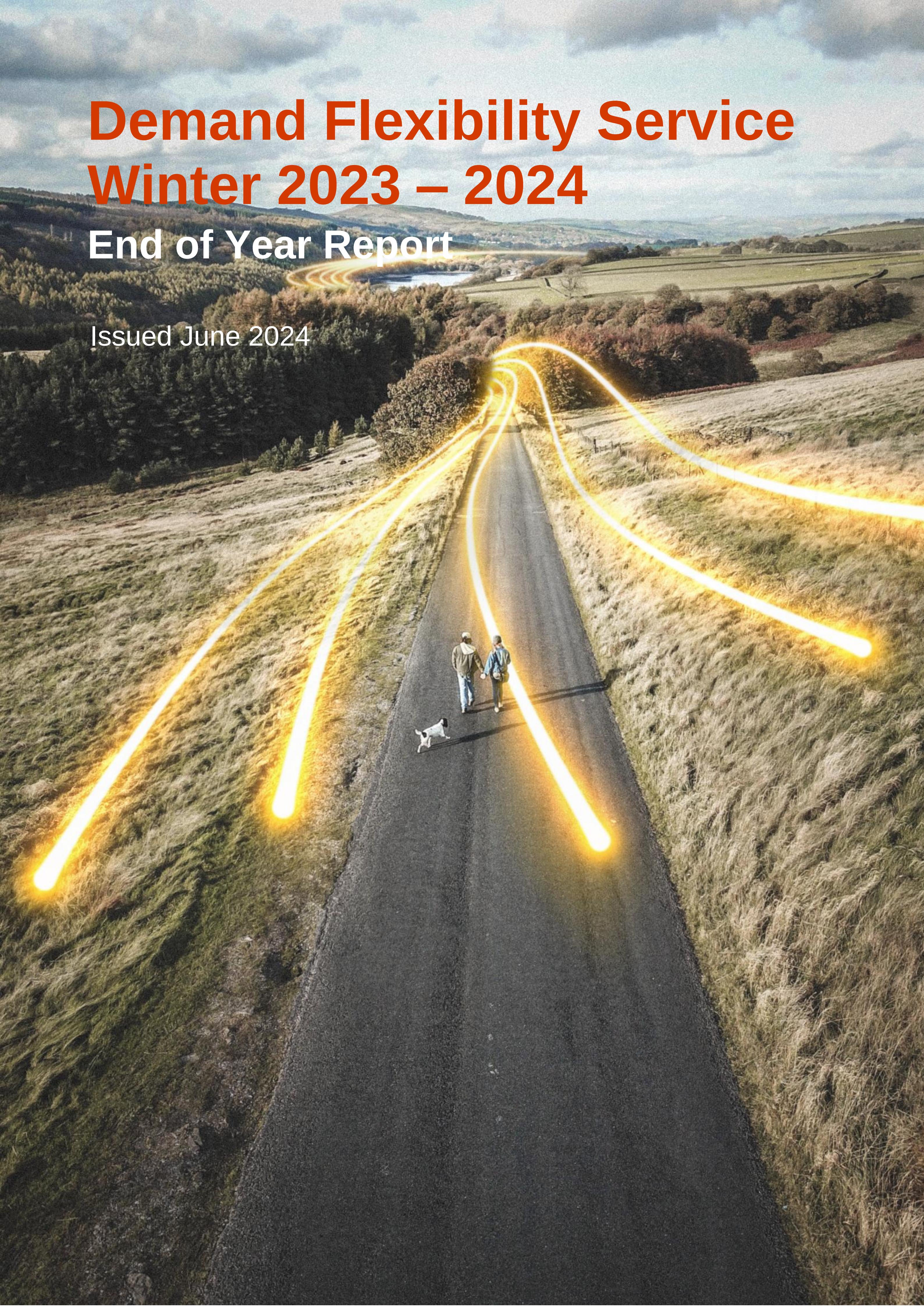
Demand Flexibility Service Winter 2023 – 2024

End of Year Report

Issued June 2024



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WHAT IS THE DEMAND FLEXIBILITY SERVICE?

The Demand Flexibility Service (DFS) was introduced during the winter of 22/23 as part of the winter contingency toolkit. Its purpose was to act as an enhanced action, in addition to the normal electricity market, to be used to access additional megawatts (MW) during times of high national demand, particularly on peak winter days when the system could have been placed under stress.

The DFS aimed to incentivise domestic consumers and industrial and commercial users through suppliers/ aggregators to voluntarily reduce/flex their demand. The DFS has been viewed as a pioneering initiative that allowed households/ businesses to participate in a flexibility market, lowering the entry barrier compared to established markets. The service gained recognition in the industry, winning the Whole Energy System Innovation category at the Green Energy Awards and the Net Zero Engagement category at the Utility Week Awards in 2023.

1. Executive Summary

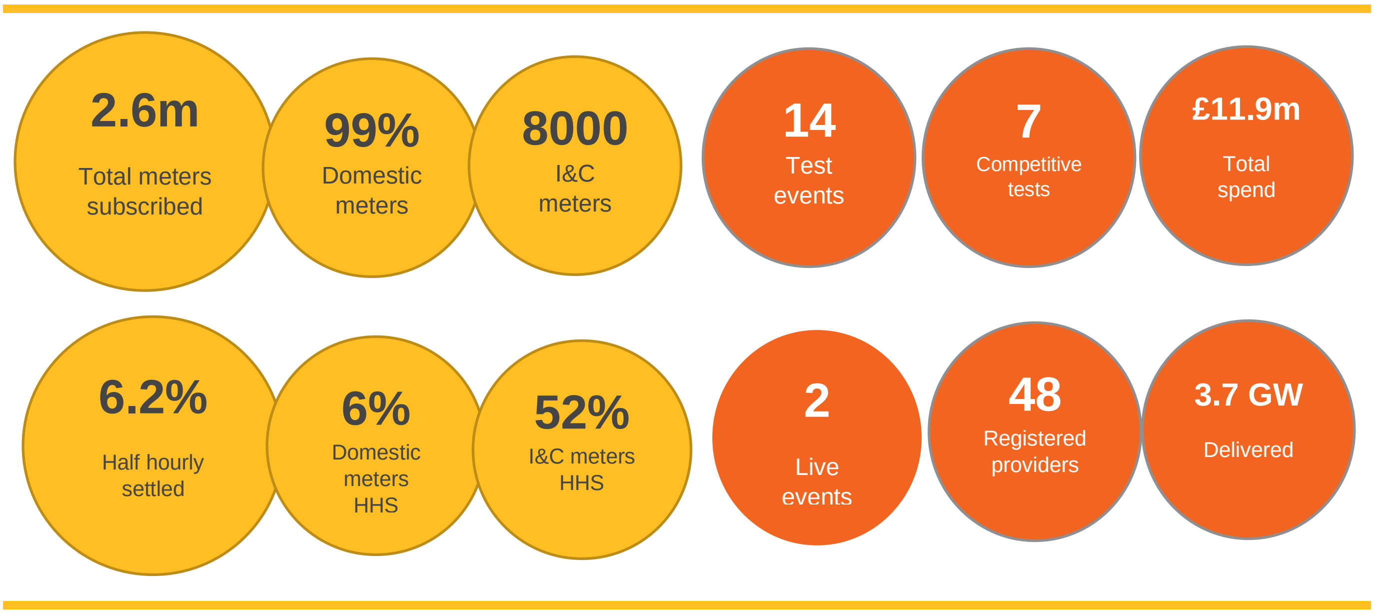
In September 2023, our Winter Outlook Report highlighted slightly higher base case margins for the upcoming winter, but also identified risks and uncertainties in the global energy markets. As a prudent system operator, we prepared for various scenarios to ensure the safe operation of the system and minimise the impact on electricity customers in Great Britain. To provide additional tools to maintain system margin during peak demand, we announced the continuation of the Demand Flexibility Service (DFS) as an enhanced action.

We conducted a European Balancing Regulations (EBR) Article 18 consultation, engaging with industry stakeholders to gather feedback and suggestions for improving the service. The consultation received significant engagement, with over 32 responses providing over 140 pages of feedback, leading to valuable insights in shaping the development of the service.

During winter 23/24, we witnessed a significant increase in the number of providers and participants in the DFS, showcasing its innovative nature as a world-first flexibility market. This report highlights the improvements, changes and learnings from the service that will help shape the evolution of DFS.

We believe that DFS can continue to play a crucial role in supporting system operations and providing additional margin during periods of high demand. We remain committed to refining and expanding the service to meet the evolving needs of the energy market and ensure a reliable and secure electricity supply for Great Britain.

2. Winter 23/24 overview



During the winter 2023/24 period the DFS reached 2.6 million subscribed meters, with 99% of them belonging to domestic consumers. The remaining meters, around 8,000, were from the Industrial & Commercial (I&C) sector. Among the total number of subscribers, 6.2% were half-hourly settled, accounting for 32% of the delivered volume. Comparatively, 6% of domestic meters were half-hourly settled, while 52% of I&C meters had this settlement type. The number of registered providers increased by 58% compared to the previous year, reaching a total of 48.

Of the consumer classification, over 99% were categorised as "Manually Initiated," while the rest fell under the "Directly Instructible" category, responding with some form of automation.

During the period, there were 14 test events, with 7 conducted under competitive conditions. In competitive tests, bids as low as £150/MWh were submitted, and the average accepted bid was £1110.9/MWh. Additionally, there were 2 live events. The total spend for the DFS winter 2023/24 was £11.9m, and over 3.7 GWh was of energy delivered, with a peak energy delivery of over 400MW.

3. DFS Developments and learnings from 2022/23 to 2023/24

Outlined below are the core developments which were introduced for the second year of operation. The majority of these were shaped with industry from the feedback and support provided in developing the service. For further insights into the contractual and guidance documents of the service please refer to Appendix 1.

New procurement times

ESO introduced two new within-day procurement windows for winter 23/24 with the day-ahead option from the previous winter remaining.

Window	Time
Day ahead	14:30
Within day (AM)	09:00
Within day (PM)	12:00

Table 1 – Procurement windows

The new procurement windows aimed to bring the service closer to real-time allowing us to understand the impact that different lead times have on the volume of flexibility available and support our operational decision making which are covered later in this document.

ESO recognise that moving the service closer to real time is in line with the European Balancing Regulations and something that was identified in Ofgem's approval letter. Overall, we have seen from winter 23/24 that the experience of operating within day procurement windows demonstrates the volume can both be accessible and accurately deliver, however in evolving the service, given the large volume that is manually instructed finding the correct balance to provide adequate notice for consumers is going to be crucial.

Automation

ESO were able to make several changes to the processes around various data submissions. The introduction of an Application Programming Interface (API) across several of the processes allowed parties to enhance their automation for participating in the service. This in turn supported improving the Meter Point Administration Number (MPAN) check process from weekly to daily facilitating a more dynamic update of parties' portfolio and consumers ability to move between registered service providers more freely.

These improvements were welcomed by industry and we have received positive feedback on these with a strong desire for this to continue in future iterations. 48% of the active participants used the API and this accounted for 98% of the total MPANs registered proving how essential it was this winter. Several other participants indicated they were keen to add and invest in an API if the service becomes more enduring and continues for successive winters and / or becomes an all-year-round service.

Systems

There were some technical issues identified for the first few events where text message notifications were not received by all parties through the data portal. In response to this, we agreed an interim solution to send out additional email notifications for Anticipated DFS Requirement Notices and DFS

Service Requirements. It was noted that the text message facility was not utilised widely across the data portal data sets and should further API enhancements be made this may not be necessary in the future.

We did learn that parties with a particularly large number of customers did have challenges at times submitting their files to our SharePoint. This is due to the large data sets that are being transferred and number of files that had to be sent. This has presented a strong case for us to seek to expand our API to settlement files for subsequent service improvements.

Standardised ownership rules for MPAN's

Clearer rules were incorporated into our contractual documents outlining that providers with the latest timestamp for the sign-up of a Unit Meter Point (MPAN) would be deemed to be the sole provider for that end consumer. The provider with an older sign-up timestamp would be obliged to de-register the meter from their portfolio. This was introduced to provide a clear, unambiguous rule to avoid MPAN ownership duplication, which provided challenges in winter 22/23 for providers, end consumers and the ESO.

A handful of providers had some confusion with the validity of MPANs after registration. They considered the MPAN(s) were available for the event window settlement period but had not considered they needed to be registered in time for the bid window period. These issues have shown improvement as the events progressed via Performance Monitoring and Service Terms educational discussions.

Unfortunately, ESO did see evidence that a minority of providers were not following the updated rules regarding the validity date of a new MPAN with a knock-on impact across broader portfolios and ultimately end consumer experience. ESO were able to correct these quickly and efficiently through our internal governance checks and communicated with the providers the importance of fully understanding and following the contractual obligations they had signed up to. No further action was required following swift resolution of fully understanding this rule change. We acknowledge that this was an exception and is a challenge when operating a portfolio of over 2.6m meter points under a service. Going forward ESO will continue to ensure that all parties are operating under the same set of rules and take appropriate action where necessary should we see adverse behaviour.

Broadly speaking introducing this rule significantly reduced the number of duplications witnessed and from ESO's perspective has provided a clear mechanism for parties to follow should the onboarding and customer acquisition process result in duplicated MPANs.

The introduction of settlement data at MPAN level has offered ESO better granularity of visibility for the settlement calculation. Whilst we recognise this is an increase of data for parties to share it has been a worthy amendment as our market monitoring team have been able to carry out detailed checks, and these have assisted providers to improve their processes and accuracy. This has helped to further avoid discrepancies within the settlement process bolstering our governance checks, ensuring value for money for consumers.

Tests

Onboarding and ‘Regular’ tests were replaced with ‘DFS tests’ for all providers simultaneously following learnings from year 1 in managing a large volume of providers and maximising the learning from each test event.

ESO issued our first Market Information Report (MIR) in August 2023 and outlined our expectations to run 12 tests events between October 2023 and March 2024. The first 6 test events (phase 1) would remain with a Guaranteed Acceptance Price (GAP) of £3000/MWh and we would endeavour to complete these before the end of December 2023. The remaining test events (phase 2), between January 2024 and March 2024, would either continue to be underpinned by the GAP or become competitive, subject to us reaching a volume threshold outlined in the MIR or if system conditions allowed. Further details and a deeper analysis of the test and live events are covered later in this report.

Bid Submissions

Overall ESO saw a variance in terms of the level of support required for providers when a bidding window opened compared to our other services. An area we would value seeing an improvement in would be a greater level of awareness from providers for actioning information being shared on the data portal when service requirements are issued. There was an expectation from some parties to receive personalised notifications to remind them to bid which as the service continues to grow and evolve is unlikely to be feasible. ESO acknowledge that the data portal text notification process did have challenges and this is something that may be removed moving forward due to its reliability and level of uptake. ESO’s account managers were on hand for all events to support parties who had challenges around the bid submission process. The target areas for further automation should help further improve the challenges around this topic.

Early in winter 23/24 several providers had issues submitting valid bids, specifically around an error message of “Incorrect settlement period”. This was found to be an internal assessment tool bug which we were able to rectify but did create some confusion in why bids were being rejected. This is something that we are feeding into validation improvements moving forward.

Asset Metering Introduction

Following feedback from industry, we incorporated the ability for providers to participate in DFS with sub (asset) meters, as well as boundary meters whilst mitigating the risk of diluting the volume and the risk of gaming. The asset meters were required to be of the same or better standard than the boundary meter and be related to a Half Hourly (HH) Settled boundary meter. The asset and boundary meters could not participate at the same time. All asset meters associated with a boundary meter controlled by the provider had to be entered for the service, although, the provider could choose to opt-in or opt-out for each event. To support our market monitoring, we reserved the right to request boundary meter and asset meter data for audit purposes.

As outlined in our Winter 23/24 numbers earlier in the document the uptake of asset metering particularly on the domestic side was low. As a result, we were unable to gain a good data set to fully understand the capability and implications of asset meter participation. Provider feedback particularly from the aggregator community has cited the challenges around consumers knowledge about whether they are HH settled or how they can request to be played a role in the uptake. This is something that we will seek to further explore as the service evolves.

Baseline Methodology within-day adjustment

Following feedback from providers of the DFS 22/23 service, there was a concern the within-day baseline adjustment for Domestic meters could lead to perverse incentives. To mitigate this risk we applied the agreed industry methodology based on P376 without the within-day baseline adjustment. The same baseline methodology for Domestic and Industrial & Commercial (IC) meters was applied.

Our engagement with industry to date on the baseline methodology has demonstrated this is a broader challenge that distributed energy resources face across a host of markets. Through our market monitoring and performance review of the data from winter 23/24 there have not been any immediate changes which we see value and benefits in making to the baseline methodology but have seen a positive reaction to the within day adjustment as a mechanism towards actively mitigating any perverse incentives. We recognise that this is a topic that we will need to continue to monitor and review and will be interested to take on board the learnings from other markets where alternative methodologies are applied.

Opt-in and Opt-Out

Previously in 22/23, each consumer had to opt-in to the service and each DFS event. For winter 23/24, providers could offer their end consumers different options of opting in or opting out to indicate if they wanted to participate in a DFS event. Consumers could also opt-in as 'default' to each event until they choose to opt-out.

The introduction of this rule allows less communication from DFS providers with end consumers and as delivery accuracy might be negatively affected the opt-in as 'default' was combined with a requirement that the settled volume will not be capped at zero if end consumers did not turn down, but instead increase, meaning that this volume will be net-off from any payments from the ESO.

This communication relaxation was used by approximately 73% of the registered directly instructible assets. Nevertheless, it is worth highlighting that a very small percentage of meters used this option and understand that the risk of some consumers non-delivery to others in a providers portfolio was too big a risk from a customer experience perspective. Typically, we heard from providers that this option better suited more automated setups.

Applicable Balancing System Volume Data (ABSVD)

Applicable Balancing Service Volume Data (ABSVD) is a mechanism for ensuring that Lead Parties are not exposed to Imbalance Charges when assets within their BM Units deliver certain Balancing Services to the ESO.

For DFS, ABSVD was only required for Half-Hourly (HH) settled volume as per the complexity of the data and the proportional impact on load-profiled demand. The impact of not applying ABSVD to non-HH settled volume is minimised by the fact that the net change in the supplier's imbalance position is small, as the overall imbalance is shared across multiple Settlement Periods and across all suppliers in each GSP group, due to the way Elexon's load profiles work (i.e. average load profiles and Group Correction Factors).

The most common method to apply ABSVD is via a BMU ID process, however this can be difficult for DFS non-Supplier providers due to market data availability. Finding out the HH Settlement status and BMU ID for the assets of non- suppliers is a challenging task. To obtain this information they require the meter's supplier of electricity support to obtain the most accurate information and to then provide this to ESO for applying ABSVD.

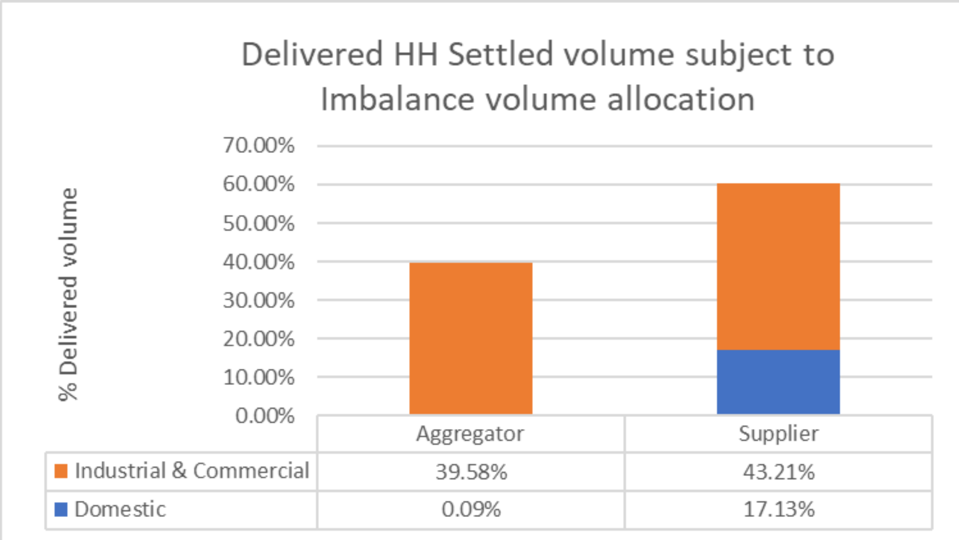


Table 2 – Delivered HH settled volume subject to imbalance volume allocation

As a result, DFS 2023/24 established the following rules:

- HH Settled Domestic customers who were taking part via their Electricity Supplier, ABSVD was applied via BMU ID. The benefits are:
  - Risk mitigation of HH Settlement and BMU ID data availability issues for Aggregators (non-Suppliers)
  - Better utilises ESO, ELEXON and providers resources by minimising high number of MPANs to be ABSVD under another ABSVD methodology like P354. For DFS 2023/24 we had 156,125 MPANs HH Settled represented by their Supplier of Electricity, this rule avoided requesting for consent to all these domestic households. Instead, their imbalance volume got allocated against a maximum of 90 BMU IDs, facilitating data sharing with ELEXON.
- HH settled Domestic customers represented via Aggregators, ABSVD was not applied:
  - Aggregators have market data limitations such as BMU ID and HH Settlement status.
  - There is a low percentage of HH Settled Domestic (based on ELEXON database approx. 4% nationwide[1]) and based on DFS 23/24 Suppliers' portfolio the projected HH Settled Domestic meters proportion is roughly 0.5%[2] of total participating volume.
  - The population affected by this route is reduced as it only excludes domestic customers represented by Aggregators (roughly 6.51% based on DFS 23/24 Domestic meters represented by Aggregators).
- HH Settled Industrial and Commercial ABSVD process ran under P354 methodology. This mitigated BMU ID data availability issues for Aggregators, facilitating a viable route to allocate 10.68% of the total DFS Delivered volume in 2023/24.

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[1]Source: Gross Supplier Market Share Data reports - Elexon BSC

[2] $$\textit{Projected HH Settled Domestic meters volume \%} = \frac{\text{HH Settled Domestic meters volume \% represented by Supplier}}{\textit{HH \& NHH}\text{ Settled Domestic meters volume \% represented by Supplier}}\ x\ \textit{Domestic meters volume \% represented by Aggregators} = \frac{5.44\%}{7.10\%}\ x\ 6.51\% = 0.5\%$$

We introduced ABSVD to mitigate the risk of unallocated imbalance volume. To support the challenges faced from different segments when applying ABSVD and obtaining the data, we applied the rules above and as result enable a more efficient process and customer journey for over 100k meters.

Table 3 below shows segments by HH settlement status and ABSVD approach.

Segment Type	Represented by	HH Settlement Status	ABSVD
Domestic 73.61% 2,567,232 meters	Supplier or Supplier Representative 67.10% 2,463,476 meters	HH Settled 5.44% 156,125 meters	ABSVD via BMU ID
		Non HH Settled 61.66% 2,307,351 meters	No ABSVD
	Aggregator 6.51% 103,756 meters	HH Settled 0.02%[3] 1,834 meters	No ABSVD (Imbalance volume not allocated)
		Non HH Settled 6.49% 101,922 meters	No ABSVD
Industrial & Commercial 26.39% 8,711 meters	Supplier or Supplier Representative 15.69% 7,668 meters	HH Settled 15.6% 3,409 meters	ABSVD via MPAN details (P354)
		Non HH Settled 0.09% 4,259 meters	No ABSVD
	Aggregator 10.70% 1,043 meters	HH Settled 10.68% 1,029 meters	ABSVD via MPAN details (P354)
		Non HH Settled 0.02% 14 meters	No ABSVD

Table 3 – Settlement status by segment type

[3] this only represents one Aggregator volume who had access to HH Settlement status for its customers. Aggregator – Domestic meter HH Settlement status was optional.

Improved and legally binding Communication Principles

Communication Principles were developed alongside industry feedback to form a set of standards and expected behaviours for all Registered DFS Participants to follow. They were designed to help enable Registered DFS Providers and consumers to participate in DFS safely and effectively. The Communication Principles were strengthened by aligning them with an obligation under the DFS Procurement Documentation to ensure compliance of Registered DFS Participants.

DFS further developed the communication principles to support transparency to end consumers. This included rules around consent for Providers, which was legally binding to the terms of the service for additional governance.

Whilst it is challenging to measure the success of these changes, we recognise that ensuring all providers have a robust set of expectations and rules to follow is an important aspect. ESO are also involved in wider work around offering consumer protection and assurance through schemes such as HomeFlex and FlexAssure. These were featured on our DFS webpage for end consumers to access and from the record-breaking traffic our DFS webpages saw in winter 23/24 we see value in ensuring these remain visible on our external webpages.

4. Event Analysis

This section provides a breakdown of the data from the test and live events. The analysis includes the correlation between forecasted volumes and actual delivery results, the types of providers participating, the overall spend and regional participation.

This year, the introduction of two within-day procurement windows allowed for closer investigation of the impact varying procurement timescales had on bidding and delivery volumes as well as the difference in operational certainty when calling an event. Competitive pricing was also introduced in the final seven test events to assess its effect on both price and delivery of the service.

The tests conducted have been crucial in understanding the accuracy of providers' forecasts, their delivered volumes and pricing across different procurement windows. They have played a vital role in making DFS commercially viable for both providers and end-consumers, building confidence and providing operational learnings. These insights will help shape and develop the service as it evolves, allowing for a better understanding of this type of consumer flexibility and its potential benefits.

Table 4 shows the distribution of meters by their Grid Supply Points (GSP).

Region	Number of meters	Percentage
East England	304373	11.8%
East Midlands	252042	9.8%
London	107567	4.2%
Merseyside & Cheshire	118518	4.6%
North East England	141889	5.5%
North Scotland	43024	1.7%
North West England	189640	7.4%
South East England	201622	7.8%
South Scotland	127870	5.0%
South Wales	82164	3.2%
South West England	144692	5.6%
Southern England	263656	10.2%
West Midlands	204872	8.0%
Yorkshire	199151	7.7%
Other	194766	7.6%

Table 4 - Distribution of meters by Grid Supply Point (GSP) groups

DFS Forecast Accuracy & Performance

This section provides a detailed breakdown of all the events with Table 5 offering a headline summary of the delivery and total spend across all events from winter 23/24

Month	Tests Events		Live Events	
	Delivery (MWh)	Cost (million £)	Delivery (MWh)	Cost (million £)
Nov 2023	204.6	0.6	515.2	2.3
Dec 2023	1457.8	4.4	490.8	2.5
Jan 2024	409	1.2	0	0
Feb 2024	490.1	0.8	0	0
Mar 2024	192.4	0.1	0	0
Apr 2024	0	0	0	0
Total	**2753.9**	**7.1**	**1006**	**4.8**

Table 5 – Delivery and total spend by month for test and live DFS events.

Overall, the test regime implemented for winter 23/24 led to a reduction of ~£0.9m compared to what was spent on tests for the previous winter. Introduction of competitive tests contributed in a large part to this reduction. Furthermore, the minimum test duration was changed from 60 to 30 minutes so more tests could be performed offering additional insights over varying time periods of delivery.

Figure 1 below shows the MW procured vs the MW delivered for each DFS event. For the first few events the forecasts were less accurate, however, these significantly improved in accuracy as we progressed through the winter. We can see that for the first five events, overall delivery was less than the procured quantity. From the sixth event forwards, overall delivery closely matched the procured quantity. Feedback from providers noted the two new within-day procurement windows were an unknown and this contributed to some of the early forecasting.

From domestic delivery we have received feedback that the early inaccuracies were linked to parties establishing the behaviour and participation uptake within their portfolios and that once consumers were back into the understanding and mechanisms to the service this provided the step change in accuracy.

On the industrial and commercial side any inaccuracies were predominantly driven by sector specific drives such as weather or operational circumstances.

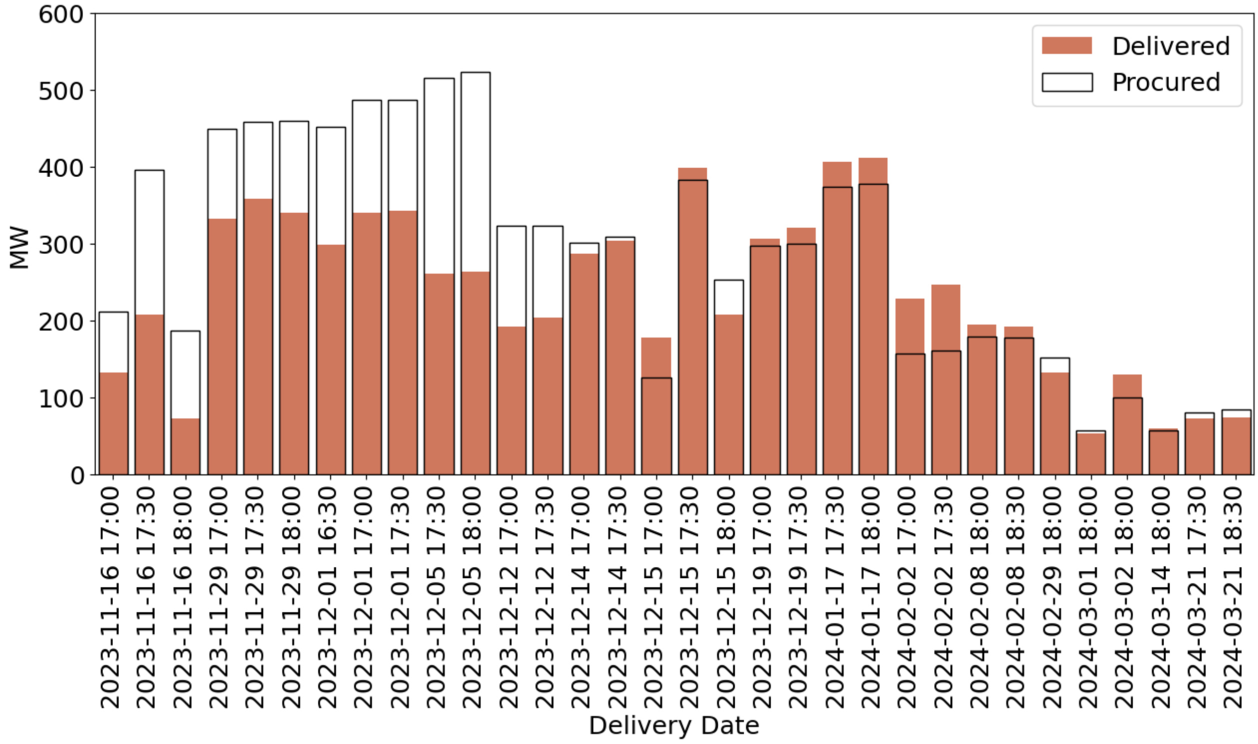

Figure 1 – MW procured vs MW delivered.

Delivery Accuracy

To explain in detail the trends in delivery from DFS events it is useful to first define the terms used to quantify service performance.

The difference between the delivered and procured quantities of demand reduction in MW is defined as the variation:

$$variation_{i,j} = Delivered_{i,j} - Procured_{i,j}$$

where

Deliveredi,j refers to the demand reduction delivered from Unit i during the contracted period j.

Procuredi,j refers to the demand reduction procured from Unit i during the contracted period j.

The difference between the delivered and procured quantities of demand reduction, as a percentage of the procured quantities, is defined as the percentage variation:

$$pct\_variation_{i,j} = 100 \cdot \frac{Delivered_{i,j} - Procured_{i,j}}{Procured_{i,j}}$$

Test & Live Events Detailed Review

A total of 14 test events along with 2 live events were run over the winter. For the first 7 tests a Guaranteed Acceptance Price (GAP) of £3,000/MWh was in place. For the tests supported by the GAP the volume requirement was set based on the weekly indicative forecasts to allow the ESO to accept all bids at or below the GAP threshold. However, as system conditions improved from February, following the first 7 tests, the GAP was revised to £0/MWh and different requirements and procurement windows were set to allow us to investigate the impact of different volumes on both price and delivery of the service. In this section, we have summarised the events into 3 parts, the live events, test events 1 to 7 with a GAP and test events 8 to 14 without a GAP.

Live Events Summary

ESO introduced a day ahead strategy team to support our operational processes heading into winter 22/23 and this team continued to play a pivotal role in working with our control room to determine any live activation of the DFS in 23/24. This team conducted assessments at the day ahead stage to identify whether available supply was able to meet the forecasted demand and positive margin required, which on two occasions led to live events being run. Reserve requirements are set based on reliability standards to secure the grid.

The day ahead assessment considers potential trades on the interconnectors and maximum generation volumes using the available information at the time to inform the decision. Information such as market surplus within neighbouring countries was considered in the assessment through morning calls held with other Transmission System Operators.

As detailed within winter order of actions, market-based solutions alone would not be able to meet reserve requirements and so enhanced actions were deemed necessary.

The circumstances which led to this requirement at day ahead (DA) are as follows:

- Uncertainty with DA interconnectors (IC) profiles and availability to trade on ICs.
- Unavailability due to outages.
- Generation availability was broadly in line with Winter Outlook expectations.
- Cold weather led to high demand (top 5% Winter Outlook range).
- Low wind output (lowest 2-5% of Winter Outlook range).

Within-day forecasted DFS volumes were not sufficient to cover the margin deficit and as such day ahead activation was recommended for both live events.

Detailed data for live activations is shown in Table 6. Negative variation between procured and delivered volume was observed in both live activations, meaning that overall delivery was less than procured quantities. Following feedback from providers this may be due to the desire and appetite to provide maximum support for what was forecasted to be a very challenging operational period. ESO also notes that these live events featured early in the operational go live and there were still learnings from providers around understanding and shaping the accuracy of their forecasts which was highlighted earlier in this document.

Delivery Date	From	Despatch Time	Procured MW	Delivered MW	Variation %	Payment
29/11/2023	17:00	day-ahead	449	332.4	-26.0	£776,213
29/11/2023	17:30	day-ahead	458	357.7	-21.9	£774,327
29/11/2023	18:00	day-ahead	459	340.3	-25.9	£748,946
01/12/2023	16:30	day-ahead	452	298.8	-33.9	£746,458
01/12/2023	17:00	day-ahead	487	340.3	-30.1	£851,689
01/12/2023	17:30	day-ahead	487	342.6	-29.7	£865,995

Table 6 – Live Events Data

Test Events 1 to 7

The first six test events had a Guaranteed Acceptance Price (GAP) of £3000/MWh, whilst the remaining tests would retain a GAP subject to participating volumes or system conditions. Part of this first tranche of tests was to ensure we kept the price variable the same to understand how the new procurement timescale impacted delivery and volume as we moved closer to real time.

Test 1 aimed to reflect the previous winter's service, allowing providers to test their processes based on the service modifications made from year 1 to year 2. The requirement was 500MW, staggered across three settlement periods (SP) to minimise operational impact. There was significant variation in delivered volumes compared to procured volumes, these are shown in table 4 below.

Test 2 tested the first within-day AM window, and there was still variation in the delivered volume against the procured volume.

Test 3 tested the second within-day PM window and included two additional tests in the same week to assess the impact of multiple activations.

Test 4 assessed the impact of calling the service twice in one day for two different delivery days.

Test 5 tested providers' ability to deliver two events in quick succession. Both tests showed improvements in delivered volumes compared to procured volumes. In line with earlier figure 1 this was when we saw a considerable step change in the consistency and accuracy of bid vs delivered.

Test 6 completed the plan to run two tests in each procurement window ahead of Christmas. There was a significant increase in delivery against procurement, with volumes reaching 103% and 107%.

After testing each delivery window and two live day-ahead events, ESO shifted focus solely on within-day tests to maximise learnings for calling the service closer to real-time which aligns with the regulatory expectations. With volumes still below the threshold and system conditions remaining tight the Guaranteed Acceptance Price remained at £3,000/MWh.

Test 7 delivered the highest volumes yet, with 103% and 109% delivery against procured volumes.

These test events provided valuable insights and will help us refine the service for better performance and delivery.

Delivery Date	Test	From	Despatch Time	Procured MW	Delivered MW	Variation %	Payment
16/11/2023	1	17:00	day-ahead	210	130.4	-37.9	£195,627
16/11/2023		17:30	day-ahead	395	206.6	-47.7	£309,972
16/11/2023		18:00	day-ahead	186	72.2	-61.2	£108,270
05/12/2023	2	17:30	within-day 1	515	260.8	-49.4	£391,236
05/12/2023		18:00	within-day 1	523	262.7	-49.8	£393,987
12/12/2023	3	17:00	within-day 2	323	191.9	-40.6	£287,820
12/12/2023		17:30	within-day 2	323	203.7	-36.9	£305,622
14/12/2023	4	17:00	within-day 1	301	286.1	-5.0	£429,219
14/12/2023		17:30	within-day 1	309	302.8	-2.0	£454,185
15/12/2023	5	17:00	day-ahead	126	177.4	40.8	£266,037
15/12/2023		17:30	day-ahead	382	398.4	4.3	£597,558
15/12/2023		18:00	day-ahead	253	206.6	-18.3	£309,936
19/12/2023	6	17:00	within-day 2	297	305.5	2.9	£458,238
19/12/2023		17:30	within-day 2	300	319.7	6.6	£479,490
17/01/2024	7	17:30	within-day 1	374	406.3	8.6	£609,522
17/01/2024		18:00	within-day 1	377	411.7	9.2	£617,580

Table 7 – Test Events 1 to 7 with a Guaranteed Acceptance Price (GAP) of £3000/MWh

Test Events 8 to 14 (Competitive Phase)

In January 24, an updated Market Information Report was published identifying that system margins were expected to increase as we progressed into the remaining winter period. As a result, the volume of DFS needed to maintain a similar risk level would decrease. To adapt to this, the testing schedule for the remainder of Winter 23/24 was adjusted to factor this change in landscape moving towards competitive bidding conditions. We were mindful that this was a key consideration outlined in Ofgem's approval letter of the service.

Under the new approach, the Guaranteed Acceptance Price was set to £0/MWh, and a volume requirement was established to encourage price competition among Registered DFS Participants. This change aimed to develop an understanding of delivery capabilities for within-day procurement and gain insights from competitive bidding conditions. These additional insights are beneficial to inform the long-term evolution and positioning of any future demand flexibility service. ESO do acknowledge that we artificially created the competitive conditions, and the number of events and participation levels mean the data set does have limitations but still provides useful market insights.

Test Event 8 (02-02-2024) was the first competitive test, with a 200MW requirement for the Within-Day PM period. Bids ranged from £1,000/MWh to £5,799/MWh, totalling over 350MW of volume bid. Previous tests had a GAP of £3,000/MWh, which providers believed was necessary for market growth and service viability. Bids at or above £3,000/MWh were considered uneconomic and rejected. At a price of up to £2,500/MWh, we were able to fill ~80% of the service requirement, signalling the need for the market to compete at lower prices. While not all providers were successful, bids from a broad pool of providers were accepted ensuring we had a good range of parties which helped our learnings. With accepted bids ranging from £1,000/MWh to £2,500/MWh a maximum volume of 161MW was secured with an average price of £1,893/MWh.

Test Event 9 (08-02-2024) set out our objective to gain further insight into within-day delivery capability, delivery volumes and forecast accuracy, and to assess how the outcome of Test Event 8 influenced participants under a competitive requirement. The test targeted a significant proportion of available volume from a diverse group of service participants, with volumes consistent with the first competitive test for direct comparison. The test took place in the Within-Day PM period (12:00) with a service requirement of 175 MW, equivalent to 80% of the de-rated forecast volumes for the target period. The total tendered volume was 346 MW, close to the volume registered in the first test, despite the later dispatch time. Bid prices ranged from £1,000/MWh to £3,000/MWh and we accepted bids ranging from £1,000/MWh to £1,725/MWh securing a maximum volume of 179MW with an average price of £1,498/MWh.

From February 29th to March 2nd, we ran three consecutive tests 10, 11 & 12 for Settlement Period (SP) SP37-18:00 to 18:30). Across all previous events delivery volumes were consistent across multiple settlement periods therefore the duration of the tests was reduced to one settlement period to explore the impact of a shorter window and to gain insights into the interaction between volume and price. Running shorter tests proved to be more cost-effective.

Test 10 (29-02-2024) set a requirement of 125MW in the within-day PM window to simulate closest real-time activation of the service and ensure confidence in meeting genuine requirements. Due to the size of the marginally priced bid, we procured 151MW from 8 participants at prices ranging from £900/MWh to £1,200/MWh with an average price of £1,125/MWh.

Test 11 (01-03-2024) we set a requirement of 50MW in the within-day PM window, and we procured 56MW from 7 participants with prices ranging from £400/MWh to £750/MWh with an average price of £568/MWh.

Test 12 (02-03-2024) was the first time we conducted a test on a Saturday, we set a requirement of 100MW and issued a within-day AM window to accommodate potential issues with bid submission outside of office hours. We procured the full 100MW from 11 participants with prices ranging from £499/MWh to £1,000/MWh with an average price of £721/MWh. There was a reduction in the number of participants bidding in the weekend event, for test 10 we had 22 participants and 18 for test 12 on the Saturday.

Test 13 (14-03-2024) was conducted for a 50MW requirement in the Within-Day PM period. This test was a duplicate of test 11, as prices had consistently fallen with each volume reduction, prompting an investigation into the potential for lower pricing. During the test, 56MW was procured at prices ranging from £150/MWh to £735/MWh with an average price of £609/MWh. These results broadly align with test 11, however one provider submitted a bid of 1MW at £150/MWh which is the lowest price observed so far. We understand that some unsuccessful providers opted to still run their own delivery and self-fund this to their customers at their own expense.

Our final test 14 (21-03-2024) set a 75MW requirement in the Within-Day PM period but for non-consecutive Settlement periods (SP) SP36-17:30 to 18:00 and SP38-18:30 to 19:00. This was the first test to include a gap between requirement periods. Previously, requirements for 50MW and 100MW had been tested, but not a 75MW requirement. It was observed before Christmas that delivery for a second consecutive settlement period was consistent with the first period, but it hadn't been tested for non-consecutive settlement periods. For the SP36-17:30 to 18:00 service window, 80MW was procured at prices ranging from £425/MWh to £735/MWh with an average price of £688/MWh. For the SP38-18:30 to 19:00 service window, 84MW was procured at prices ranging from £425/MWh to £750/MWh with an average price of £659/MWh.

Delivery Date	Tests	From	Despatch Time	Procured MW	Delivered MW	Variation %	Payment
02/02/2024	8	17:00	within-day 1	157	227.8	45.1	£210,284
02/02/2024		17:30	within-day 1	161	246.1	52.9	£226,132
08/02/2024	9	18:00	within-day 2	179	190.6	6.5	£143,266
08/02/2024		18:30	within-day 2	178	186.7	4.9	£140,356
29/02/2024	10	18:00	within-day 2	151	129.1	-14.5	£73,863
01/03/2024	11	18:00	within-day 2	56	52.2	-6.8	£15,277
02/03/2024	12	18:00	within-day 1	100	129.4	29.4	£40,262
14/03/2024	13	18:00	within-day 2	56	59.1	5.5	£17,850
21/03/2024	14	17:30	within-day 2	80	70.8	-11.5	£24,364
21/03/2024		18:30	within-day 2	84	73.3	-12.7	£25,812

Table 8 - Tests with GAP = £0/MWh (Competitive Phase)

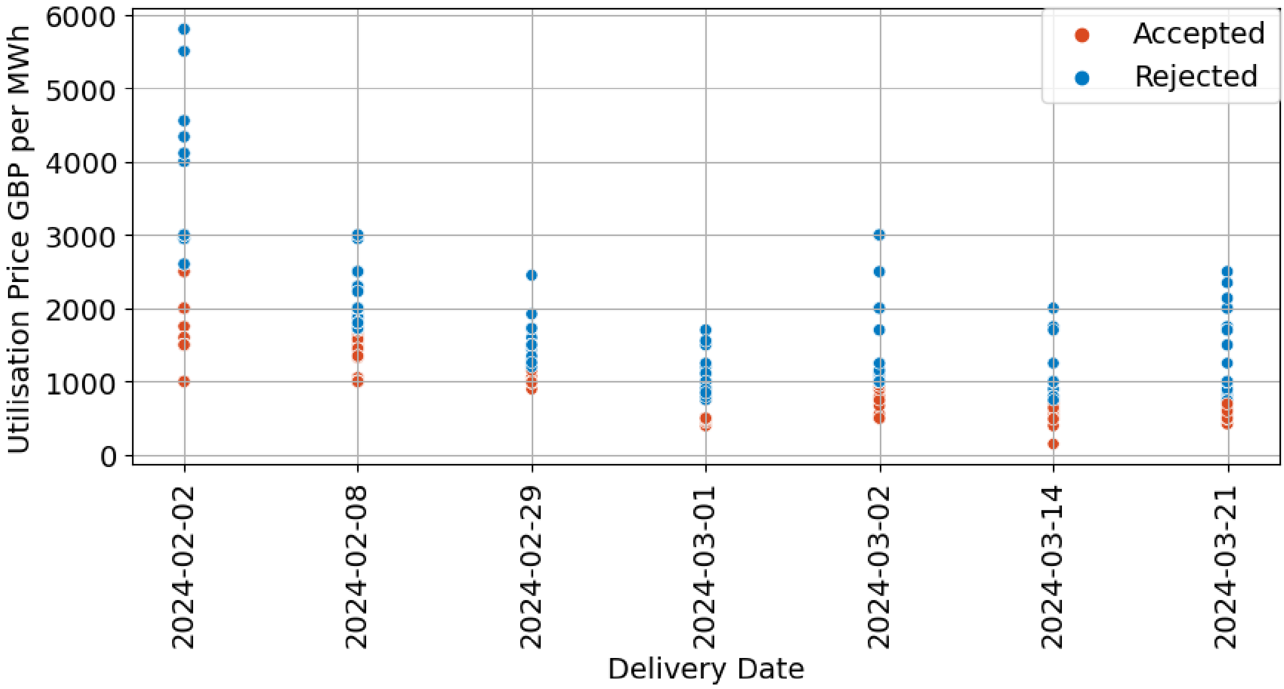

Figure 2 - Overview of submitted prices for competitive tests, showing the spread of utilisation prices submitted by participants.

Operational Insights

Operationally, uncertainty in delivery increases the risk that not all the procured MW will appear, and further actions will be necessary. This could increase the volume procured (to cover for this risk) which increases costs. Increased certainty therefore allows the ESO to have greater confidence that instructing the required volume will result in the required delivery. It is also important in real time, as the control room must be able to manage the real-time step change in demand, an unexpected variation of the order of 300MW carries risk of the system frequency going outside of operational limits, increasing risk (and cost of mitigation) of real time operation. Operating these tests gave ESO a controlled environment to learn and understand how this type of flexibility responds at varying procurement windows and how price correlates to delivery accuracy.

Delivered & procured quantities for each DFS unit and despatch times

Figure 3 shows Delivered and Procured quantities for each DFS Unit and contracted period event this winter, coloured by despatch time. Points on the line indicate occurrences where the delivered and procured volumes were equal for a unit. We notice how the points cluster roughly into two groups, depending on the procured quantity: those with DFS Units below 40 MW and those with DFS Units above 60 MW. In general, DFS Units above 60 MW exhibited larger variation with respect to the procured values, regardless of the despatch time. In contrast, the smaller units seem to be, on average, more accurate in their delivery against the procured quantities. This is somewhat counterintuitive in the sense that it is considerably easier to predict the aggregate behaviour of large groups of consumers than it is to predict the behaviour of a few. This aids to justify the selected maximum unit size of 100 MW from the point of view of limiting the potential larger variation that would be expected from even larger units and ultimately create challenges in the control room as outlined above.

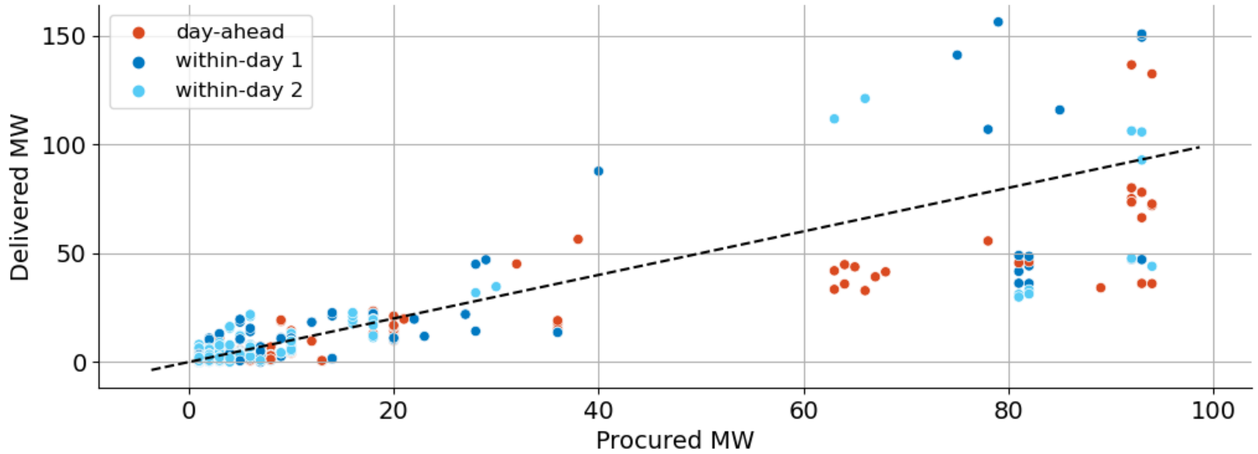

Figure 3 - DFS Procured and Delivered for each DFS Unit and contracted period by despatch time

Figure 4 shows the variation in MW and in percentage for each event. The bar represents the MW variation and the line represents the percentage variation. The initial aspect we notice from the figure is that the variation tended to become smaller as tests progressed. Indeed, the average variation from the first five events was about -150 MW whereas for the rest of the events was around 13 MW. This highlights that, on average, participants were able to take the initial events as learning points to improve their delivery expectation for subsequent tests. These resulted in ESO and specifically Control Room, being more confident in that delivered quantities will closely match procured quantities.

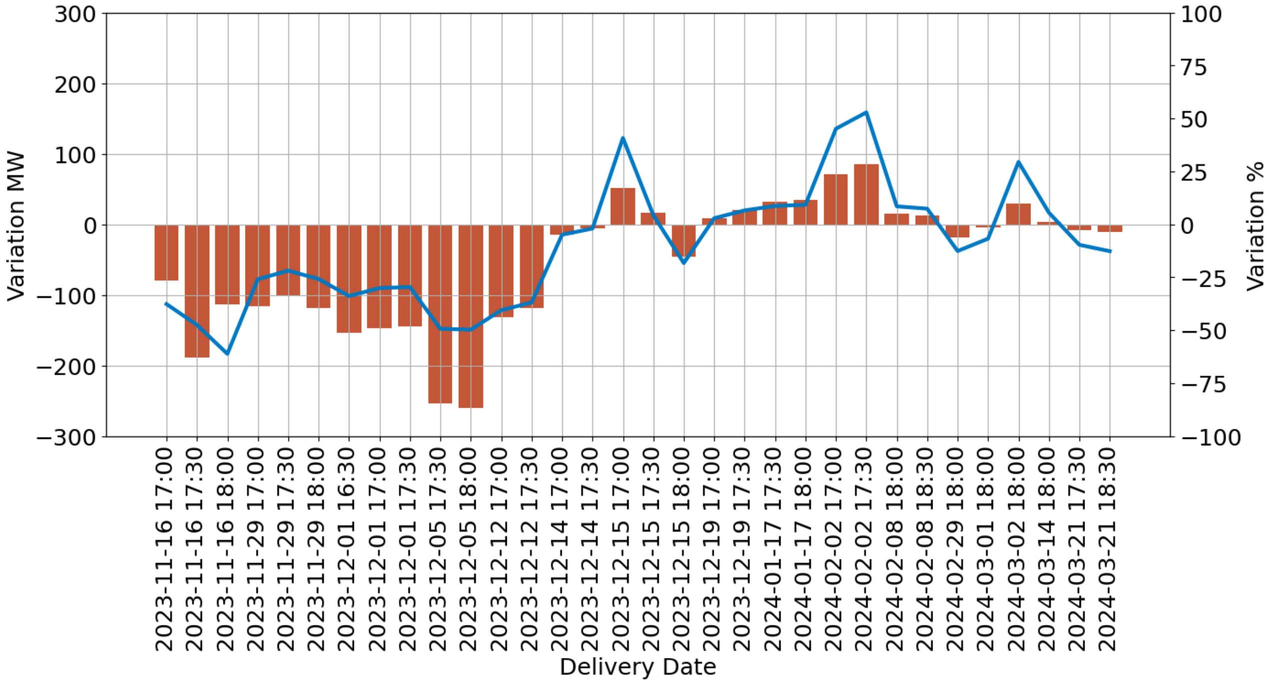

Figure 4 - Variation in delivery for each event, in MW and in percentage with respect to the procured quantities.

The variation in MW for each DFS Unit and contracted period is shown in Figure 5, coloured by despatch type. Overall, most units tended to exhibit small variations e.g., between -50 MW and +50 MW.

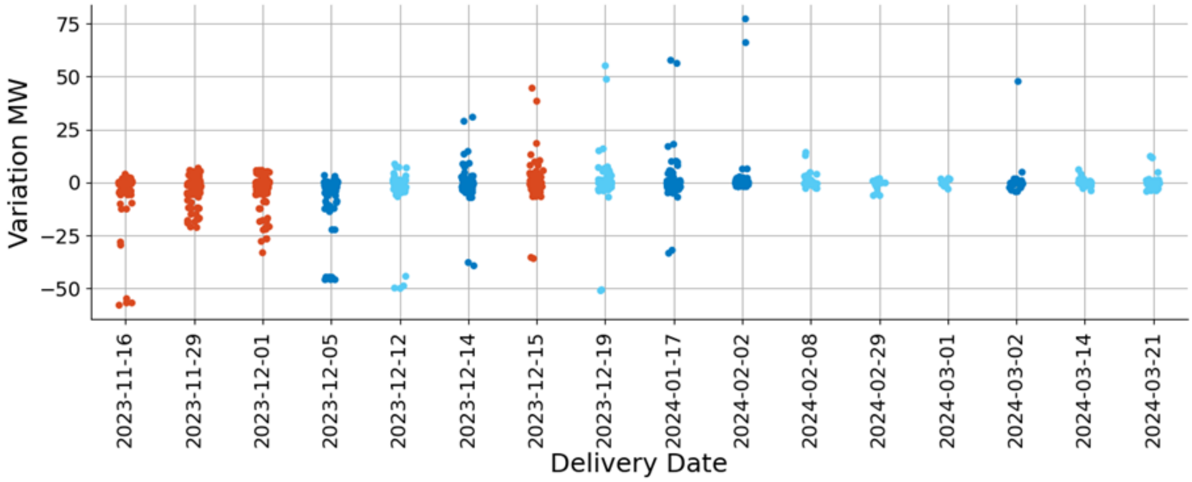

Figure 5 - Variation for each DFS Unit and contracted period.

Figure 6 shows the percentage variation across all events for winter 23/24. The bars represent the aggregated mean values for each event and the lines represent the spread of the variation from the underlying DFS Units. Specifically, the size of the line indicates the interquartile range (i.e., the middle 50%) for each event. For example, on the 15 December day-ahead test, the mean percentage variation was about +18% and half of the units exhibited a percentage variation between -60% and +40%. The other half of the units had variations either below -60% or above +40%.

Mean variation stayed within ±25% for all events except for the first within-day 1 activation, on December 5, 2023. The mean variation was negative for the first four events (including the two live events) and then it was positive for the first time from the test of December 12. The highest interquartile range was seen on the test of 2 March 2024. In this test, the spread of delivery from the accepted units was such that the middle 50% showed a variation between -60% to +60%. This highlights that, even as overall variation improved as the service progressed, it is challenging to predict delivery at the DFS Unit level. Indeed, even as mean variation reduced throughout winter, individual variations spread remained hard to predict.

The mean variation in percentage with respect to the procured quantity was -20% for DA, 4.3% for WD1 and -8.8% for WD2. Although most day-ahead tests took place early in the service, it is noteworthy that both the within day activations showed better accuracy when compared to day-ahead procurement. This is a key learning to help shape the future evolution of the service particularly from an operational standpoint.

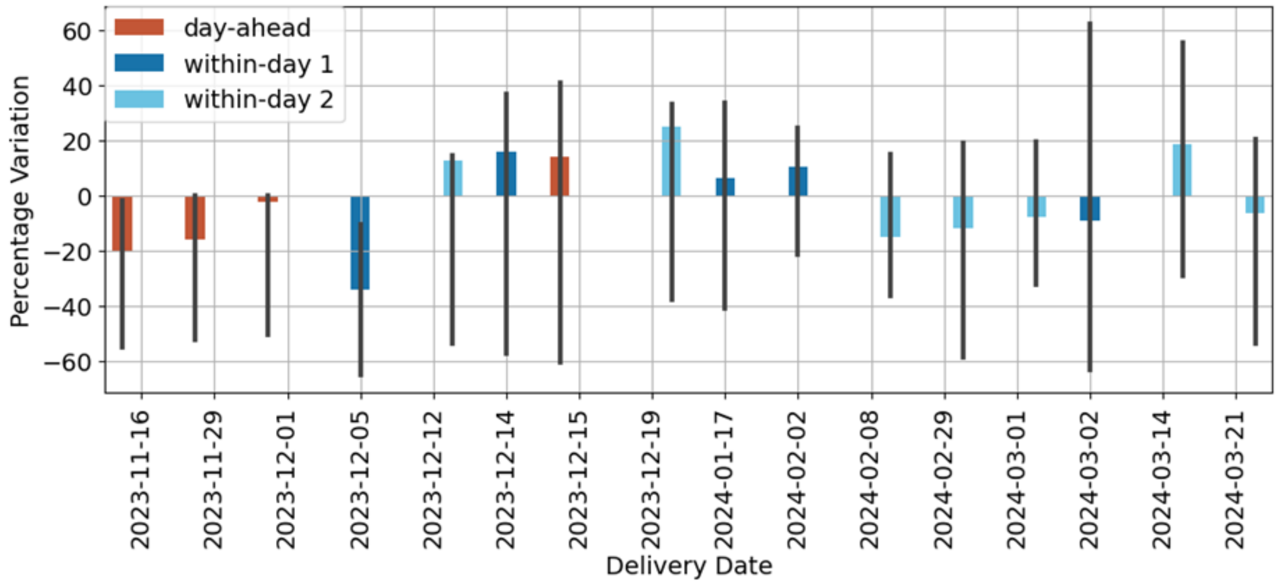

Figure 6 - Percentage variation across all events by Dispatch Type

The Table 9 below shows the share of delivered volume by consumer type. For the majority events (including the live activations), most of the delivery came from domestic end consumers. On average, delivery from domestic segment accounted for around 70% of delivery whereas the remaining share came from the I&C segment. The highest domestic share (90% of delivery) took place on 29 February 2024, delivering from 6 pm. It is worth noting that this event was called on the within-day 2 timescale. All throughout the March test, the share from domestic end consumers started to decrease, replaced by I&C. A possible reason for this is the competitive nature of tests in this period. Indeed, as the share is determined by those participants with accepted bids, and the competitive phase saw a reduced requirement, it is likely that accepting or rejecting a single participant had a larger effect on whether the resulting delivery came from domestic or I&C end consumers.

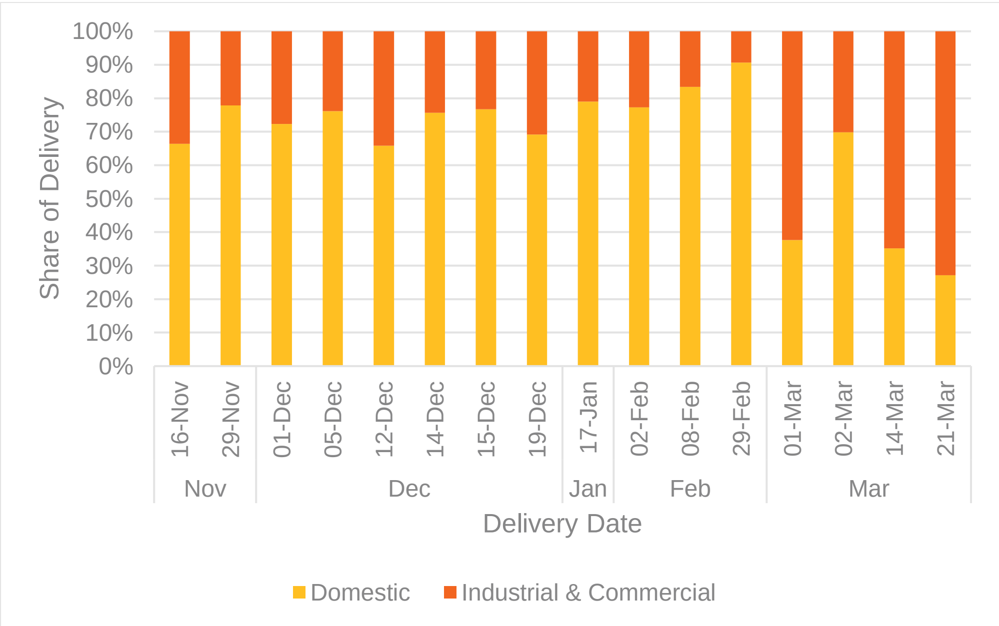

Table 9 – Delivery distribution by consumer and settlement type

In general, delivery from Domestic end-consumers represented most of the demand reduction achieved during winter 23/24. Figure 7a shows that the proportion of Domestic to I&C delivery remained somewhat consistent until we entered the competitive phase, and specifically from March 2024. Some large participants are overwhelmingly Domestic, and consequently, events where these participants are not accepted (e.g., because they are not competitive) will have a markedly different proportion of consumer type.

Figure 7b shows delivery breakdown by consumer type and settlement type. Notably, a negligible proportion, less than 1%, of I&C delivery is not HH settled. The delivery from HH settled consumers comes mainly from I&C customers.

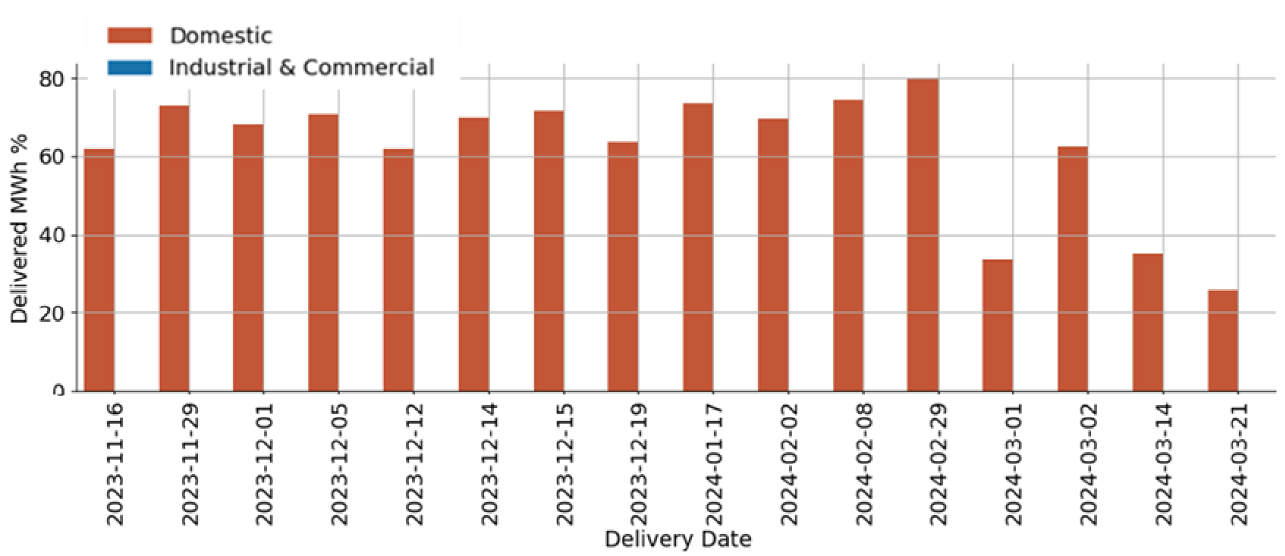

Figure 7a - Non HH Settled

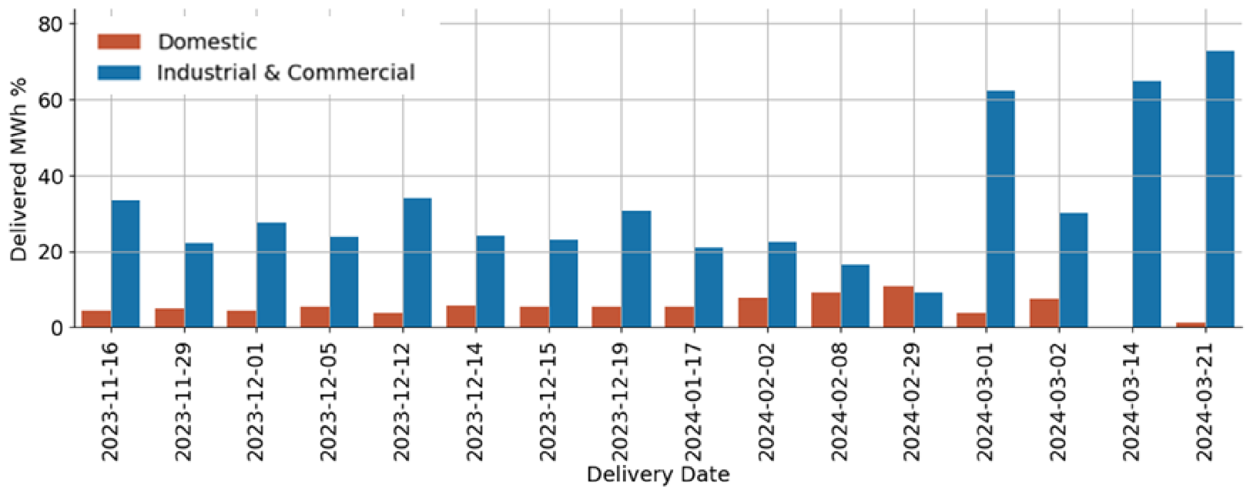

Figure 7b – HH Settled

Figure 8 shows peak forecasts for each procurement time (lines) with an overlay of how much was made available through bids on event days (markers). For perfect forecasts the markers would lie on the corresponding lines, but it can be seen that that is rarely the case indicating that the weekly forecasts presented challenges in their accuracy for planning purposes.

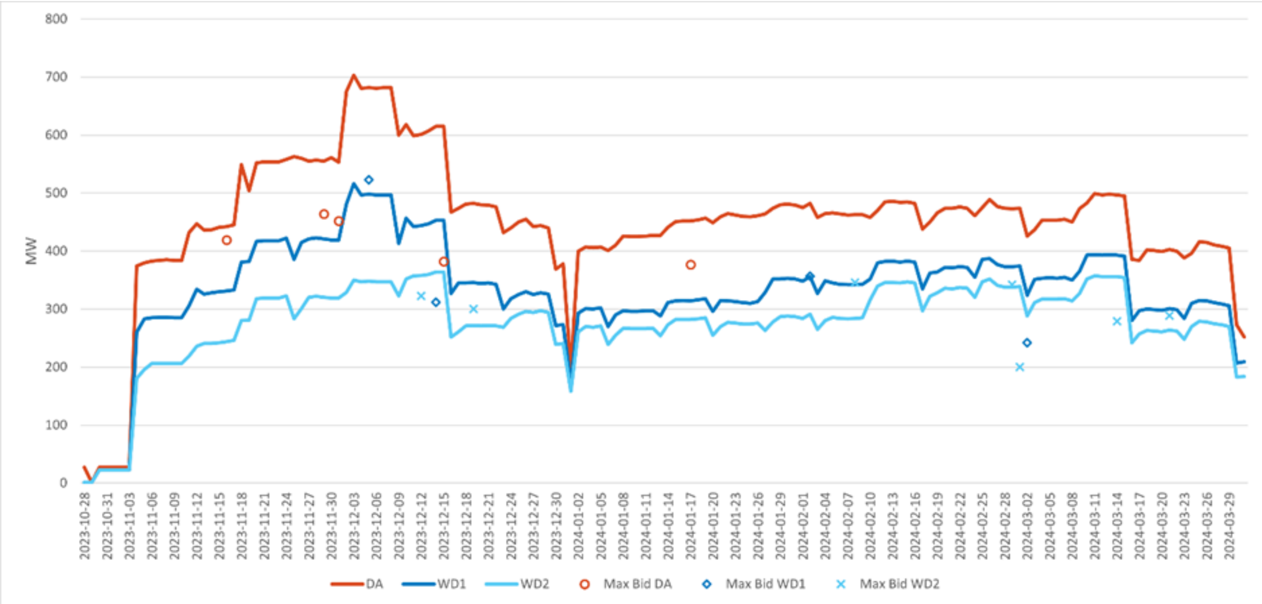

Figure 8

Delivery Breakdown

Domestic delivery originated from the aggregation of numerous small reductions. This can be observed by the proportion of delivery that comes from customers reducing 1 kW or less, which is presented in Table 9. On average, 91% of demand reduction from this segment was from reductions smaller or equal to 1 kW. Given the size of delivery an assumption can be made that 91% of domestic DFS delivery came from manual flexing/reducing actions as opposed to any significant level of EV/heat pump participation. This is insightful to show the level of uptake from a consumer psychology perspective to consciously engage in flexibility and take manual actions for the purpose of incentives.

Delivery from I&C customers was typically larger than those from domestic consumers which is as to be expected. On average, I&C reductions smaller than 1 kW accounted for 38% of the delivery from that segment. Around 35% of reductions were in the range between 1 and 10 kW and the rest, around 27% came from reductions exceeding 10 kW. I&C peak reduction from a single meter was 7.1 MW. Given the scale of I&C demand and previous TRIAD avoidance uptake it can be viewed that there is still significant opportunity for providers to grow this segment.

Delivery Date	Domestic			I&C		
	0 – 1 kW	1 – 10 kW	> 10 kW	0 – 1 kW	1 – 10 kW	> 10 kW
2023-11-16	92%	8%	0%	30%	36%	35%
2023-11-29	92%	8%	0%	38%	31%	31%
2023-12-01	93%	7%	0%	42%	29%	29%
2023-12-05	92%	8%	0%	42%	31%	27%
2023-12-12	90%	10%	0%	28%	42%	30%
2023-12-14	91%	9%	0%	33%	40%	27%
2023-12-15	90%	10%	0%	38%	37%	25%
2023-12-19	89%	11%	0%	31%	40%	28%
2024-01-17	90%	10%	0%	39%	34%	27%
2024-02-02	90%	10%	0%	45%	33%	22%
2024-02-08	90%	10%	0%	63%	18%	19%
2024-02-29	93%	7%	0%	52%	37%	10%
2024-03-01	93%	7%	0%	22%	31%	47%
2024-03-02	96%	4%	0%	47%	28%	25%
2024-03-14	81%	19%	0%	35%	44%	21%
2024-03-21	89%	11%	0%	30%	45%	25%

Table 10 – breakdown of delivery by quantity reduced for each event

Regional Breakdown

The breakdown of the monthly regional aggregated delivery is shown in Table 11. On average, the three regions with highest participation are East England, East Midlands and Southern England. North Scotland, South Wales and London are typically the regions with lowest share of the delivery. Delivery per region shows a correlation with regional subscription. That is, regions with more DFS meters subscribed tend to show a larger share of delivery for each event.

GSP Group	Nov 23'	Dec 23'	Jan 24'	Feb 24'	Mar 24'
East England	12%	13%	13%	14%	12%
East Midlands	12%	12%	11%	11%	12%
London	2%	2%	3%	3%	7%
Merseyside & Cheshire	6%	6%	5%	6%	7%
North East England	5%	4%	5%	5%	3%
North Scotland	1%	1%	1%	2%	1%
North West England	10%	9%	8%	9%	10%
South East England	8%	7%	8%	7%	6%
South Scotland	4%	4%	4%	4%	3%
South Wales	3%	3%	3%	3%	2%
South West England	6%	7%	7%	5%	5%
Southern England	11%	10%	12%	12%	12%
West Midlands	9%	9%	8%	9%	8%
Yorkshire	7%	8%	8%	7%	8%
Other	5%	5%	5%	5%	3%

Table 11 – Regional breakdown

Figure 9 shows a bar chart with the meter subscription share and delivery share per GSP Group. One might expect the bars to be of the same height, with each region's delivery proportional to their share of the meter subscription. However, it can be seen that a few regions e.g., Southern England, North West England and East Midlands, deliver far above what would be expected based on their meter subscription share. On the other hand, South Scotland, and South Wales both have delivery shares below expected based on meter subscription share.

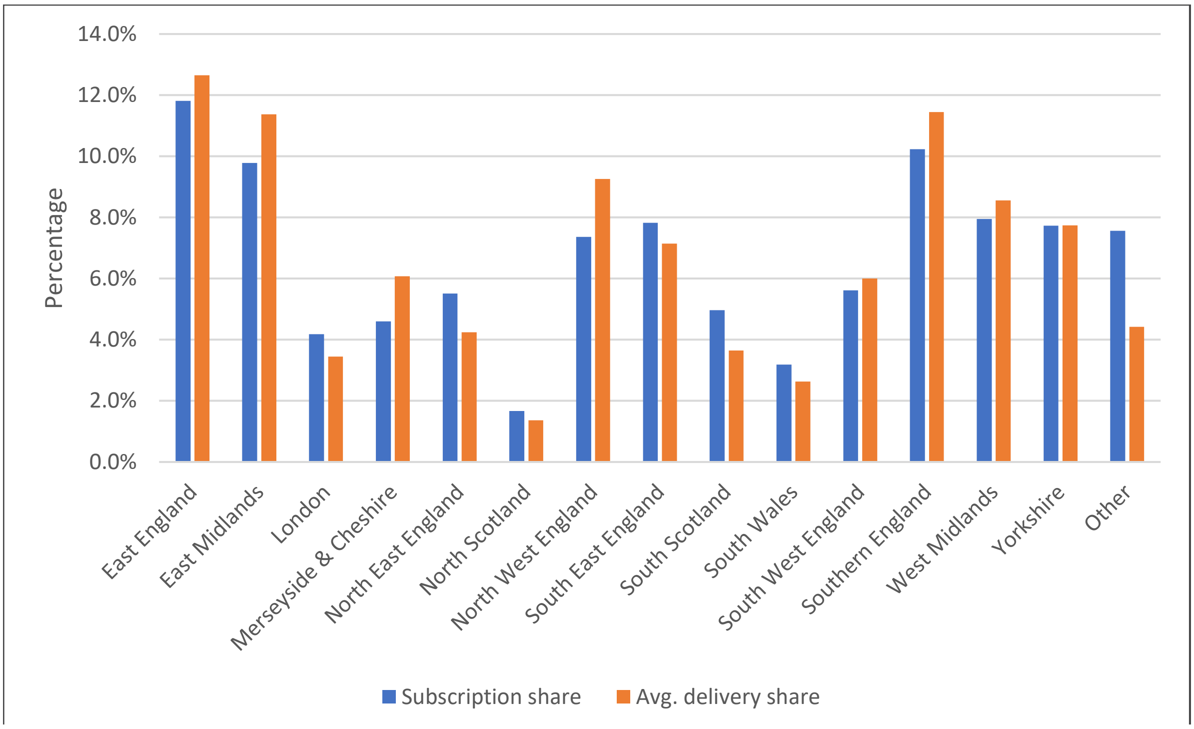

Figure 9 – Meter subscription and delivery share per GSP Group

5. Commerciality of DFS

DFS was designed as an enhanced action winter contingency tool as opposed to a BAU commercial product. However, it is still important to evaluate the commercial viability of DFS to understand if the benefits outweigh the costs. The following commercial analysis assesses a particular DFS test against the BM conditions that DFS was initially designed to be used for supporting, that being extremely tight margin days.

DFS saw a significant commercial improvement represented by Volume-Weighted Average Price (£/MWh). The most competitive use of DFS occurred on 01/03/2024 at 18:00, which was procured within day, and saw a Volume-Weighted Average Price of £585/MWh. However, some delivered volume, albeit small (<1 MWh) was procured as low as £150/MWh, showing the range of prices that may be possible in future iterations of the product with scaled efficiencies and improvements although we recognise the £150/MWh as an outlier.

Table 12 shows a selection of days that were used to compare alternative costs against DFS costs. These days have been selected to ensure that we are making a comparison against the type of conditions for which DFS was established to help support. It is worth noting that both winter and summer days feature in the table below outlining how an evolved product could benefit from supporting dispatch all year round.

#	Date-Time	Derated Margin (MW)	Reason for Selection
1	18/07/2022 18:30	-400	Identified tightest period. This was in the summer leading up to the first year of operation.
2	14/01/2022 15:00	-262	Chosen for the tightest day in winter, in 2022
3	12/06/2023 09:00	1,261	Selected as the tightest day in 2023, observed in summer
4	16/10/2023 18:00	2,260	Selected as the tightest days over the winter 23/24 period.
5	01/12/2023 18:00	2,790	
6	16/11/2023 17:00	2,956	

Table 12 – DFS days selected and alternative costs

To assess the cost-saving potential of DFS, we must assess how DFS would perform against tight margin days across many different scenarios. The tightest periods are from 2022 and are indicative of an energy supply crisis due to a year of low gas supply in Europe due to the Russia-Ukraine war, and low imports from Europe due to a combination of droughts affecting the hydro supply in the Nordics and significant outages and maintenance on the French nuclear fleet. The other days were selected primarily to show a range of tight days, from the year of energy supply difficulties (2022) as well as the most recent year where there was adequate energy supply, and to compare both summers and winters, as margins have been tight in both seasons which shows merit in the service being available all year round even in its current format.

The DFS result that was chosen as a competitive pricing comparison was from 21/03/2024 at 17:30, as the third-most competitive price, also as the most recent DFS price, to give a fair and balanced assessment of DFS against alternative Balancing Mechanism costs. For comparison, the most competitive price was procured on 01/03/2024 and was £585/MWh. The DFS comparison results are outlined in Table 13.

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DFS Comparison Results	
Date	21/03/2024 17:30
DFS Cost (£)	£24,364
DFS Capacity (MW)	70
DFS Volume (MWh)	35
DFS Price (£/MWh)	688.50

Table 13 Test Comparison Results

As can be seen in the Table 14 below, the DFS results at a price of £688.50/MWh would have saved up to £108,337.57 compared to the alternative costs in the BM on the 14/01/2022 at 15:00. Similarly, on 18/07/2022 18:30, DFS would have saved £40,780.32. These cost savings results are based on a 35 MWh procurement and delivery of DFS compared to the maximum Offer Price that was accepted on these days. Alternatively, in the four other comparison dates, DFS would have been a net cost if it had been used against the Maximum Offer Price that was accepted. There are large variances in the margin values between these events showing that on days where system conditions are not at their tightest and there is healthy liquidity in the BM DFS would not be the optimal product. We must be clear that DFS was not created to compete with such days and therefore this is a key consideration when reviewing the data.

It is important to note that this cost analysis is looking at the procurement of 35 MWh of DFS volume versus alternative sources from the BM. In a real scenario, it is likely that ESO would need to procure upwards of 400 MW / 200 MWh of reserve. Hence, one may expect the equivalent savings/costs under a real scenario to be multiplied by a factor of at least 5.

Cost/Savings Analysis						
Comparison Date	14/01/2022 15:00	18/07/2022 18:30	12/06/2023 09:00	16/10/2023 18:00	16/11/2023 17:00	01/12/2023 18:00
Margin (MW)	-261.78	-399.89	1,260.57	2,259.53	2,956.02	2,790.45
Maximum Offer Price Accepted (£/MWh)	3,750	1,841	207	400	259	269.4
BMU ID	SHBA-1	Northpool B_V_ .ING-NTPL1.LL	RATS-3	CNQPS-3	CNQPS-3	COSO-1
Fuel Type	CCGT	Interconnector	Coal	CCGT	CCGT	CCGT
Cost of Using Max. Offer Price for DFS Volume (£)	£132,701.25	£65,144.00	£7,325.11	£14,154.80	£7,389.87	£9,533.26
DFS Price Differential [+ means DFS is more expensive]	-£3,061.51	-£1,152.41	£481.49	£288.49	£479.66	£419.09
DFS Cost [Savings are negative]	-£108,337.57	-£40,780.32	£17,038.57	£10,208.88	£16,973.81	£14,830.42

Table 14 – Cost savings analysis

Understanding the commerciality of DFS can be simplified by reviewing when certain DFS price points would be more economical than the accepted prices of Offers for Margin in the BM. In Table 15 below, we have distributed the accepted offer prices for Margin against five observed DFS price points.

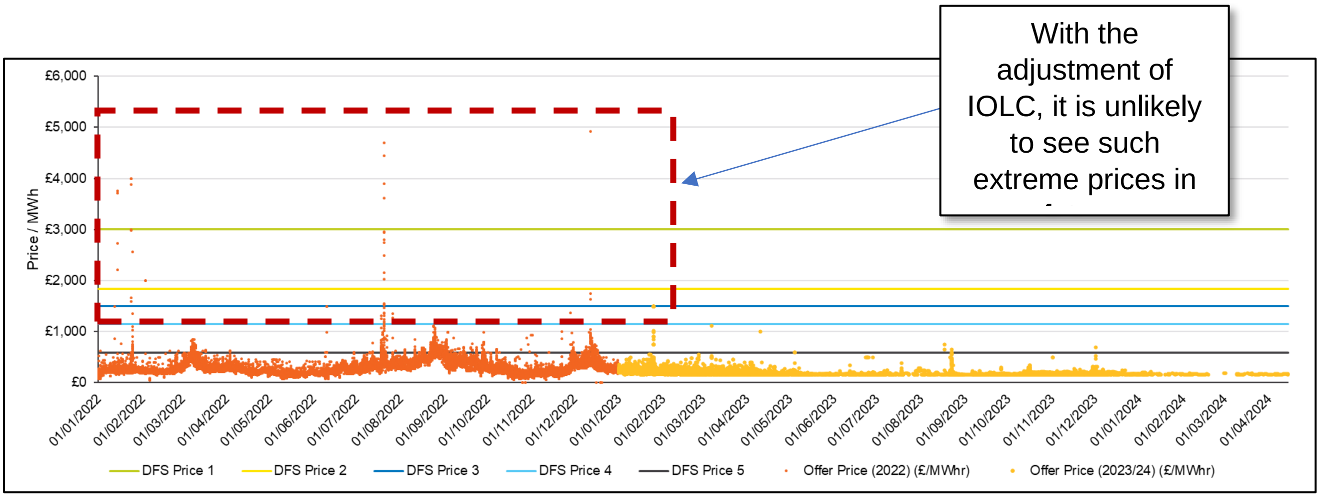

Table 15 - DFS Price points (1) £3,000/MWh (2) £1,846/MWh (3) £1,503/MWh (4) £1,145/MWh (5) £585/MWh

DFS Price 5 (£585/MWh) shows the most competitive test result and highlights the lower bounds of what is currently capable in terms of commerciality from DFS. As can be seen, DFS would have been a highly commercially viable product against certain offers throughout 2022 and early 2023. DFS was designed for extreme tight margin days and extreme price events, and 2022 was a year particularly prone to these events. Those instances of Offers taken above DFS Price point 5 indicate where DFS would have generated Balancing Costs savings.

It is important to note that the introduction of the Inflexible Offer Licence Condition (IOLC) has implemented conditions that prohibit generators from obtaining excessive benefit from offers in the Balancing Mechanism when their units are operated inflexibly in a manner that limits their responsiveness to market and system conditions. In addition to protecting consumers from the high balancing costs witnessed in recent years we anticipate that the IOLC will further encourage investment in new flexible production and demand side response. Thus, it is unlikely to see such extreme prices as those seen in 2022. However, should gas prices increase by 10-fold, for example, you may expect to see a similar increase in Margin Offer prices. What you would not expect, is a 5-fold increase in gas prices to result in a 10-fold increase in Margin Offer prices. Given DFS was designed to provide the equivalent of margin during these tight, expensive days, and given those tight, expensive days are likely to still occur in the future, we can expect DFS to provide value for those events in the future.

Even during 2023, where the IOLC was in place, and gas-prices have seen a significant reduction, we still see several instances where DFS would have been commercially viable to use against the BM Offers should the service have been positioned outside of an enhanced action service.

Given DFS was designed for extreme tight margin (and likely expensive days) DFS has also proved to be competitive against mild, and moderately expensive days in 2023, as well as significantly beneficial for use on extreme tight and expensive days in 2022. It is the conclusion of our analysis from winter 23/24 that DFS is a valuable tool for the control room to use when margins are tight, and alternative offer prices are dearer than that of DFS.

6. Operational

Due to the uncertainty that exists further away from real time, the closer to real time that the service can be dispatched in a live event, the lower the risk of contracting unnecessary volume. However, as the service was called for two live events, this effectively increased the margin on the system, reducing risk in those periods, although fortunately the system conditions did not worsen on those days such that our full reserve was utilised. This is not always the case, as on the day between the two live events, the 30 November, conditions did worsen approaching real time meaning that more reserve was utilised. As more wind generation was available on that day, the reserve requirement was able to be achieved through commercial means, but this does underline the importance of ensuring that the ESO takes the necessary actions to secure the reserve volume required to limit system risk.

Operationally, the volumes procured and delivered did not exceed a 500MW step change across half hourly boundaries, and therefore were within the typical variation seen at these times and so did not cause operational issues. There were occasions where this aligned with significant instantaneous and inflexible step-changes in the battery fleet Physical Notifications leading to increased risk management actions during these times (for example additional frequency response).

7. Consumer Evaluation

In July 2023 ESO published social research exploring how households participated in DFS winter 22/23 and their motivations and challenges. Work is currently underway to analyse smart meter data from the first year of DFS alongside our partners the Centre for Sustainable Energy (CSE) and ERM. A report and associated datasets will be published later in the year.

Further social research is planned for DFS winter 23/24 with CSE and ERM which will cover both households and business (Industrial & Commercial). We welcome the support from DFS providers in engaging with this work to maximise the value and learnings it realises.

Insights and data from winter 22/23 and 23/24 will be used to update the Consumer Building Blocks, which will be used by the ESO's Energy Insights and Analysis team as one of the tools to model how consumers may adapt their energy consumption in a range of different factors.

8. Industry Insights

ESO have continued to engage with industry throughout the winter and these discussions have helped support/shape some of the additional narrative outlined in this report.

DFS has broadly been recognised as supporting a step change in engaging consumers both domestic and commercial in flexibility especially where participation in more established markets is not currently possible. It engages ordinary consumers like households and SMEs and for the vast majority of MPAN's, this is their participation in flexibility markets and it's been a resoundingly positive experience. DFS also helps bridge the gap to Market-wide Half- Hourly Settlement by allowing non-Half hourly settled assets to flex their consumption. Others have commented that participation in DFS has been supported by the fact it receives great media attention and good PR which has a broader knock-on impact across industry and engagement around flexibility as a whole.

One of the biggest changes industry would like to see for future evolution, would be to allow stacking with other market services and this in turn, would increase volume. This was further supported in feedback obtained through the questionnaire.

As we approached the end of winter 23/24, we launched a DFS feedback questionnaire to seek input on learnings and priority areas, helping us shape an evolved service. We received a strong response which resulted in 38 responses in total and ESO conducted follow up calls & meetings to further explore these responses.

As part of the questionnaire, respondents categorised and identified topics in priority order of importance they would value further review when developing a future iteration of the service. The topic with higher priority on average by all respondents was a review of the overall revenue proposal, closely followed by allowing stacking with other market services. The graph below demonstrates the relative priority of different topics, according to the industry feedback.

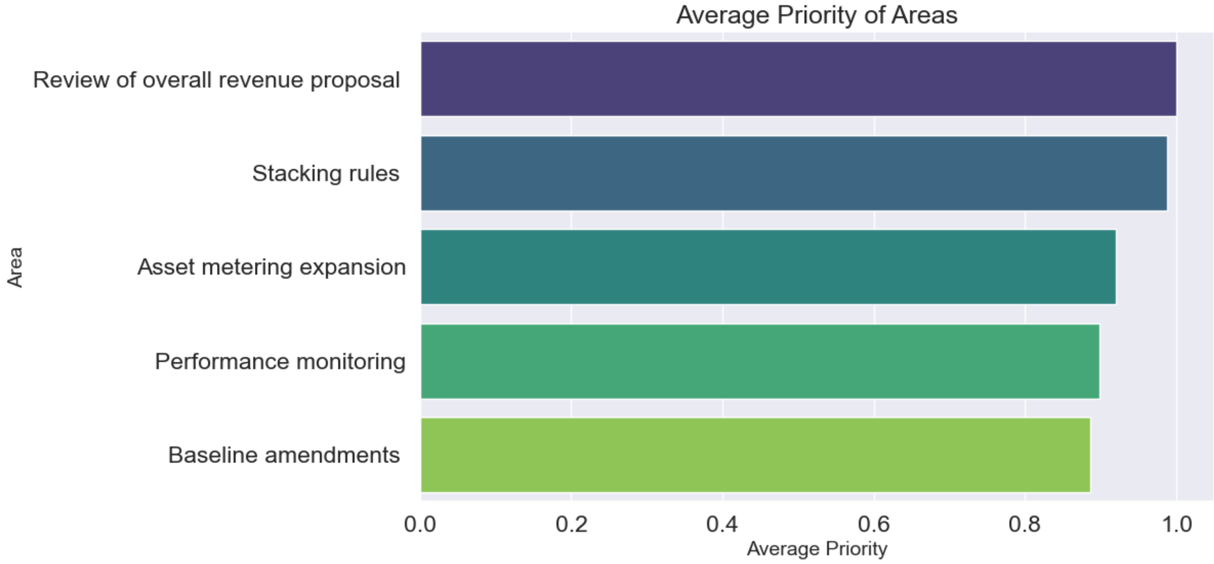

Table 16 – Feedback on Priority areas

ESO has also subsequently held sessions with our DNO partners to ensure we factor in their views and are able to support aligning activities. This engagement is helping us shape the future iteration of the service. As part of the above discussions ESO were also made aware of other broader industry topics/challenges that various providers encountered in growing their portfolios which we think are worth noting below.

- **Consumer Consent**
  Across the provider base different parties had different interpretations and approaches to their marketing and how any consumer consent challenges were overcome. Across the board most parties agreed they would welcome further clarity from government on these rules around positioning and evolving their offerings to consumers around consumer consent for marketing purposes. Whilst ESO did seek to provide some additional information on this topic in our communications principles we would welcome further clarity for market players as for some providers this meant there was considerable number of consumers who they were unable to approach for offering the DFS.

- **Boundary data access**
  Several providers cited the challenges around time and cost of accessing metering data if they were not the consumers electricity supplier. This was a consistent message across the aggregator community and as a result it appears that as services continue to expand and grow ensuring all parties can easily and efficiently access the right data assuming consumer consent is something that would value being improved.

9. Next Steps and the Evolution of DFS

The growth of DFS has significantly increased in winter 23/24 with more registered providers and participants. This demonstrates that large volumes of manually controlled flexibility can provide a reliable service to help manage energy balancing on the GB system. We foresee large scale manual flexibility will be best placed to be industry led through provider offerings and progress towards this will be highly dependent on the implementation of market wide half hourly settlement which we understand is currently targeted for 2027. In the meantime, the evolution of DFS will continue to act as a stepping stone and a home for this type of flexibility.

Our Flexibility Market Strategy team are currently shaping our mid-term ambitions and strategic priorities for flexibility as a whole and their final roadmaps which will be published later this year. You can find more information about that here and their call for input

We acknowledge that the circumstances and original need that drove the fast development and implementation of the DFS meant several difficult design decisions were taken to ensure we were able to move at pace and deliver an important winter contingency product. Our ambition is to continue to evolve and develop the product taking into account the valuable feedback we have had from industry. We know there are important themes such as stacking, value proposition and participation rules which parties want us to address. We continue to see strong levels of engagement which is encouraging for continuing to grow and maintain a route to market for this type of flexibility. We are mindful of the challenges raised from the regulator in the approval of the demand flexibility service and look forward to progressing these in an evolved version of the service. We have confirmed to industry we plan to carry out a European Balancing Regulation (EBR) Article 18 consultation for the evolution of the service going forward with an indicative timeline for this process below.

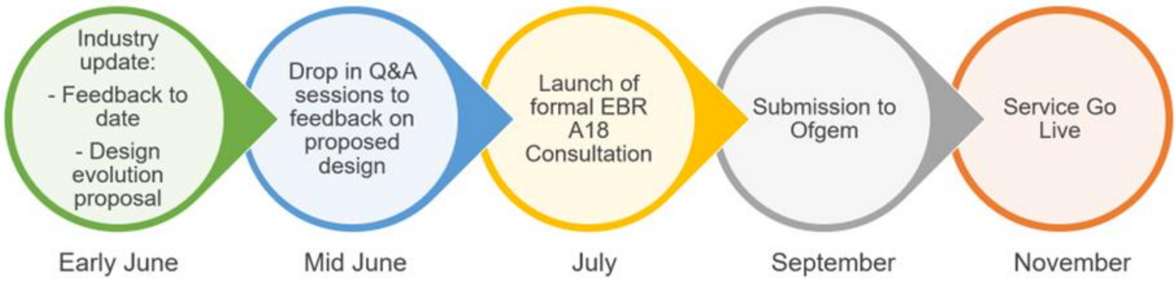

Figure 11 – Timeline

10. Appendix 1 – Contractual, Guidance & Reporting Documents

Service Terms 23/24 v2

Procurement Rules 23/24 v2

DFS Participation Guidance Document v11

Market Information Report Aug 23

Market Information Report Oct 23

Market Information Report Jan 24

Market Information Report Mar 24

Data Portal

11. Recognition