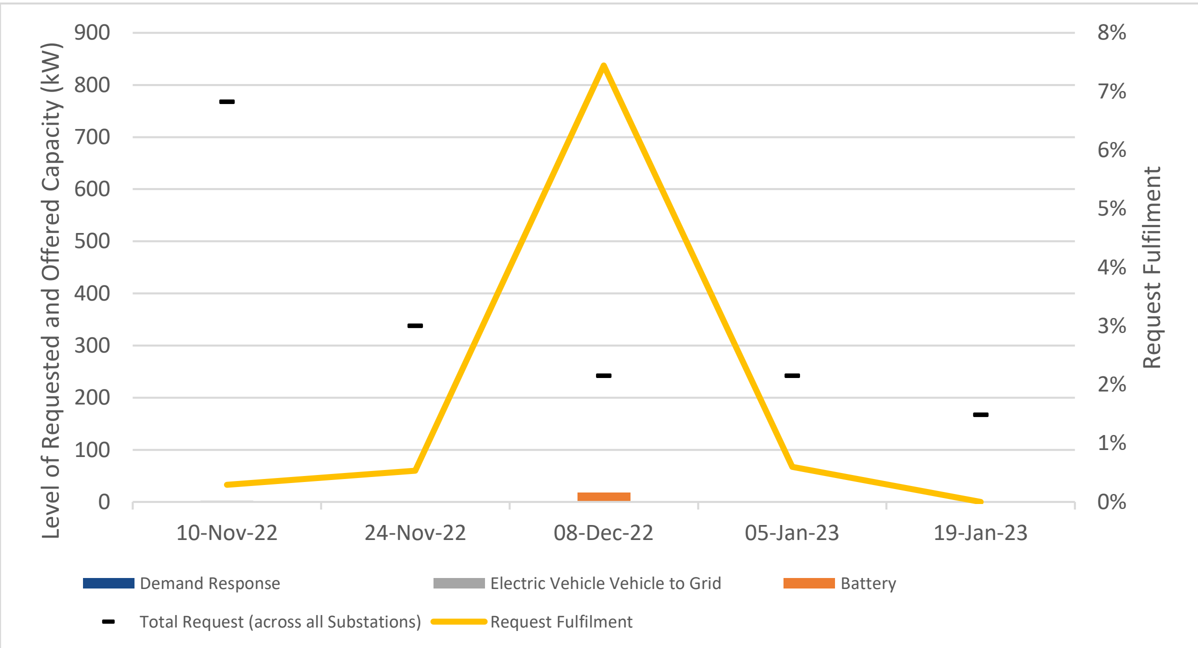


Figure 20: Response by DER type against requested capacity (with % of request fulfilment) for DCM.

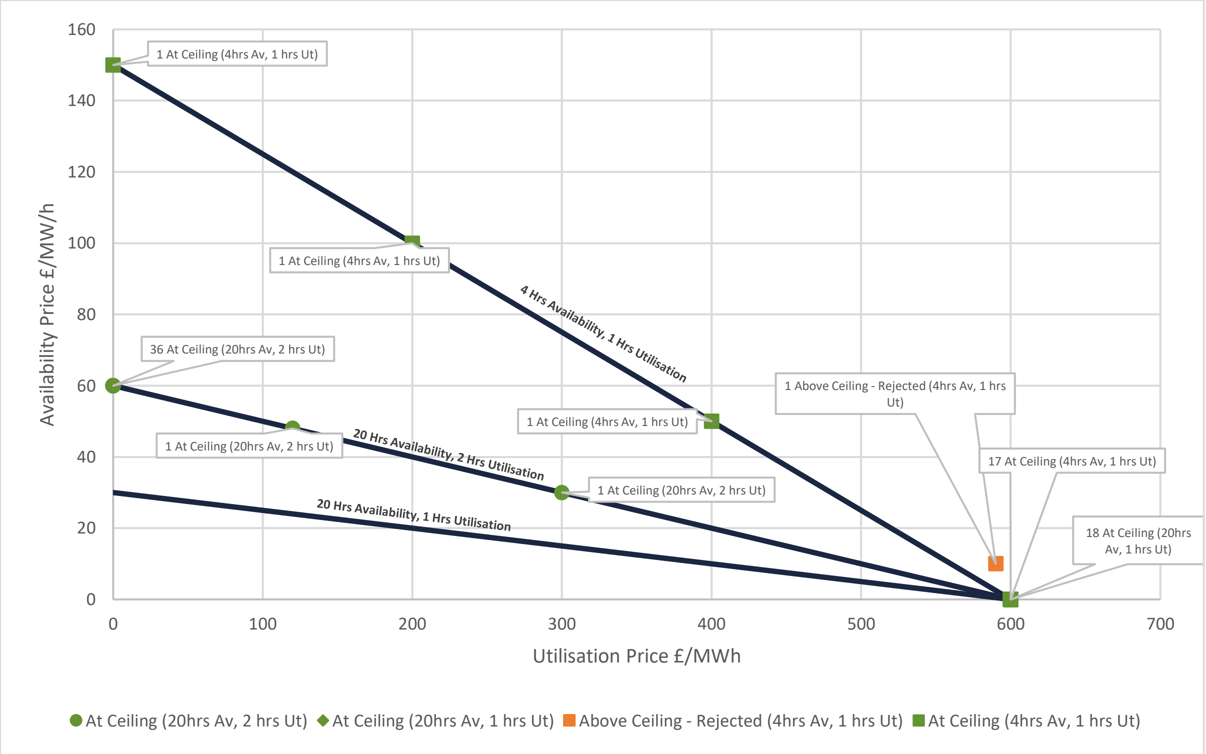


Figure 21: Utilisation Price vs Availability Price for SPM

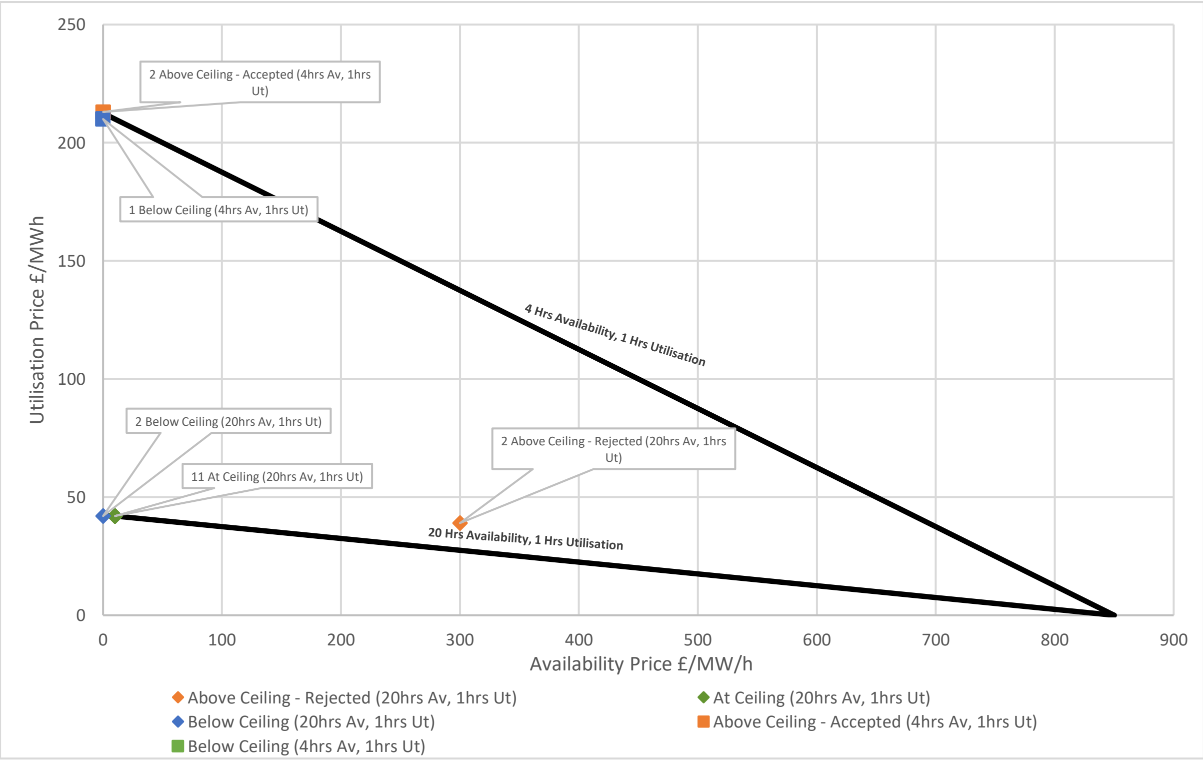


Figure 22: Utilisation Price vs Availability Price for SEPM

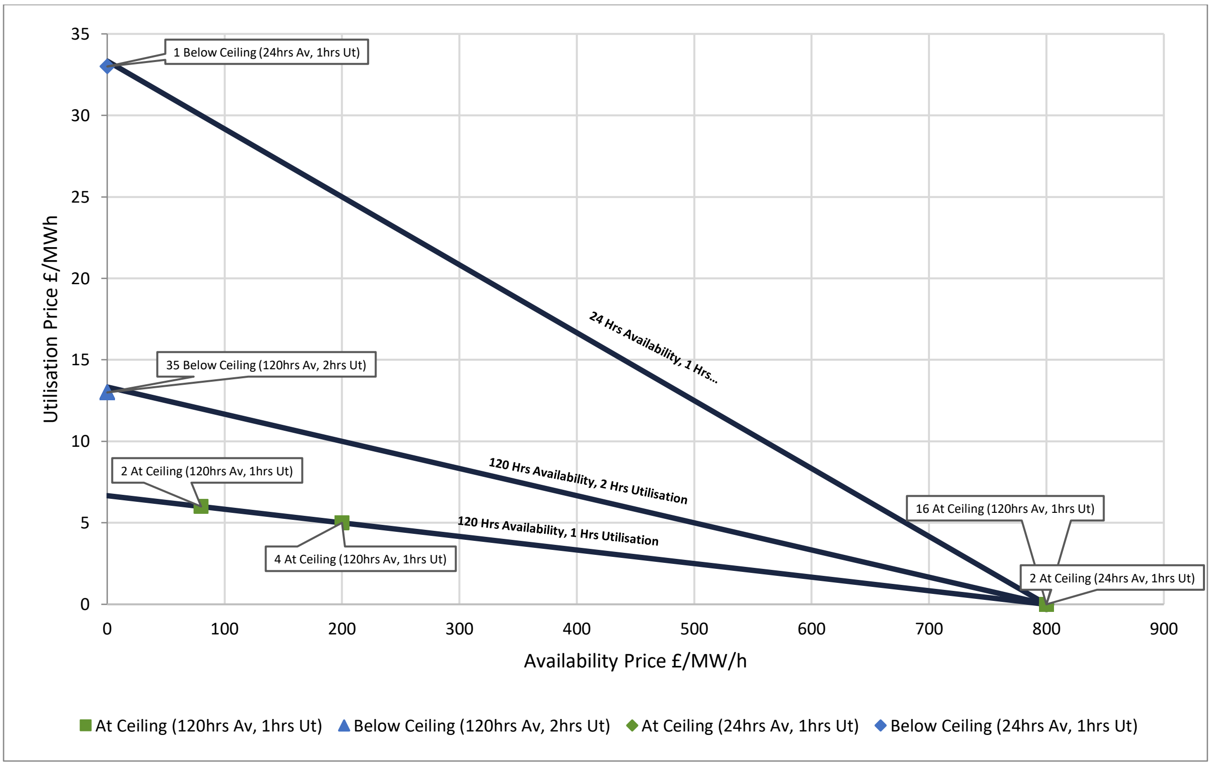


Figure 23: Utilisation Price vs Availability Price for SCM

Table 24: Summary all auctions in TP3

Substation (BSP and Primary)	No of Auctions	% of Auctions which resulted in a	Sum of Request Quantity (kW)	Sum of Response Quantity (kW)	Requeste d Fulfillment (kW)
Dynamic Constraint Management	**36**	**33%**	**5718**	**24.41**	**0%**
Bicester North BSP	6	0%	802	-	0%
Cowley Local BSP	6	50%	1346	16.75	1%
Drayton BSP	6	67%	1040	1.3	0%
Headington BSP	6	0%	650	-	0%
Oxford BSP	6	83%	976	6.36	1%
Witney Yarnton BSP	6	0%	904	-	0%
MEC	**11**	**0%**	**780**	**0**	**0%**
Bicester North BSP	2	0%	60	-	0%
Cowley Local BSP	2	0%	60	-	0%
Drayton BSP	2	0%	40	-	0%
Headington BSP	1	0%	500	-	0%
Oxford BSP	3	0%	90	-	0%
Witney Yarnton BSP	1	0%	30	-	0%
MIC	**6**	**0%**	**1654**	**0**	**0%**
Cowley Local BSP	2	0%	120	-	0%
Drayton BSP	1	0%	40	-	0%
Headington BSP	3	0%	1494	-	0%

Substation (BSP and Primary)	No of Auctions	% of Auctions which resulted in a	Sum of Request Quantity (kW)	Sum of Response Quantity (kW)	Requested Fulfillment (kW)
Secure Constraint Management	**86**	**33%**	**14007.5**	**212.42**	**0%**
Bicester Primary	3	0%	75	-	0%
Bicester North Primary	3	0%	54	-	0%
Bicester North BSP	12	8%	1704	2.5	0%
Kennington Primary	3	33%	330	0.05	0%
Rose Hill Primary	3	33%	75	16	21%
Cowley Local BSP	12	58%	3209.5	166.95	5%
Drayton BSP	13	62%	2385	9.37	0%
Headington BSP	12	8%	1550	2	0%
Oxford BSP	12	67%	2327	12.55	1%
Witney Yarnton BSP	13	8%	2298	3	0%
Sustain Export Peak Management	**46**	**24%**	**-14607**	**-604**	**2%**
Bicester Primary	1	0%	-70	-	0%
Bicester North Primary	1	0%	-90	-	0%
Bicester North BSP	7	0%	-3044	-	0%
Kennington Primary	1	0%	-25	-	0%
Rose Hill Primary	1	0%	-25	-	0%
Cowley Local BSP	7	43%	-2287	-41	2%
Drayton BSP	7	29%	-1716	-11	1%
Headington BSP	7	43%	-3310	-512	15%
Oxford BSP	7	29%	-2100	-19	1%
Witney Yarnton BSP	7	14%	-1940	-21	1%
Sustain Peak Management	**87**	**40%**	**12646**	**343.61**	**3%**
Bicester Primary	4	0%	100	-	0%
Bicester North Primary	3	0%	54	-	0%
Bicester North BSP	13	8%	1423	2.5	0%
Kennington Primary	4	50%	440	45.05	10%
Rose Hill Primary	4	50%	100	32	32%
Cowley Local BSP	13	69%	3244	119.45	4%
Drayton BSP	11	82%	1875	5.4	0%
Headington BSP	12	8%	1425	2	0%
Oxford BSP	12	83%	2139	136.21	6%
Witney Yarnton BSP	11	9%	1846	1	0%
Grand Total	**272**	**32%**	**49412.5**	**1184.44**	**2%**

Appendix B Glossary of Terms

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

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

The Terms and Definitions produced by the Open Networks 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
Bulk Supply Point (BSP)	A point on the transmission network, generally at 132kV level, where electricity is delivered to the DNO for delivery through its distribution network to users' premises.
Common Information Model (CIM)	A standardised file format, used as means to transfer data between different systems in a standardised manner.
Distributed Energy Resource (DER)	A Demand Asset, Generation asset or Storage asset connected to the Distribution Network that may be able to provide Flexibility.
Distribution Network Operator (DNO)	The organisation that owns, operates, and maintains the Distribution Network in one of 14 regional areas that delivers electricity to industrial, commercial and domestic users on behalf of Electricity Suppliers.
Distribution System Operator/Operations (DSO)	The functions and services needed to run a smart electricity distribution network in the interests of all Consumers / Prosumers. DSO functions will be delivered by a range of parties.
DSO-Enabled Services	Flexibility Services that are not procured by the DSO but that are traded between two peers on the network. In TRANSITION these are the trading of export capacity or trading of import capacity on a Peer-to-Peer basis. Although not procured by the DSO, it plays a role in enabling these to occur.
DSO-Procured Services	Flexibility Services that are procured directly by the DSO with the purpose of supporting the local distribution network in some way.
Exceeding MEC / MIC	To go above the contractually agreed maximum amount of electricity (expressed in kW or kVA) permitted by the DNO to be exported from your site (Maximum Export Capacity, MEC) or imported to your site (Maximum Import Capacity, MIC).
Extra High Voltage (EHV)	For these trials Extra High Voltage is 33kV.
Energy Costs	The electricity costs associated with the delivery of Flexible Service. Particularly for storage assets – for example, the main cost incurred for electric vehicles was the electricity costs associated with charging the vehicle before and after service.
Flexibility Services Agreement (FSA)	The Flexibility Services Agreement **(**FSA) is the legal contract between the DNO and the provider of Flexibility Services. It sets out, amongst other things, the terms of the trades, the expectations on both sides and any penalties for non-delivery of service. The TRANSITION FSA is based on an industry standard template developed through Open Networks.
Funding Asset Costs	Capital expenditure (CAPEX) associated with funding and enablement of DER to participate in flexibility markets.
High Voltage (HV)	For the purpose of these trials High Voltage is 11kV.
Legal Costs	Costs associated with legal reviews. During TP1, most significant legal costs were associated with reviewing of the trial contracts, particularly the FSA due to its length.

Term	Definition
Low Voltage (LV)	For the purpose of these trials Low Voltage is anything below 1,000V.
Maintenance Costs	Costs associated with any maintenance of a DER during participation in Flexibility Services.
Margin	The difference between the income from service and the amount of money required to produce it.
Monitoring & Control Costs	Costs associated with monitoring and metering of DER and any control required to dispatch its Flexibility.
Net Zero	We will have achieved 'net zero' when the amount of greenhouse gas we produce is no more than the amount being taken away.
Neutral Market Facilitator (NMF)	The TRANSITION Neutral Market Facilitator (NMF) is an IT platform that will in many cases automate the processes required around the procuring of flexibility services and will be connected to several other systems such as Forecasting and Power System Analysis tools. It has been developed to be transparent and non-discriminatory and has a key role in establishing markets for Flexibility Services. It can be used by those selling a Flexibility Service to; • find requests for those wishing to buy Flexibility Services. • submit responses to requests for Flexibility Services. • find if their response has been accepted or not. • find the instruction to deliver a Flexibility Service. • provide updates or changes to the availability of their DER. • find other instructions from the DNO/DSO; and • share their data to verify delivery of a flexibility service
Peer-to-Peer (P2P)	In the context of our trials, this means either a generator, storer or user of electricity who enters into a DSO-Enabled trade, with one peer being the seller and one the buyer. To do this both peers must be connected at the same point on the distribution network.
P2P Services	Flexibility Services traded between market participants (but not the DNO, DSO or ESO although any one of these entities may enable the trade) and includes DSO-Enabled Services.
P2P Term sheet	The P2P Term sheet contains the contractual terms both parties agree to comply to trade spare capacity.
Personnel Costs	Staff costs associated with participation in market, including pricing and interaction with the NMF.
Power Systems Analysis (PSA)	Assessments of the power flows and voltages on the electricity network using different demand and generation scenarios. PSA studies can be done across all timeframes, from long-term years-ahead for system planning, weeks/months-ahead for maintenance scheduling, down to the very short term for assessing the present network flows in real-time. The objective of PSA is generally to make sure that electricity network stays within allowable performance criteria for current and min/max voltages.
Service Stacking	The ability of a market participant to deliver more than one service in the same or adjacent half hour periods usually in multiple markets (i.e., DSO services, P2P services, ESO services) as a means of maximising revenue streams.

Term	Definition
Smart Local Energy Systems (SLES)	A Smart Local Energy System is one where local and national energy infrastructure, people/communities, and technologies work together in an intelligent integrated way to make, move, store, sell, use and conserve energy locally. A successful SLES creates value to the community it serves and should respond to the community's objectives.
Smoke Test	A series of tests used to check if the functionality of a system, from individual blocks to the entire system, work as expected. They are used to build confidence that systems and processes being used work as expected.
Sustain Peak Management (SPM)	A flexibility service most often used in 'winter tea time' situations in which the demand for electricity is predictably at its highest. Incorrectly managed this can create stress on parts of the electricity network. To prevent this, the DSO can procure this service some time ahead of need which can be provided by either an increase in generation, decrease in demand, or call on locally stored power in batteries.
Temporary Capacity Variation Notice (TCVN)	A notice that permits a temporary increase in either the maximum import capacity or maximum export capacity of a site. It is provided by the DNO to the party who wants to exceed their export or import capacity and may include some limitations.
Trial Period	The TRANSITION / LEO market trials are running in three calendar periods as follows. • TP1 started in October 2021 and ran until February 2022 • TP2 starts in May 2022 and runs until September 2022 • TP3 starts in November 2022 and runs until February 2023 The breaks between these three trial periods allow us to consolidate our learnings and use these to influence the plans for the next trial period. Each trial period will be testing the markets for a different set of flexibility services as well as increasing in their complexity as new technical and commercial elements are introduced.
Water Management Costs	Costs incurred with moving and storing water (particularly for river hydro) to enable DER to participate in flexibility service.
Whole System Coordinator (WSC)	The Whole System Coordination (WSC) is an IT tool that integrates data from a variety of different sources to quantify the requirements for network flexibility across different timeframes.