ESO RIIO2 Business Plan 2 (2023-25)

Q3 2023-24 Incentives Report

24 January 2024

Contents

Introduction

As part of the RIIO-2 price control, we submitted a second Business Plan to Ofgem in August 2022. It sets out our proposed activities, deliverables, and investments for years three and four of RIIO-2 (2023-2025) as we respond to the rapidly changing external environment.

The ESO's Delivery Schedule sets out in more detail what the ESO will deliver, along with associated milestones and outputs, for the "Business Plan 2" period.

Ofgem, as part of its Final Determinations for the RIIO-2 price control, set out that the ESO would be subject to an evaluative incentive framework, assessing our performance in delivering the Business Plan.

The updated ESO Reporting and Incentives (ESORI) guidance sets out the process and criteria for assessing the performance of the ESO, and the reporting requirements which form part of the incentive scheme for the BP2 period. Every month, we report on a set of monthly performance measures; Performance Metrics (which have benchmarks) and Regularly Reported Evidence items (which do not have benchmarks). This report is published on the 17th working day of each month, covering the preceding month.

Every quarter, we report on a larger set of performance measures, and also provide an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker. Our six-month and eighteen-month reports will broadly be similar to our usual quarterly report.

Our mid-scheme and end of scheme reports will be more detailed, covering all of the criteria used to assess our performance.

Following our Business Plan 2 (BP2) submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the BP2 DD&T investment portfolio. As per the ESORI guidance, we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

Please see our website for more information.

Summary of Notable Events

In December we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 12 December the Balancing Programme went live with Release 1 of the Open Balancing Platform (OBP). OBP, which is being delivered using agile methodology, and is set to replace our current balancing systems over the coming years. Further releases will happen throughout 2024 and we will continue to engage with industry on future developments and our delivery roadmap. You can view all our latest information here and sign up to receive future updates here.

- On 5 December we published that our Megawatt Dispatch broke exciting new ground. On 21 November, we carried out our first ever live dispatch of power that is being generated by a Distributed Energy Resource (DER) connected to the Distribution network and providing power into the main electricity transmission system. We were able to see the output reduce in real time for the first time.

- Following the frequency oscillations experienced over the summer the Network Control Programme have been working with one of our suppliers to get a new, real-time oscillation monitoring tool available to our Control Engineers. This new oscillation situational awareness tool solution is now available to Control Engineers and is being assessed to understand the accuracy and usability.

- In December 2023, we published our assessment and conclusions from Phase 4 of our Net Zero Market Reform (NZMR) programme with its conclusion on investment policies, including potential reform of the EMR schemes (i.e. Contracts for Difference and Capacity Market) and their packaging with wholesale market reforms.

- On 14 December, we held a webinar to update stakeholders on progress towards introducing early competition. This covered updates on the strategic position from government and the passing of the Energy Act 2023. We also set out our plans for working closely with Ofgem over the next year in order to launch the first competition during 2024.

- On 19 December we held a webinar to update industry on the current status of the Reserve Reform project. Reserve Reform had been delayed twice because of reprioritisation due to world events and system challenges. This webinar ran through the plan and new timelines for delivery of the new Reserve Services (Quick & Slow), we had over 100 attendees for the webinar with good feedback and questions on the content delivered.

- On 5 December, following a year-long process conducted with industry and wider stakeholders to identify the longer-term reforms needed to improve the connections process, we set out our final recommendations. Our new “First Ready, First Connected” approach, supports projects that can deliver at speed and ensures the connections queue can no longer be bogged down by so called “zombie projects”.

- On 19 December, we launched the invitation to tender (ITT) for the Voltage 2026 NSP tender. This Voltage 2026 tender will allow us to identify potential solutions to meet reactive power requirements in two regions in England from 2026 onwards, and represents the third Voltage “Pathfinder” type procurement that we have run.

- On 20 December, we launched the invitation to tender (ITT) for the first tender of the Mid-Term (Y-1) Stability Market, which is focused on securing stability services between 2025 and 2026. Earlier in 2023, we hosted a conclusion webinar about which brought the Stability Market Design innovation project to a close. During this webinar we also confirmed that we will start implementing the enduring Stability Market with the Mid-Term (Y-1) Market, which is focused on securing stability through one-year contracts, one-year prior to the point in time the service is required.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for Q3 2023-24.

Table 1: Summary of Metrics

Monthly (M) and Quarterly (Q) Metrics

Metric		Performance	Status				
			M / Q	Oct	Nov	Dec	Q3
Metric 1A	**Balancing Costs**	December: £240m vs benchmark of £299m	M	●	●	●	●
Metric 1B	**Demand Forecasting**	December: Forecasting error of 640MW vs indicative benchmark of 659MW	M	●	●	●	●
Metric 1C	**Wind Generation Forecasting**	December: Forecasting error of 5.61% vs indicative benchmark of 5.38%	M	●	●	●	●
Metric 1D	**Short Notice Changes to Planned Outages**	December: 2.5 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	M	●	●	●	●
Metric 2Ai	**Phase-out of non-competitive balancing services** (% of services procured competitively, calculated by volume)	Frequency Response & Reserve: 25% procured non-competitively in Q3 vs benchmark of 25%	Q	n/a	n/a	n/a	●
		Reactive Power: 97% procured non-competitively in Q3 vs benchmark of 90%	Q	n/a	n/a	n/a	●
		Constraints: N/A% procured non-competitively in Q3 vs benchmark of 65%	Q	n/a	n/a	n/a	**N/A**
Metric 2X	**Day-ahead procurement**	78% balancing services procured at no earlier than the day-ahead stage vs benchmark of 55%	Q	n/a	n/a	n/a	●

Below expectations ● **Meeting expectations** ● **Exceeding expectations** ●

Table 2: Summary of RREs

RREs don't have performance benchmarks (with the exception of 2C and 2D which are reported annually).

Monthly (M) and Quarterly (Q) RREs

RRE		Performance	M / Q
RRE 1E	**Transparency of Operational Decision Making**	December: 86.7% of actions taken in merit order	M
RRE 1F	**Zero Carbon Operability indicator**	Q3: Highest ZCO% of 91% after ESO operational actions	Q
RRE 1G	**Carbon intensity of ESO actions**	December: 8.9gCO_2/kWh of actions taken by the ESO	M
RRE 1H	**Constraints cost savings from collaboration with TOs**	Q3: £260m	Q
RRE 1I	**Security of Supply**	December: 1 instance where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	M
RRE 1J	**CNI Outages**	December: 0 planned and 0 unplanned system outages	M
RRE 2Aii	**Balancing services procured in a non-competitive manner**	Q3: £55.3m spend on non-competitive services. Volume of 17.8 TWH and 10 TVARH	Q
RRE 2B	**Diversity of service providers**	*See report for details*	Q
RRE 2E	**Accuracy of Forecasts for Charge Setting**	December: Month ahead BSUoS forecasting accuracy (absolute percentage error) of 1%	M
RRE 3X	**Connection Offers**	Q3: 501 connection offers made within 3 months, one taking longer than 3 months. TEC queue stands at 458 GW.	Q
RRE 3Y	**Percentage of 'right first time' connection offers**	Q3: 95% of connections offers were right first time	Q

We welcome feedback on our performance reporting to box.soincentives.electricity@nationalgrideso.com

Adelle Wainwright

Acting ESO Regulation Senior Manager

Metric 1A Balancing cost management

This metric measures the ESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark has been introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark has been derived using the historical relationships between those two drivers and balancing costs:

i. The benchmark was created using monthly data from the preceding 3 years.

ii. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.

iii. A straight-line relationship established between historic non-constraint costs and the historic wholesale day ahead price of electricity.

iv. Ex-post actual data inputted into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used are as follows (with Day Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 54.48 + (Day Ahead baseload x 0.52)
Constraint costs = -32.66 + (Day Ahead baseload x 0.34) + (Outturn wind x 25.72)

Benchmark (Total) = 21.82 + (Day Ahead baseload x 0.86) + (Outturn wind x 25.72)

**Constants in the formulas above are derived from the benchmark model*

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

December 2023-24 performance

Figure 1: 2023-24 Monthly balancing cost outturn versus benchmark

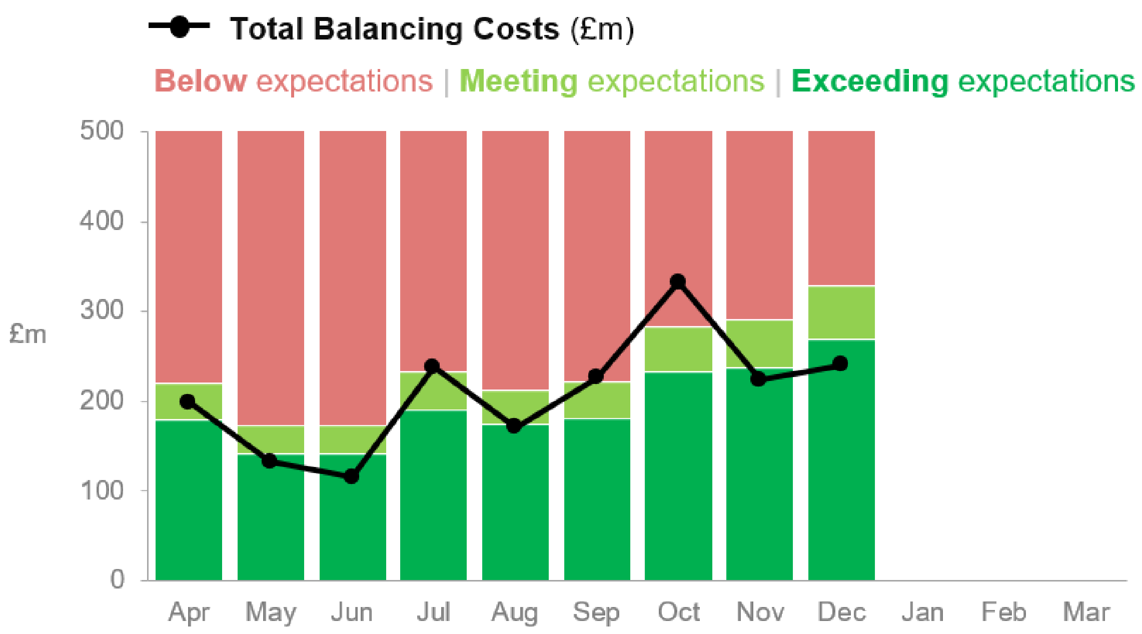


Table 3: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4	4.6	3.8	4.2	6.2	6.1	8.3				41.58
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86	83	89	99	74				n/a
Benchmark	200	157	158	212	194	201	258	264	299				1942
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**	**226**	332	224	240				**1877**
Status	●	●	●	●	●	●	●	●	●				●

Previous months' outturn balancing costs are updated every month with reconciled values. Figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place.

Performance benchmarks:

- **Exceeding expectations:** 10% lower than the annual balancing cost benchmark
- **Meeting expectations:** within ±10% of the annual balancing cost benchmark
- **Below expectations:** 10% higher than the annual balancing cost benchmark

Supporting information

ℹ	**Ongoing data issue:**	Please note that due to a data issue, over the previous months the Minor Components line in Non-Constraint Costs is capturing some costs which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to the Operating Reserve Category. Although the categorisation of costs is not correct, we are confident that the total costs are correct in all months. We continue to investigate and will advise when we have a resolution.

This month's benchmark

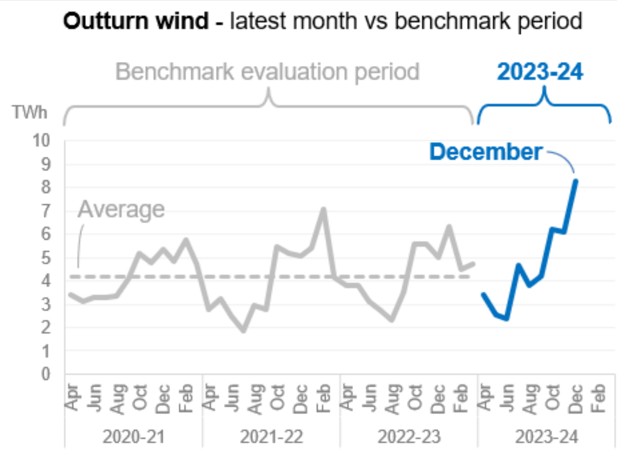
As noted in the introduction to this section, a new benchmark was introduced for BP2. The benchmark is derived using the historical relationships between two drivers (wholesale price and outturn wind generation) and balancing costs.

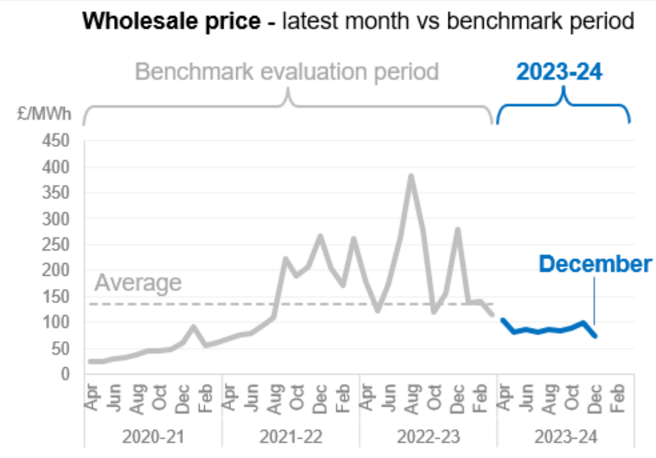
The December benchmark of £299m is the highest so far in 2023-24, and this reflects:

- an **outturn wind** figure significantly higher compared to last month and to the benchmark evaluation period (the last three years). In the entire benchmark period, there is no month that has had higher outturn wind than this.

- a drop of £25 per MWh in the average monthly **wholesale price** (Day Ahead Baseload) this month compared to November 2023, which takes it to the lowest it's been so far in 2023-24. It remains relatively low compared to the benchmark evaluation period (the last three years). Despite the drop this month, the big increase in the overall benchmark reflects the impact of the record levels of wind generation.

[1] Outturn balancing costs excludes Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.





December performance

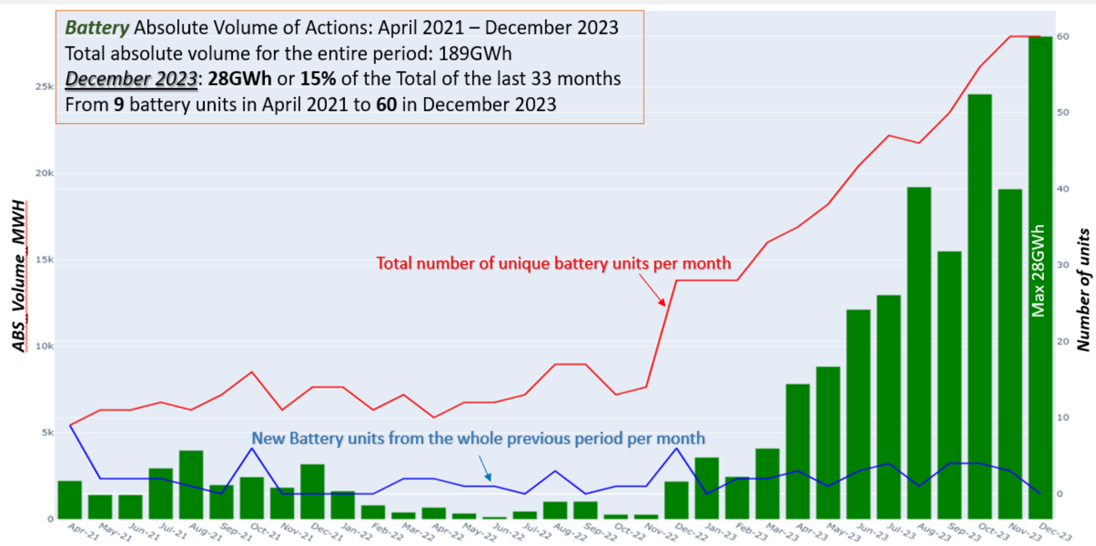
December's total balancing costs were £240m which is £59m (~20%) below the benchmark of £299m, and therefore performance is exceeding expectations. This is the second consecutive month and fourth time that the ESO has 'exceeded expectations' since April 2023, despite high-cost conditions for Dec-23. December's overall outturn wind was the highest ever, significantly above November's and October's outturn. However, the volume weighted average price for bids and offers significantly dropped compared to the last two months, following the downward trajectory of the energy prices.

Also, the first stage of our new platform to support the bulk dispatch of battery storage and small Balancing Mechanism Units, the Open Balancing Platform (OBP), went live on 12 December. December also had the highest battery dispatch volume (28GWh) since April 2021 as show on the graph below. This illustrates our commitment to maximising the flexibility of energy offered by battery storage over the last year.

As the graph illustrates, we have been focussed on increasing the utilisation of storage assets. We hosted an event in London in October whereby we listened and worked with industry to understand how their storage assets can be more efficiently utilised to assist system balancing. We appointed a full-time Battery Storage Product Lead to continue this technical engagement and to implement the necessary changes in the Control Room.

The capability of dispatching batteries in the Control Room has since then improved. An example of this is the VERGIL tool which has been updated to dispatch batteries over much faster timescales. Control Engineer roles have also been reviewed to focus more on efficient storage dispatch. This work was followed by the release of Open Balancing Platform phase 1 in December this year which has enabled 'Bulk Dispatch', a new tool that means control room engineers can send hundreds of instructions to smaller Balancing Mechanism Units and battery storage units at the press of a button.

April 21 to December 23 - Monthly Volume of actions for Batteries and number of unique units



Despite high-cost conditions for Dec-23 – with record wind generation, and greater constraint volumes compared to November, particularly in Scotland, which saw an increase in actions by 65GWh, the constraint cost in this region decreased by £5.8m. We were able to make a significant amount of savings through optimising outages and trading activities.

The total savings from outage optimisation were £43.5m. Approximately £25m was saved through just one specific action by the Outage Optimisation team requesting that two outages be taken together to increase the SPANSIZEX boundary by 800 MW.

The Trading team were also able to make significant savings through commercial decisions with interconnectors. A total of £45m was saved by taking these actions compared to alternative BM actions.

It is also important to note that the premier implementation of OBP in December 2023 saw the greatest volume of Battery Balancing Actions since market start (28GWh; or 15% of total Battery actions over the last 33 months). The greater efficiency of battery dispatch opens the opportunity for better decision making in the control room, and cheaper, but smaller units being used for balancing. Engagement with the team has begun to quantify savings.

One reason contributing to an increase in constraint costs compared to November 2023 is short notice downrating of lines by GB Transmission Owners, which has been occurring frequently throughout December. One of the actions we take to manage this is to curtail generation to manage the lower line ratings. One incidence of this occurred on 20 to 28 December where an additional number of bids were taken on wind units to manage the SSHARN7 constraint. A more detailed assessment of the cost impact of these down ratings is being carried out.

Breakdown of costs vs previous month

Balancing Costs variance (£m): December 2023 vs November 2023

		(a) Nov-23	(b) Dec-23	(b) - (a) Variance	decrease ◀ ▶ increase Variance chart
Non-Constraint Costs	Energy Imbalance	5.1	5.0	(0.2)	
	Operating Reserve	23.6	27.7	4.1	
	STOR	4.5	9.5	5.0	
	Negative Reserve	1.0	1.8	0.8	
	Fast Reserve	14.8	13.3	(1.5)	
	Response	18.3	15.8	(2.5)	
	Other Reserve	1.6	2.4	0.8	
	Reactive	15.2	16.1	0.9	
	Restoration	2.9	4.4	1.5	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	12.5	9.0	(3.6)	
Constraint Costs	Constraints - E&W	33.0	50.3	17.3	
	Constraints - Cheviot	3.7	0.1	(3.7)	
	Constraints - Scotland	54.4	48.5	(5.8)	
	Constraints - Ancillary	0.2	0.2	0.0	
	ROCOF	6.6	5.4	(1.2)	
	Constraints Sterilised HR	29.2	31.2	2.0	
Totals	Non-Constraint Costs - TOTAL	99.4	104.7	5.4	
	Constraint Costs - TOTAL	127.1	135.6	8.6	
	Total Balancing Costs	**226.4**	**240.4**	**13.9**	

As shown in the total rows from the table above, both non-constraint & constraint costs increased by £5.4m & £8.6m respectively, resulting in an overall increase of £13.9m compared to November 2023.

Constraint costs: The main driver of the variances this month are detailed below:

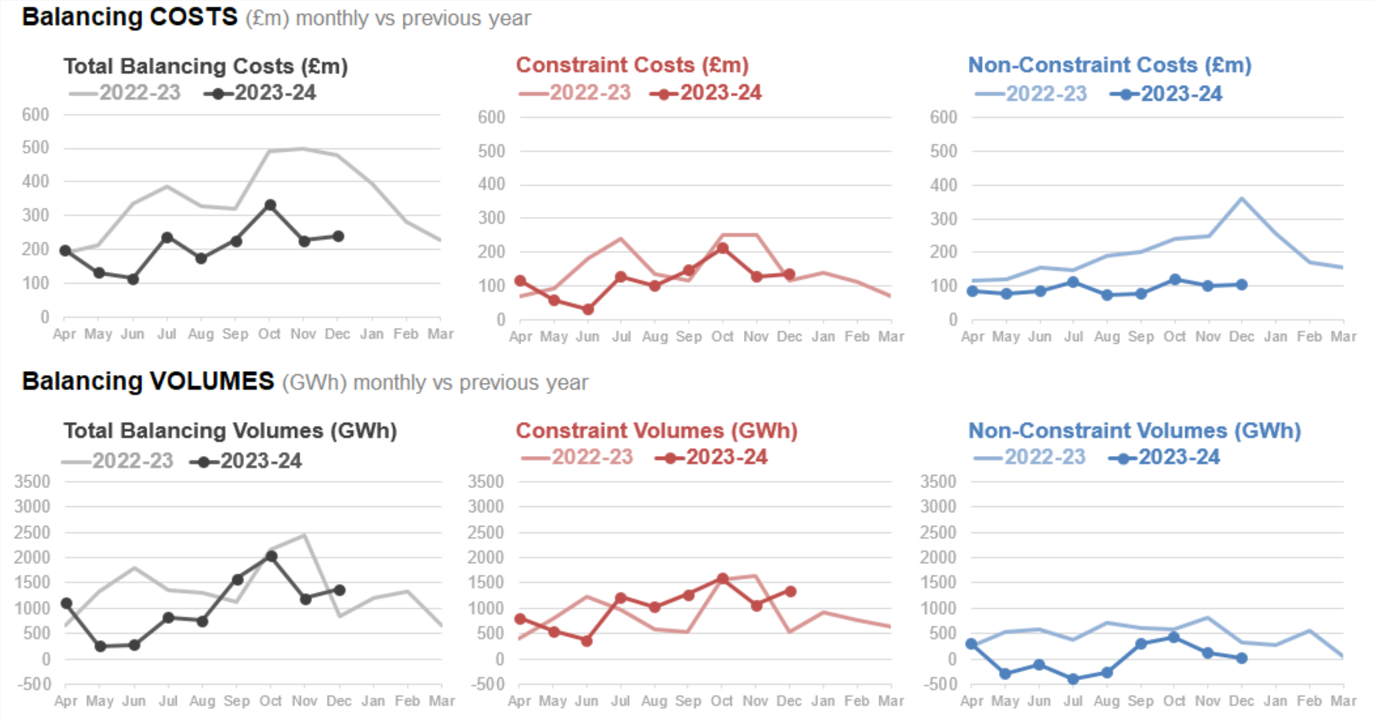
- **Constraint-Scotland & Cheviot***: Although the volume of actions increased by ~65GWh, the constraint cost decreased by £5.8m.
- **Constraint-England & Wales***: Despite the drop in volume of the total actions (~23GWh) the constraint cost increased by £17.3m, mainly due to an increase in the import constraint actions by~120GWh for voltage control and to support system inertia.
- **Constraints Sterilised Headroom***: £2m slight increase, even though the total volume of replacement energy significantly increased by ~300GWh.

*278 fewer planned outages compared to last month, which tends to be the case during the winter months, and a significant decrease of the volume weighted average price for bids and offers following the downward trajectory of electricity prices of the month. Outage volumes tend to decrease over the Winter months in preparation for peak demand conditions.

Non-constraint costs: The main driver of the biggest difference this month is:

- **STOR**: £5m increase, but at the time of writing this report the volume of actions from ancillary services are not yet quantified.
- **Operating Reserve**: £4.1m increase due to 61GWh more reserve required to secure the system.

Constraint vs non-constraint costs and volumes



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is mainly Operating Reserve cost and volume. The broad themes describing this cost are featured below. The figures will be revised once the data issue is resolved.

Constraint costs

Compared with the same month of the previous year:	Constraint costs were £17.6m higher than in December 2022, because the volume of constraint actions increased by 515GWh.
Compared with last month:	Constraint costs were £8.6m higher than in November 2023, due to higher volume of constraint actions by 262GWh, driven by significantly higher outturn wind.

Non-constraint costs**

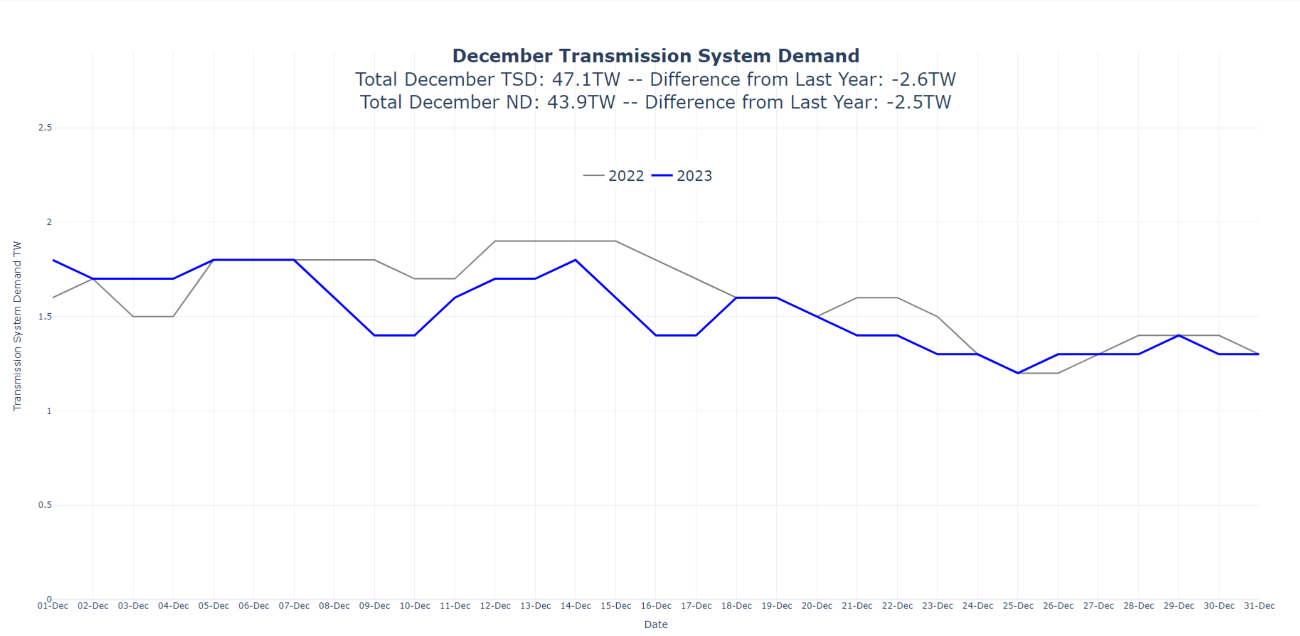
Compared with the same month of the previous year:	Non-Constraint costs were £256m lower than in December 2022 due to: • Significantly lower average wholesale prices* • 287 GWh lower Volume of actions
Compared with last month:	Non-Constraint costs were £5.4m higher than in November 2023 due to over 231 GWh absolute volume of actions were required to balance the system.

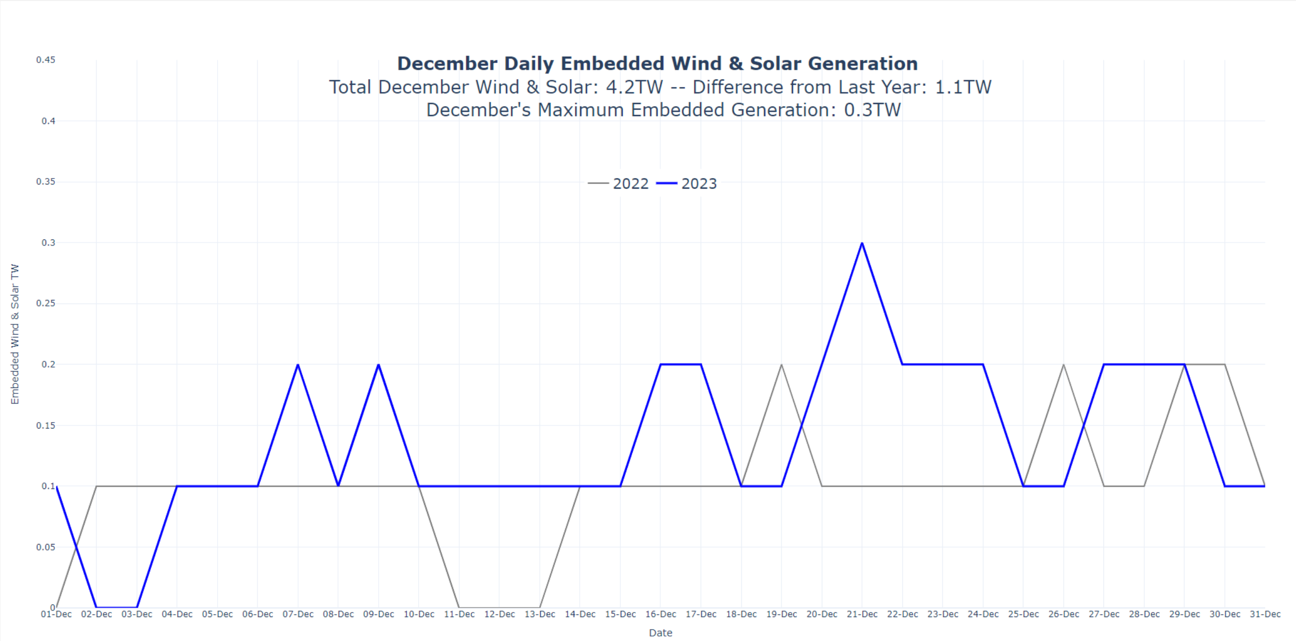
***** Average wholesale price for December 23: £74/MWh compared to £280/MWh for December 22.

** The non-constraint category consists of several subcategories including energy imbalance, response, reserve, and restoration

December daily Transmission System Demand (TSD*), Embedded Wind and Solar Generation

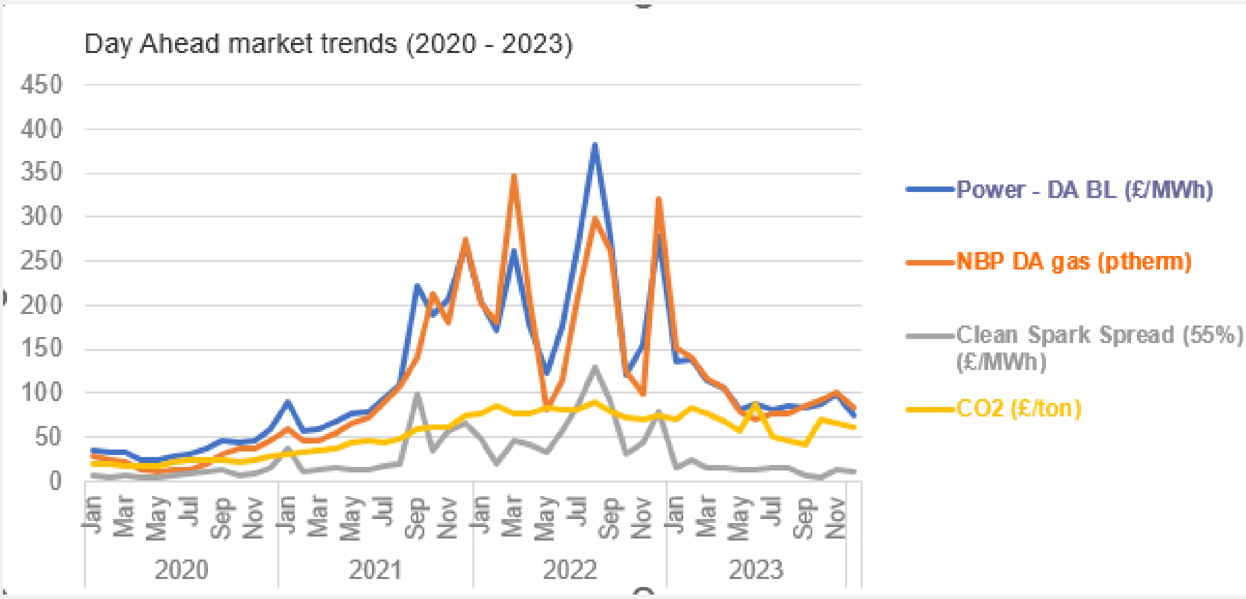
- **National Demand** (not shown below) was 2.5TW lower than the same period last year
- **Transmission System Demand*** was 2.6TW lower than December 2022.
- **Embedded wind & solar generation** was 1.1TW higher than the corresponding period last year. The maximum embedded wind & solar generation occurred on December 21st (0.3TW).





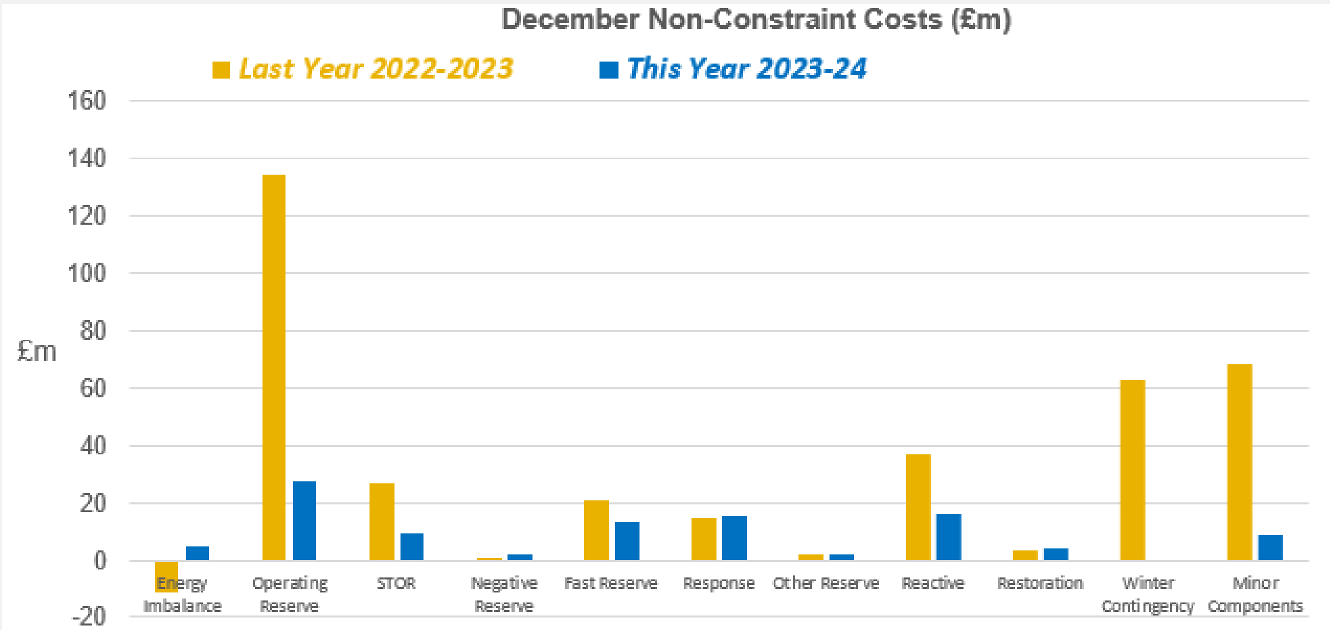
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand includes an estimate of station load of 500MW in BST (British Summer Time) and 600MW in GMT (Greenwich Mean Time).

Changes in energy balancing costs



DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

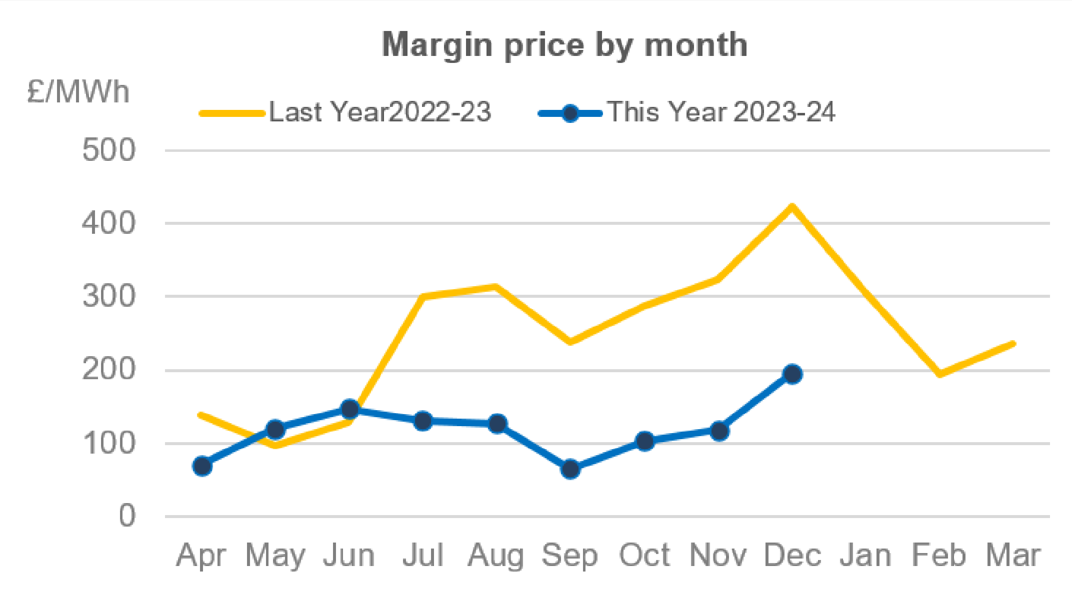
All the trends had a downward trajectory compared to last month. They all remain lower compared to the previous year.



Comparing the non-constraint costs of December 2023 with those of December 2022, most categories showed a decrease or a small deviation:

- **Energy Imbalance** £16m increase due to ~133GWh more volume of actions taken to balance the system.
- **Operating Reserve** £106.7m decrease mainly due to the significant downward trajectory we have observed in all the energy related prices.
- **Reactive** £20.7m decrease, due to a significant drop in the weighted average price, from £12 per MVAR to £5 per MVAR.
- **Minor Components** decreased by £59.7m. Last year's excessive cost contained incorrectly allocated cost from operating reserve that we have identified in the last end of the year report.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for one MWh) have increased compared to November 2023, but it is significantly lower than the corresponding period of the previous year.

Daily Costs Trends

Although as stated above, December's balancing costs were £13.9m higher than the previous month, none of the days were recorded with costs above £15m. However, around the 30% of days had a daily total cost over £10m, resulting in an increase by £0.3m the average monthly daily cost (from £7.5m to £7.8m).

The highest total cost observed on 22 December when the total spend was £13.3m, constraints were the major cost component driven by high renewable generation. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs.

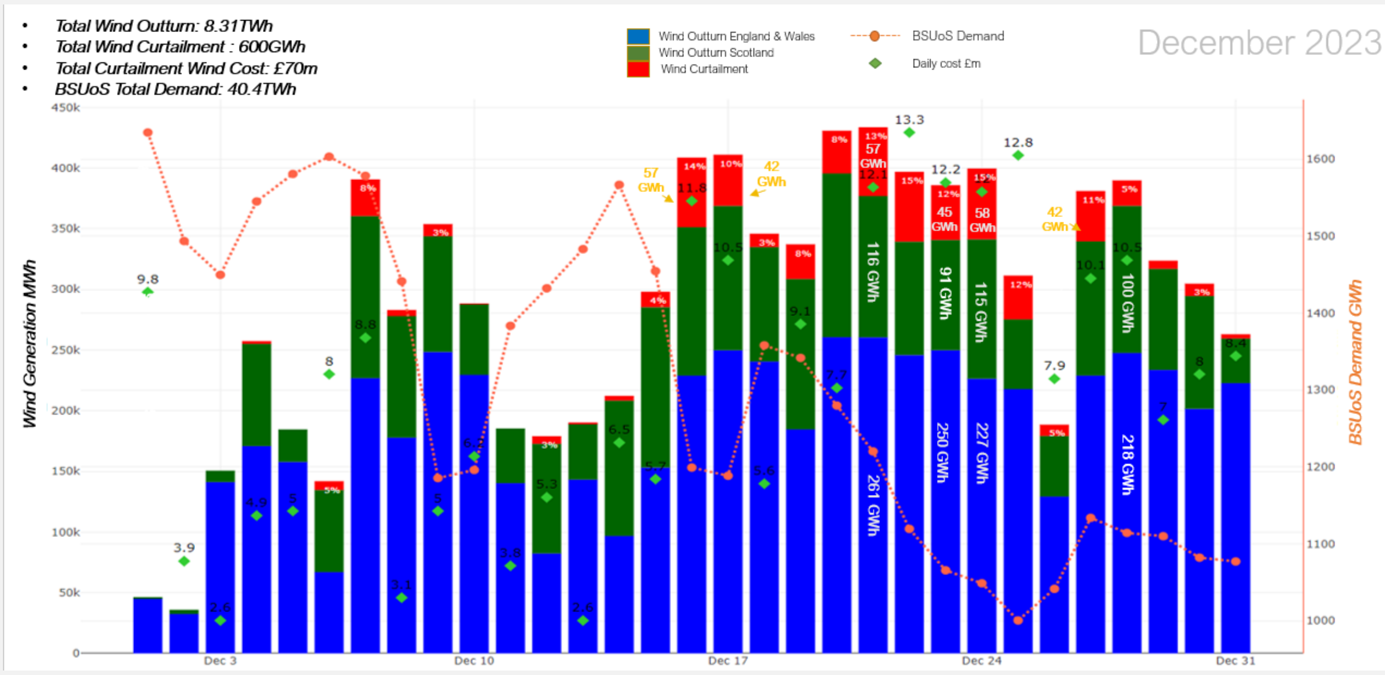
Cost breakdown for 22 December 2023

A minimum daily cost of £2.6m was observed on 3 December.

December Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

The chart below serves the purpose of supporting the transparency and the descriptions above. It is the daily "tour" of wind performance (wind generation: **blue** & **green** bars, and wind curtailment: **red** bars, demand resolved by the balancing mechanism and trades – **orange** dotted line and daily cost - **green** diamonds).

With this graph one can trace for example the relationship that may exist in how wind performance and low demand affect the cost of each day.



High-cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated ESO control room action.

Metric 1B Demand forecasting accuracy

This metric measures the average absolute MW error between day-ahead forecast demand (taken from Balancing Mechanism Report Service (BMRS[2]) as the National Demand Forecast published between 09:00 and 10:00) and outturn demand (taken from BMRS as the Initial National Demand Outturn) for each half hour period. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

A 5% improvement in historical 5-year average performance is required to exceed expectations, whilst coming within ±5% of that value is required to meet expectations.

In settlement periods where Optional Downward Flexibility Management (ODFM) and/or Demand Flexibility Service (DFS) are instructed by the ESO, this will be retrospectively accounted for in the data used to calculate performance. The ESO shall publish the volume of instructed ODFM to enable this to be done.

Performance will be assessed against the annual benchmark, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance through the year.

December 2023-24 performance

Indicative benchmark figures for 2023-24: Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure 2: 2023-24 Monthly absolute MW error vs Indicative Benchmark

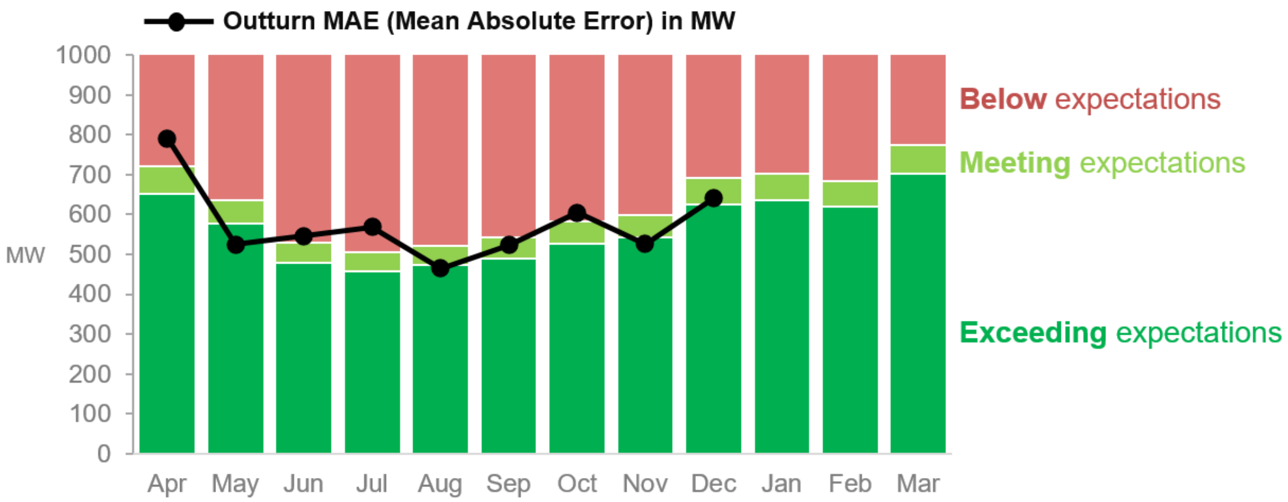


Table 4: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738
Absolute error (MW)	**791**	**523**	**546**	**569**	**465**	**523**	**604**	**526**	**640**			
Status	●	●	●	●	●	●	●	●	●			

[2] Demand | BMRS (bmreports.com)

Performance benchmarks:

- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

In December 2023, the mean absolute error (MAE) of our day ahead demand forecast was 640 MW which is meeting the benchmark.

Winter weather, human behaviour and holiday timings typically make December a difficult month for forecasting, but accuracy this month exceeded expectations on the majority of days.

A cold snap carried over from November to the first week of December, bringing hard frosts, some snow, and increased demands. This weather was swept away by storms Elin and Fergus, which brought wet, windy and disruptive weather. The weather then turned very mild for the remainder of December. These weather-related effects on demand (both directly and through embedded wind generation) were handled very well by our forecasters.

Christmas effects on demand can be difficult to forecast, with minimal reference data available. The highest errors in December were all around the seasonal holiday, which also overlapped with the very strong winds affecting embedded generation.

The distribution of settlement periods by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1488)
1000 MW	292	20%
1500 MW	112	8%
2000 MW	51	3%
2500 MW	12	1%

Missed / late publications

There were 0 occasions of missed or late publications in December.

Triads

Triads are the three half-hour settlement periods of highest demand on the GB electricity transmission system between November and February (inclusive) each year. They are separated by at least ten clear days to avoid all three triads potentially falling in consecutive hours on the same day, for example during a particularly cold spell of weather. We use the triads to determine TNUoS demand charges for customers with half-hourly meters. The triads are designed to encourage demand customers to avoid taking energy from the system during peak times if possible. This can lead to some uncertainty in forecasting peak demands over the winter months. See our website for more detail on triads.

Triad season introduces higher uncertainty over the demand during the Darkness Peak (DP) which is between settlement periods 34 and 39. At the time of the 1B forecast publication, i.e. by 09:15 on D-1, the forecast shows the national demand without any triad avoidance expectation. Each evening during the triad season we run an automatic assessment of triad activity, to establish if it occurred and how much avoidance there was over the settlement periods during the Darkness Peak. For the purpose of the 1B metric reporting, national demand outturn is adjusted by the estimated triad avoidance. All data is submitted as part of the reporting.

Triad charges have been reduced this year, and for this reason it is expected that triad avoidance behaviour will be lower than in previous years. However, there are likely other factors that may be contributing to reduced demand over the higher winter peaks (eg. increased energy costs) resulting in a similar ‘demand shaving’ over the peak demand times. This will likely make determining the amount of triad avoidance more difficult, as there is more overlap of these effects and less ‘unaffected’ days to use as a comparison.

In December we observed 3 days affected by triad avoidance behaviour – 1, 4 and 5 Dec, where there was an average of 522MW suppression over the darkness peak period.

Metric 1C Wind forecasting accuracy

This metric measures the average absolute percentage error (APE) between day-ahead forecast (between 09:00 and 10:00, as published on ESO Data Portal here) and outturn wind generation (settlement metering as calculated by Elexon) for each half hour period as a percentage of capacity for BM wind units only. The data will only be taken for sites that did not have a bid-offer acceptance (BOA) during the relevant settlement period.

We will publish this data on our Data Portal for transparency purposes. The benchmarks are drawn from analysis of historical errors of the five years preceding the performance year. 5% improvement in performance expected on the 5-year historical average, with range of ±5% used to set benchmark for meeting expectations.

December 2023-24 performance

Indicative benchmark figures for 2023-24:	Please note that the benchmark figures used below are indicative only. We have calculated these in line with the method specified by Ofgem, but we have not yet received the confirmed figures from Ofgem. We will update previous performance figures in subsequent reports once the benchmarks have been finalised.

Figure 3: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmark

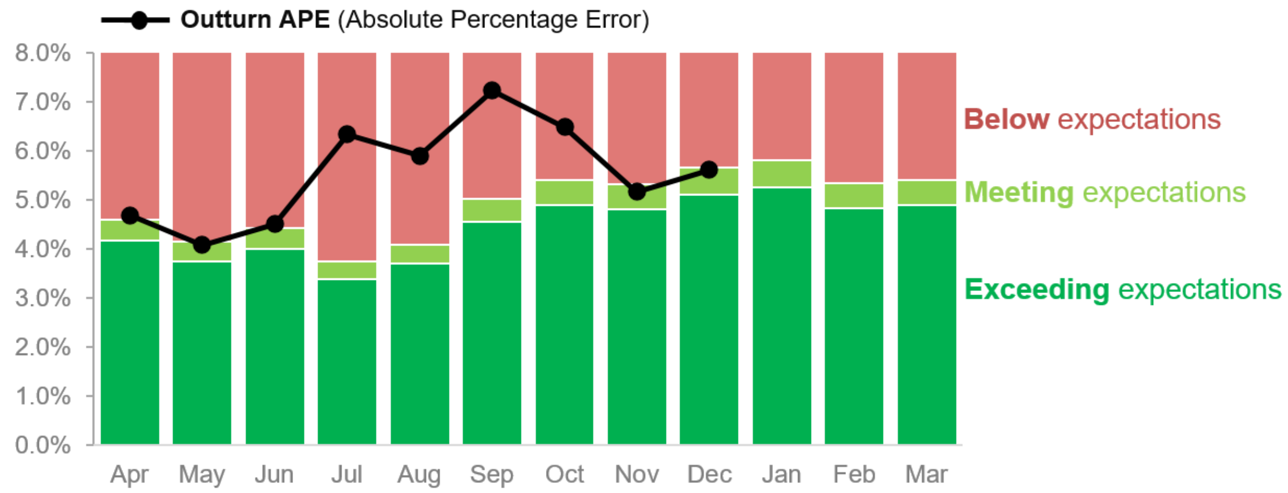


Table 5: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.38	3.95	4.21	3.57	3.89	4.79	5.15	5.06	5.38	5.53	5.08	5.14
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**	**6.48**	**5.16**	**5.61**			
Status	●	●	●	●	●	●	●	●	●			

Performance benchmarks:

- **Exceeding expectations:** < 5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** > 5% higher than 95% of average value for previous 5 years.

Supporting information

In December 2023, the mean absolute error (MAE) of our day ahead Wind forecast was 5.61% compared to the indicative ‘meeting expectations’ benchmark of 5.38%, and thereby meeting expectations for the second consecutive month.

December was largely a very windy month, with lengthy periods of sustained high winds. Forecasts were regularly above 18GW, with the GB record (to date) outturn of 17.4GW experienced on 20th December.

Wind forecast inaccuracy was largely attributed to only three very poor performing days. One attributed to external weather data error (8th) and two being down to significant CfD market activity on 24th and 29th.

In general, forecasting inaccuracies on any given day, are usually now down to a small number of windfarms.

Where available, we are now using selective windfarm outage data, focusing on those units which have the greatest variance and error contribution.

Wind forecasting remains challenging, with our current legacy systems and data. Almost all model updates and outage profiles have to be updated manually, until such time that PEF (R5) Wind system is Production-ready – currently estimated to be Q2 FY25.

Withdrawal of wind units

No units withdrew availability between time of forecast and time of metering.

Missed / late publications

In December there were no occasions of late or missing publications of the forecast.

Metric 1D Short Notice Changes to Planned Outages

This metric measures the number of short notice outages delayed by > 1 hour or cancelled, per 1000 outages, due to ESO process failure.

December 2023-24 performance

Figure 4: 2023/24 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

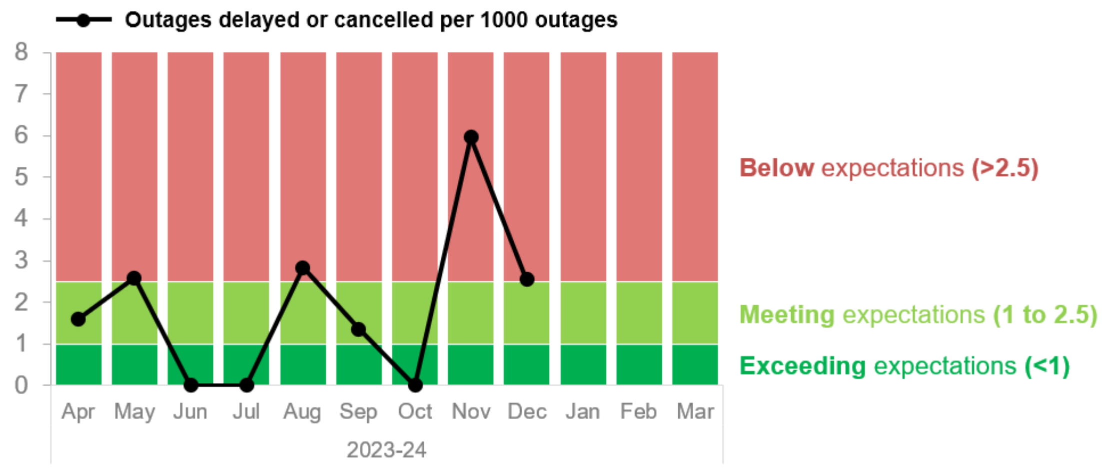


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734	704	671	393				5,860
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1	0	4	1				11
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4	0	6	2.5				1.88
Status	●	●	●	●	●	●	●	●	●				●

Performance benchmarks:

- **Exceeding expectations:** Fewer than 1 outage delayed or cancelled per 1000 outages
- **Meeting expectations:** 1-2.5 outages delayed or cancelled per 1000 outages
- **Below expectations:** More than 2.5 outages delayed or cancelled per 1000 outages

Supporting information

In December we successfully released 393 outages. There was one delay or cancellation due to an ESO process failure. The number of stoppages or delays per 1000 outages for December was 2.54, which is outside the 'Meets Expectations' target of less than 2.5 and therefore 'below expectations'.

The cumulative number of stoppages or delays per 1000 outages for 2023/24 is 1.88 which is within the 'meeting expectations' target.

The single event in December is summarised below:

- There was a delay on an outage due to a communication error between the ESO and a Distribution Network Operator (DNO) on the ‘demand at risk’ process. The outage impacted two DNOs and therefore required coordination between all three parties to complete the ‘demand at risk’ process. The post-fault demand recovery strategy was discussed with all three parties. However, the ESO planner had assumed the strategy was acceptable as there was no response from one of the DNO’s. As one of the DNO’s hadn’t confirmed the outage, this DNO control room was not aware of the outage and it was delayed. An Operational Learning Note (OLN) has been written and shared internally about the coordination of agreements for sites which affect multiple DNO parties. Additionally, it has been captured to escalate cases on non-responses to seek feedback rather than making assumptions.

RRE 1E Transparency of operational decision making

This Regularly Reported Evidence (RRE) shows the percentage of balancing actions taken outside of the merit order in the Balancing Mechanism each month.

We publish the Dispatch Transparency dataset on our Data Portal every week on a Wednesday. This dataset details all the actions taken in the Balancing Mechanism (BM) for the previous week (Monday to Sunday). Categories and reason groups are allocated to each action to provide additional insight into why actions have been taken and ultimately derive the percentage of balancing actions taken outside of merit order in the BM.

Categories are applied to all actions where these are taken in merit order (Merit) or an electrical parameter drives that requirement. Reason groups are identified for any remaining actions where applicable. Additional information on these categories and reason groups can be found on our Data Portal in the Dispatch Transparency Methodology.

Categories include: System, Geometry, Loss Risk, Unit Commitment, Response, Merit

Reason groups include: Frequency, Flexibility, Incomplete, Zonal Management

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions being taken out of pure economic order allows us to focus our development and improvement work to ensure we are always making the best decisions and communicating this effectively to our customers and stakeholders.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

- actions we are taking to increase understanding of the ESO's operational decision making
- insight into the reasons why actions are taken outside of merit order in the Balancing Mechanism
- activity planned and taken by the ESO to address and reduce the need for actions to be taken out of merit order.

December 2023-24 performance

Figure 5: 2023-24 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

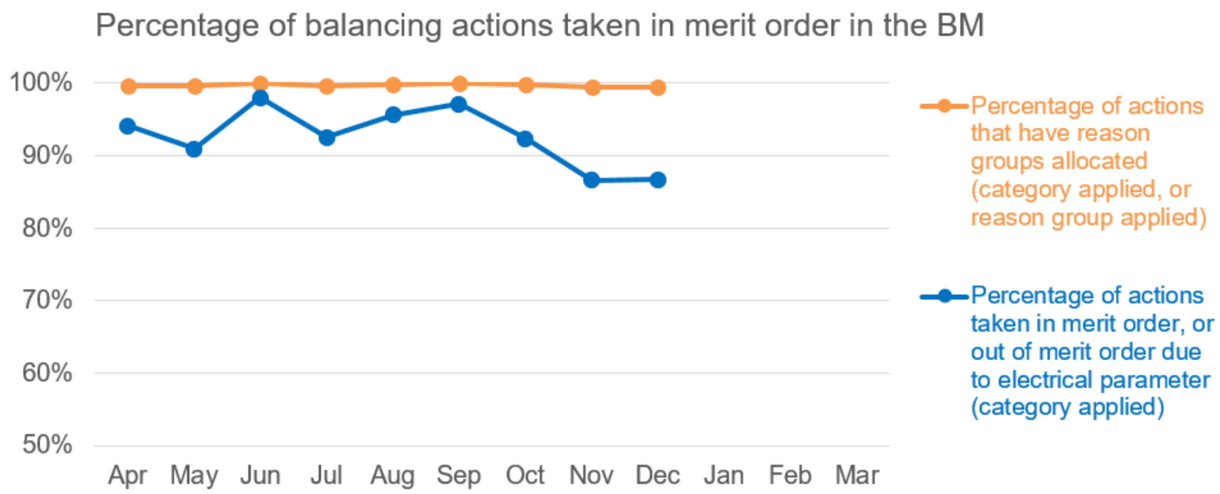


Table 7: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	94.1%	90.9%	98.0%	92.5%	95.6%	97.1%	92.3%	86.6%	86.7%			
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%	99.9%	99.8%	99.5%	99.5%			
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%	0.3%	0.2%	0.1%	0.2%	0.5%	0.5%			

Supporting information

December performance

This month 86.7% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 12.8% of actions were allocated to reason groups for the purposes of our analysis, and the percentage of actions with no category applied or reason group identified remained in line with previous months. During November 2023, there were 65745 BOAs (Bid Offer Acceptances) and of these, only 340 remain with no category or reason group identified, which is 0.5% of the total.

Other activities

In late December LCP completed the first phase of their independent analysis of the dispatch transparency dataset. Following a joint review of these results we have worked closely with LCP to define the additional work required in a second phase to provide greater insight into how the data can be used to identify and explain the reasons for “skips”.

We published the updated ESO Transparency Roadmap on 21 December including our high-level roadmap for improvements for Dispatch Transparency data. More information on this improvement timeline plus how we intend to engage with wider industry going forward and on an enduring basis will be provided at the follow-up storage webinar following LCP completion of the second phase work.

We have identified the missing data periods from the published dataset for the current financial year (from 1 April 2023) and continue work to develop a reliable method to retrieve or reconstruct these sections in order to provide a comprehensive dataset. We are progressing with the code review of the automated process and checks on reference data sources within the other ESO systems to identify and resolve additional root causes. We are committed to maintaining and improving the current Dispatch Transparency tool while we work with industry to build on LCP’s recommendation and co-create a new Dispatch Transparency dataset. We will be sharing more details about the work on the existing and replacement datasets at the event in January.

RRE 1F Zero Carbon Operability Indicator

This Regularly Reported Evidence (RRE) provides transparency on progress against our zero-carbon operability ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate.

For this RRE, each generation type is defined as whether it is zero carbon or not. Zero carbon generation includes hydropower, nuclear, solar, wind, battery and pumped storage technologies. As this RRE relates to the ESO's ambition to be able to operate a zero carbon transmission system by 2025, only transmission connected generation is included and interconnectors are excluded (as EU generation is out of scope of our zero carbon operability ambition). Note that the generation mix measured by RRE 1F and RRE 1G differs.

The Zero Carbon Operability (ZCO) indicator is defined as:

$$ZCO(\%) = \frac{(Zero\ carbon\ transmission\ connected\ generation)}{(Total\ transmission\ connected\ generation)} \times 100$$

Part 1 – Defining the maximum ZCO limit for BP2

Below we define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP2, explaining which deliverables are critical to increasing the limit.

Table 8: Forecast maximum ZCO% after our operational actions

BP2 2023-25	Maximum ZCO limit	Calculation and rationale
Start of BP2 (Q1 2023-24)	**90% - 95%**	The maximum ZCO% achieved to date is 90%, set in January 2023. New frequency products and voltage and stability pathfinders are the main projects delivering increased ZCO% during the early part of BP2. The methodology for calculating ZCO% is consistent with BP1 and our continued delivery of projects and programmes increases the opportunity to operate the system at higher ZCO%. In Q3 2023-24 we have achieved a new record of 91.3% on 28 December. We also operated 34 settlement periods with a ZCO% of 90% or more. All these settlement periods fell between 23 and 30 December.
End of BP2 (Q4 2024-25)	**95% - 100%**	We expect that our remaining projects, products and programmes will enable us to operate at 100% ZCO in 2025. Our operational strategy is set to deliver some key projects which will increase the maximum ZCO% over the BP2 period. These key deliverables are the deployment of our full suite of response and reserve products, voltage and stability pathfinders, further reduction of minimum inertia requirement via the Frequency Risk and Control methodology (FRCR) and improved tools for monitoring system inertia. These deliverables are either enabling zero carbon providers of ancillary services or increasing the window in which we can operate the system securely.

Part 2 – Regular reporting on actual ZCO

Every quarter we report the ZCO provided by the market versus the ZCO following ESO actions. This is presented at a monthly granularity.

The table below is calculated according to the formula for ZCO for each settlement period for every day over the reporting period. ZCO is a percentage of the zero-carbon transmission generation (hydropower, nuclear, solar, wind, battery and pumped storage technologies) divided by the total transmission generation. Two figures are calculated: one represents the system conditions before ESO interventions are enacted, the other is after. This indicator measures progress against our zero-carbon operability ambition by showing the proportion of zero carbon transmission generation that the system can accommodate.

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in Q2 was 98% on 28 September, settlement period 8. However, for that period the final ZCO dropped to 80% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table 9: six-month maximum zero carbon generation percentage by month (2023-24)

Month	Highest ZCO% in the month (after ESO operational actions)	ZCO% provided by the market (during the same day and settlement period)	Date / Settlement Period
April	83.6%	90.7%	10 Apr / 36
May	79.6%	88.0%	4 May / 24
June	79.9%	92.3%	10 Jun / 33
July	83.9%	90.9%	3 Jul / 22
August	82.9%	96.0%	19 Aug / 29
September	89.1%	97.1%	24 Sep / 31
October	86.8%	92.0%	3 Oct / 30
November	84.0%	90.2%	2 Nov / 46
December	91.3%	97.5%	28 Dec / 30

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

Figure 6: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

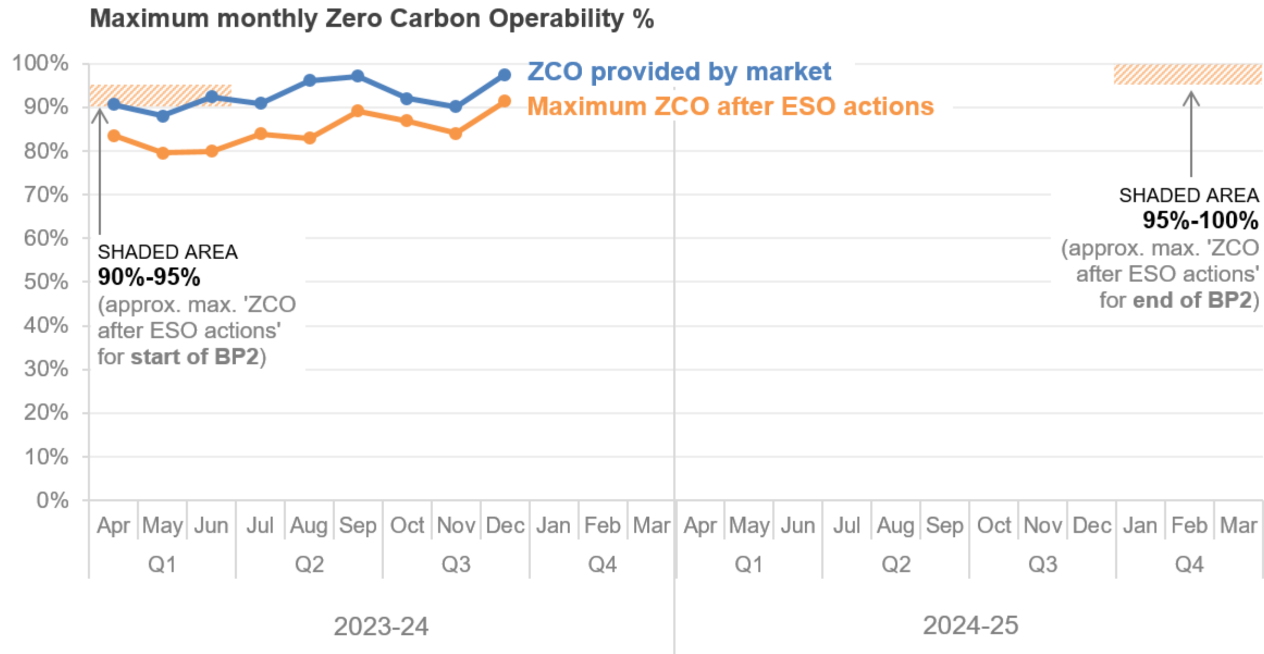
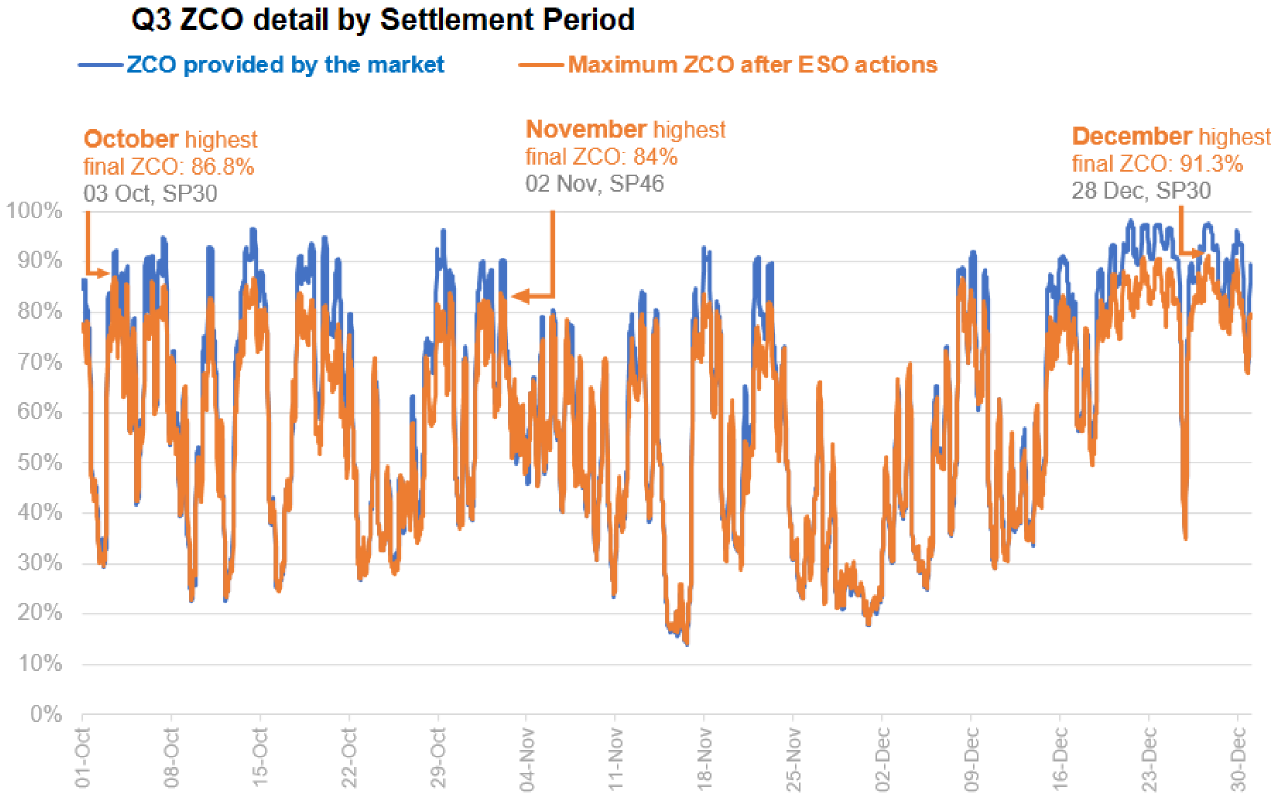


Figure 7: Q3 2023-24 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

A new ZCO% record of 90.7% was achieved on 23 Dec 2023. This was then broken on 28 Dec 2023 at 91.3%. The previous record was 90.3% on 7 Jan 2023.

Every month in Q3 saw an increase compared to 2022 (see table below); evidence that our innovative approach to system operation and new ancillary service products continue to enable the transition to net zero.

On October's highest ZCO day, the need for additional inertia was the main driver for keeping synchronous generation on the system. However, wind bids were required for constraints and downward margin.

Storm Ciaran was over the UK for the November highest ZCO day. Greater volumes of constraint bids were taken to leave additional margins on key constraint boundaries. Additional generation was run for voltage and inertia to provide adequate geographical spread and reduce risks associated with Storm Ciaran.

On December's highest ZCO day, some additional generation was required for voltage, but far more generation was required for energy reasons, despite high wind generation output.

New reactive power assets, inertia from Stability services and our plans to reduce the minimum inertia requirement by 2025 will negate the need for these actions in future.

The lowest ZCO% this month was across 16 and 17 November. Very low wind output of <1,000MW was the main driver for this.

Highest final ZCO by month vs previous year

Quarter	Month	2022	2023	Difference
Q1	April	83.7%	83.6%	-0.2%
	May	78.5%	79.6%	1.1%

	June	76.7%	79.9%	3.2%
Q2	July	73.9%	83.9%	10.0%
	August	67.3%	82.9%	15.6%
	September	73.5%	89.1%	15.6%
Q3	October	77.6%	86.8%	9.2%
	November	74.3%	84.0%	9.7%
	December	84.8%	91.3%	6.5%

RRE 1G Carbon intensity of ESO actions

This Regularly Reported Evidence (RRE) measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

It is often the case that balancing actions taken by the ESO for operability reasons increase the carbon intensity of the generation mix. More information about the ESO's operability challenges is provided in the Operability Strategy Report.

December 2023-24 performance

Figure 8: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

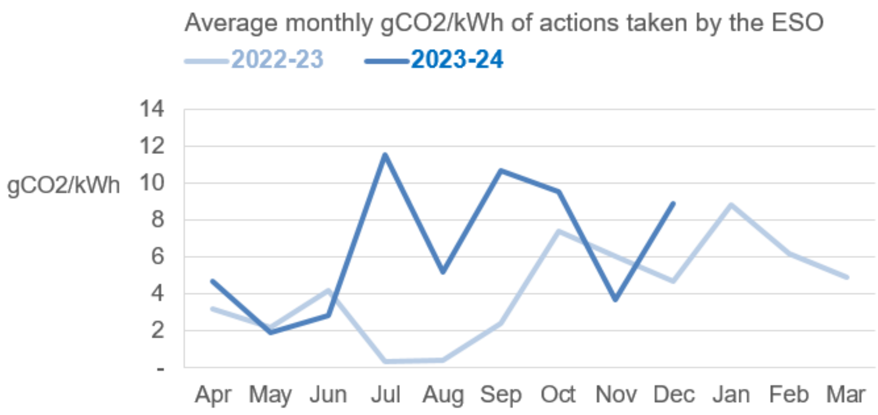


Table 10: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	4.7	1.9	2.8	11.6	5.2*	10.7*	9.5*	3.7	8.9			

Supporting information

***Data issue (Aug-Sep):** As reported previously there are eight days' incorrect data in August, one day's data missing in September and four in October. We have a temporary fix in place which means that data has been complete from November onwards. We're working to correct the August to October data and working on a permanent fix.

In December 2023, the average carbon intensity of balancing actions was 8.9gCO2/kWh. This is 4.2g higher than Dec 2022 (which was 4.7gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 18% of settlement periods.

December 2023 was a tale of two halves. From 1 to 15 Dec, average carbon intensity was 227gCO2/kWh with wind making up 30% of the generation mix on average. ESO actions therefore had little impact on carbon intensity (1.1gCO2/kWh). From 16 to 31 Dec wind generation increased significantly to 53% on average with 10 days experiencing wind in excess of 20GW, reducing the carbon intensity to 82gCO2/kWh. ESO actions had a greater impact during this period as we required additional inertia almost every day during the period. The reduction in minimum inertia policy through FRCR will remove the need for many of these units in future.

The greatest impact of ESO actions on carbon intensity was seen over the weekend of 16-17 December, raising the carbon intensity by 26g on average across the weekend. Constraints in Scotland and Northern England required 4.6GW of wind bids to solve. Some Hydro and Pump Storage assets could not reduce generation or pump due to full lakes. Instructions for these were optimised to ensure availability during evening peak and morning demand ramp up. Multiple generators were required for voltage and inertia needs.

The lowest carbon intensity which could have been provided by the market was on the 24 December 18:30-19:00 (~20gCO_2/kWh) with high wind (~21.5GW) and other zero carbon sources providing around 79% of the generation mix (after ESO actions). Additional synchronous units were required to maintain inertia after the demand peak and in readiness for overnight voltage control, which raised the carbon intensity to ~35gCO_2/kWh.

RRE 1H Constraints Cost Savings from Collaboration with TOs

The Transmission Operators (TOs) need access to their assets to upgrade, fix and maintain the equipment. TOs request this access from the ESO, and we then plan and coordinate this access. We look for ways to minimise the impact of outages on energy flow and reduce the length of time generation is unable to export power onto the network.

This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

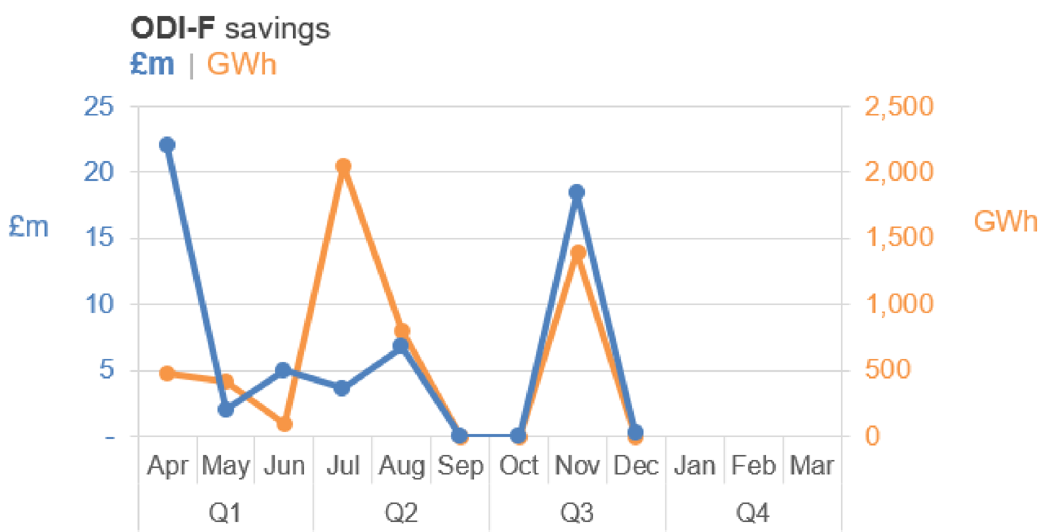
There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

1. ODI-F savings: Actions taken through the System Operator: Transmission Owner (SO:TO) Optimisation ODI-F
    - Output Delivery Incentives (ODIs) are incentives that form part of the TOs' RIIO-2 framework. They are designed to encourage licensees to deliver outputs and service quality that consumers and wider stakeholders want to see. These ODIs may be financial (ODI-F) or reputational (ODI-R).
    - One of these ODIs, the SO:TO Optimisation ODI-F, is a new two-year trial incentive to encourage the Electricity Transmission Owners (TOs) to provide solutions to the ESO to help reduce constraint costs according to the STCP 11-4[3] procedures. The ESO must assess the eligibility of the solutions that the TOs put forward in line with STCP 11-4, and must deliver the solutions in order for them to be included as part of the SO:TO Optimisation ODI-F and this RRE 1H.
    - For RRE 1H, where constraint savings are delivered through the SO:TO Optimisation ODI-F, the savings are calculated in line with the methodology for that incentive.
2. Other savings: Actions taken separate from the SO-TO Optimisation ODI-F

The ESO also carries out other activities to optimise outages. In these cases, the assumptions used for estimating savings will be stated in the supporting information.

Figure 9: Estimated £m savings in avoided constraints costs (ODI-F) – 2023-24

(Estimated savings in GWh are also shown for context)



[3] The STCP 11-4 'Enhanced Service Provision' procedure describes the processes associated with the ESO buying a service from a TO where this service will have been identified as having a positive impact in assisting the ESO in minimising costs on the GB Transmission network.

Figure 10: Estimated £m savings in avoided constraints costs (Other) – two-year view

(Estimated savings in GWh are also shown for context)

*Note **vertical axes scales** differ from the ODI-F graph above.*

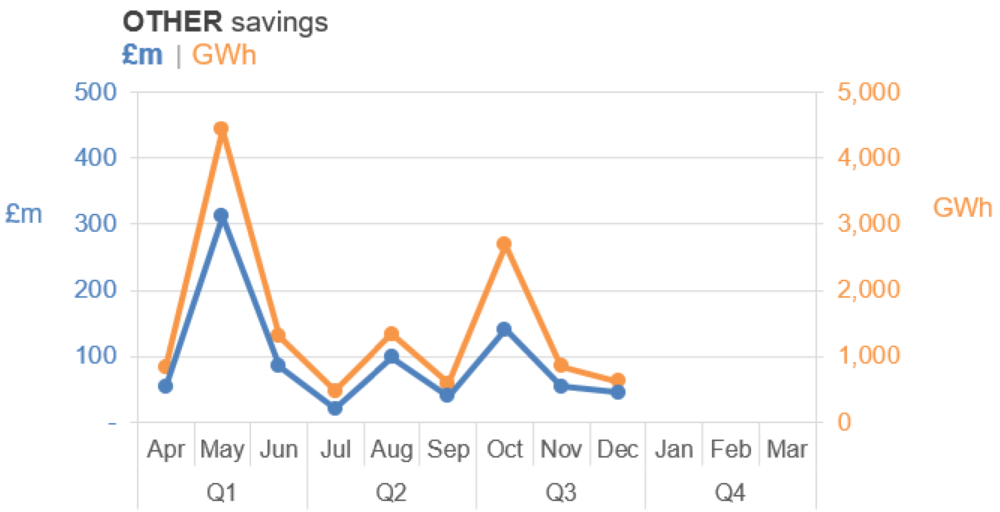


Table 11: Monthly estimated £m savings in avoided constraints costs (2023-24)

	ODI-F savings	Other savings	ODI-F savings	Other savings
	£m	£m	GWh	GWh
Apr	22.0	53.4	474	827.6
May	2.0	311.4	416	4425.4
Jun	5.0	84.9	87	1309.9
Jul	3.6	21.5	2052	486.3
Aug	6.8	99.1	793	1345.3
Sep	-	40.5	-	593.1
Oct	-	140.6	-	2688.0
Nov	18.4	55.2	1394	857.1
Dec	0.2	45.5	-	628.8
Jan				
Feb				
Mar				
YTD	**58.0**	**852.1**	**5216**	**13161.5**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out.

Prices of £36 per MWh are used for conventional generation and £75 per MWh for renewable generation.

Supporting information

Data issue: For the ODI-F/11-4 section, the data has been updated to track more accurate real value provided to the end consumer. This has been done by calculating the outturn costs of each 11-4 opportunity. Unfortunately, the GWh savings for outturn have not been logged currently. This will be updated for future reports. For this report, the outturn GWh is estimated from the forecast figures.

ODI-F (STCP 11-4) Constraint Cost Savings

The Network Access Planning (NAP) team has progressed and approved 2 enhanced service provisions from TO's through STCP 11.4 that have provided constraint cost savings this quarter. These include:

- A thermal limit circuit enhancement was agreed with the TO, in the Northwest of England. This enhancement provided 20.5 GWh of energy saving and has a calculated outturn saving of £1.7 million to the end consumer.
- A thermal enhancement was agreed for a circuit in north Wales. This enhancement provided a saving of 0.1 GWh and a financial benefit of £2790 to the end consumer.

In this quarter, NAP has realised around **£1.7 million of constraint cost savings** through STCP 11.4. This includes only works with outturn costs available and calculated and is therefore a lower bound on constraint cost savings.

Financial savings have been accurately calculated across the year for the outturn costs. No forecast savings are included in the data for this section. GWh savings are proportionally estimated from forecasts and therefore subject to change.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded **59 instances this quarter** where the ESO's actions directly resulted in adding value to the end consumers and its innovative ways of working facilitated increased generation capacity to the connected customers.

Such actions include moving outage dates, splitting/separating outages, reducing return to service times, obtaining enhanced ratings from TOs, re-evaluating system capacity, identifying and facilitating opportunity outages, aligning outages with customer maintenance and generator shutdowns, proposing, and facilitating alternative solutions for long outages that impact customer, and many more.

Some examples of these instances, for quarter 3, include:

- In October, voltage optimisation benefit has been summated and added to the customer value opportunities. This covers the period since the start of the financial year up to engineering week 35. This includes NAP voltage engineers optimising the existing plan against changes in short term timescales and reducing overnight voltage plant requirements hence saving money for the end consumer. A total of 879.1 GWh of initially requested voltage support was saved via these continuous actions equating to £31.6 million saved for the end consumer which would be unnecessarily planned without the short-term voltage engineers.
- In November, NAP working closely with SSEN-T arranged for optimisations of outage placement for key reconductoring works on the East Coast in the North of Scotland. A double circuit request was made at short notice within year by the TO due to newly identified requirements in the scheme works. The ESO rejected this initial request that would heavily restrict the B2 boundary over the winter period and is working with the TO to arrange placement for this outage at a less onerous time of year. This removed a 1GW drop for 9 days on the B2 boundary. This saved 224 GWh on constraint costs. Increased flow on the B2 boundary in this period allowed for higher flow across the B4 boundary. This saving is equivalent to £16.8m to the end consumer, or the energy required to meet the electricity requirement for 83,000 uk homes for a year.
- At the start of December, national and regional teams at the ESO, working together with the current year planners at NGET, spotted an opportunity to align works in the East of England. Conditions allowed for two outages which are both individually cause constraints in the region to

be nested together to reduce the duration of constraints in the area. This combination removed an 800 MW thermal constraint on a variation of the EC5 boundary in the East of England for 17 days. By nesting these outages in the same window, the ESO was able to provide 326.4 GWh of conventional generation saving that did not need to be constrained at cost and then bought back on elsewhere in the country at further cost to the end consumer. This equates to around £24.5 million saved, equivalent to the electrical power consumed by 120,800 uk homes in a year.

These and many more represent a total of **13.2 TWh (approximately £872M)** of extra generation capacity, which would have otherwise been constrained at a cost to the consumer. This is the same power required for 942,800 UK homes for a year assuming all power requirements of a household are met by electricity, or 4.9 million UK homes for a year where power requirements are met by both electricity and gas.

A note on updated costings, the conversion from MWh saving to £ saved is now done assuming 30% effectiveness of all optimisations and using bid off costs plus replacement energy costs on the current system as £120/ MWh for conventional generation and £250/ MWh for renewable generation.

Therefore, wind-based constraint enhancements are converted at £75/ MWh, gas-based constraint enhancements are converted at £36/ MWh, and demand improvements are converted at £50/ MWh.

Average energy usage for a UK home is using information from Ofgem’s website under information for customers - energy advice for households - average gas and electricity usage.

RRE 1I Security of Supply

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where 'f' represents frequency:

Deviation (Hz)	**Duration**	**Likelihood**
$f > 50.5$	Any	1-in-1100 years
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

December 2023-24 performance

Table 12: Frequency and voltage excursions (2023-24)

	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0			
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	0	0	1			
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0	0	0	0			

Supporting information

December performance

There have been no reportable voltage and one frequency excursion for December 2023. On 22 December 2023 at 13:10, IFA1 bipole 1 tripped while importing 1000MW from France. A subsequent trip happened on CDCL-1 exporting ~440MW at the same time. The frequency reached a maximum deviation of 49.266Hz returning to steady state limit (49.5Hz) within 60 seconds.

[4] https://www.nationalgrideso.com/research-publications/transmission-performance-reports

RRE 1J CNI Outages

This Regularly Reported Evidence (RRE) shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

December 2023-24 performance

Table 13: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

	2023-24											
Unplanned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0	0	0			
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0			

Table 14: 2023-24 Planned CNI System Outages (Number and length of each outage)

	2023-24											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	1 outage (185 mins)	0	0	1 outage (265 mins)	1 outage (145 mins)	1 outage (170 mins)	0			
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0			

Supporting information

December performance

There were no outages, either planned or unplanned, encountered during December 2023.

Notable events during December 2023

Release 1 of the Open Balancing Platform went live on 12 December

The aim of the Balancing Programme is to maintain and bring change into our current balancing capabilities to support Control Room operations, whilst we transform to new balancing capabilities that we need to deliver reliable and secure system operation, facilitate competition for the benefit of consumers, and meet our ambition for net-zero carbon operability.

On 12 December the Balancing Programme went live with Release 1 of the Open Balancing Platform (OBP). OBP, which is being delivered using agile methodology, is set to replace our current balancing systems over the coming years. This first release of OBP provides bulk dispatch capability within the control room for two zones - Batteries and Small Balancing Mechanism Units (BMUs) - and is the foundation for all future system developments. Bulk Dispatch is a new tool that enables our control room engineers to send bulk instructions to smaller BMUs and to battery storage sites, allowing them to play a more active role in balancing the network. Improving this capability is a big step forwards on our journey to enabling a zero-carbon system.
Based on stakeholder feedback we received earlier this year, we expanded our scope for Release 1 of OBP to include an additional zone (Battery) for launch alongside the Small-BMU which was originally scheduled.
We anticipate the following benefits associated with Release 1 of OBP:

- Improved situational awareness enabling a reduction in skip rates and increased use of flexible assets
- Instructions will increase from 2-3 per minute to circa 50 instructions multiple times per hour
- Reduced CO_2
- £15million consumer benefit per annum

Further releases will happen throughout 2024 and we will continue to engage with industry on future developments and our delivery roadmap. You can view all our latest information here and sign up to receive future updates here.

Megawatt Dispatch breaks new ground with first live Distributed Energy Resources curtailment

In November, we carried out our first ever live dispatch of power that is being generated by a Distributed Energy Resource (DER) connected to the Distribution network and providing power into the main electricity transmission system. By dispatch we mean asking the provider to reduce their power generation output in order to help us manage the capacity on the transmission system, and in particular manage capacity transfer constraints in a particular geographical area.

What are the benefits of this? In certain circumstances and in certain areas there is sometimes more power being generated and trying to flow from one part of the network to another than it can safely handle, so from time to time we need to reduce this generation. We have implemented a service called MW Dispatch which allows us to do this in conjunction with the local Distribution Network Operator and the end power generators. This means that our Control Engineers who have clear view of power flow across these constrained areas can issue an instruction to reduce the DER generation, thus managing the flow constraint. The positive for the generators is that they can get paid for making this reduction to help us manage the network. It also allows us to connect more power generation assets in the Distribution network than we would normally be able to ahead of expensive and time consuming network reinforcement works – so speeding up and increasing the volume of Connections.

New Oscillation situational awareness tool Proof of Concept rolled out

Following the frequency oscillations experienced over the summer the Network Control Programme have been working with one of our suppliers to get a new, real-time oscillation monitoring tool available to our Control Engineers.

Using their existing frequency monitoring devices, which support one of our existing Inertia Monitoring systems, Reactive Technologies have developed a proof of concept monitoring two locations within

Scotland to provide awareness of the occurrence of oscillations. Following some initial offline analysis of the events, Reactive Technologies were able to develop and test and deliver an initial solution within their existing platform in 4 months.

The solution is now available to Control Engineers and is being assessed to understand the accuracy and usability with regular feedback to Reactive Technologies to improve the presentation of data to end users.

Role 2 (Market developments and transactions)

ESO

Metric 2Ai Phase-out of non-competitive balancing services

This metric measures the percentage of services procured by the ESO that are procured on a non-competitive basis. For the purpose of this metric, we consider a 'non-competitive' service to be either a bilateral contract or a service with significant barriers to entry. It excludes SO-SO trades, which are trades made between system operators of connected countries. These are used to determine the direction of electricity flow over interconnectors. The volumes reported in this metric are those delivered within the time period.

There are benchmarks for the following categories: Frequency Response (FR) and Reserve, Reactive Power, and Constraints.

Benchmarks are set based on the ESO's current and projected procurement for each of these services:

Category	Benchmark	Assumptions applied in BP2 benchmark
FR and Reserve	Year 1: 25% Year 2: 20%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • Reserve will continue to be procured competitively until the implementation of new reserve services
Reactive power	Year 1: 90% Year 2: 90%	• Historical data was analysed from the previous reporting period (BP1) and no uplift applied for the benchmark • Competitive procurement of Reactive Power through Market mechanisms will be understood later in 2023/4 – through the Reactive Power Market Reform. • There will continue to be specific regional requirements, and these will be procured through market mechanisms where feasible.
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • B6 Commercial Intertrip service was the first Constraint service to be delivered competitively. More will be delivered through market mechanisms in BP2, such as Constrain Management Intertrip Service (EC5 CMIS) and Local Constraint Market (LCM)

The non-competitive percentage is calculated on a volume basis, which is measured in MWs, with the exception of Reactive Power which is measured in MVAr.

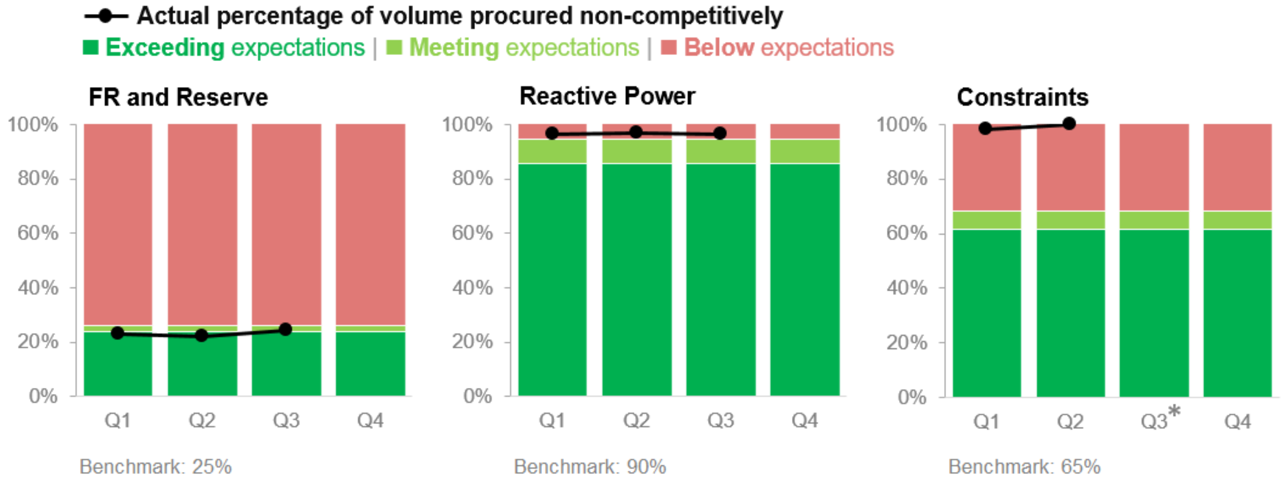
These expectations are set for the current suite of products and may be revised if new products are introduced.

Category	Services procured **competitively**	Services procured **non-competitively**
Frequency Response	• FFR (Firm Frequency Response) Secondary, High and Static • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Fast Start
Reserve	• Day Ahead STOR (Short Term Operating Reserve)	• Long Term STOR • Optional Fast Reserve • Super SEL (Stable Export Limit) (Footroom)
Reactive Power	• Mersey Reactive Power Pathfinder • Pennines Pathfinder	• Reactive • Mandatory Reactive Lead & Lag • Stability Reactive Lead & Lag • Reactive Sync Comp, Comp Lead and Comp Lag • Inertia (Stability)
Constraints	• B6 Intertrip	• Strike Price

Overall performance – All services

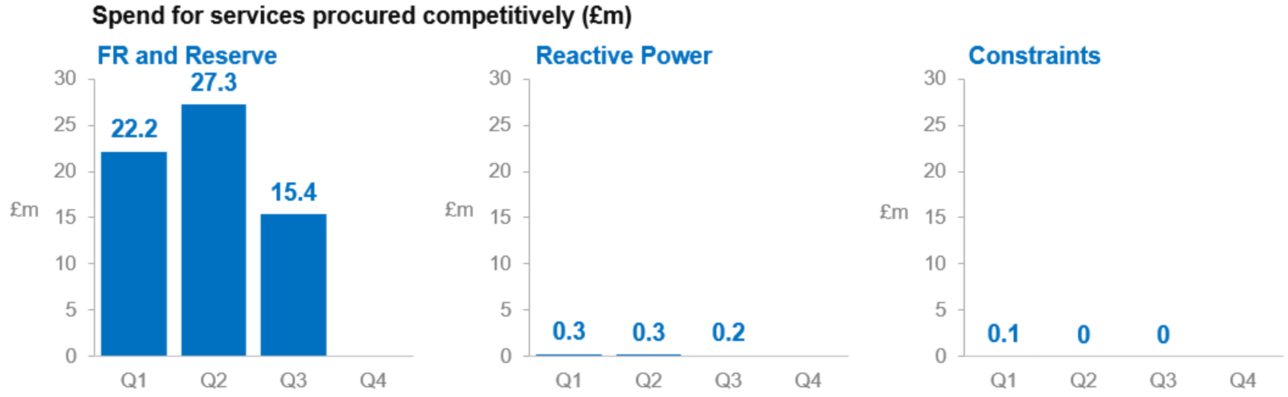
Q3 2023-24 performance

Figure 11: Percentage of volume procured non-competitively vs benchmark



Constraints Q3* - as no volume was procured in Q3, there is no figure for percentage of volume procured non-competitively, and no point on the graph.

Figure 12: Quarterly competitive spend by service



SO-SO trades made during Q3

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO. EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CBB.

Trades for Q1 totalled £0.06m consisting of 2 trades on Moyle interconnector.

Trades for Q2 totalled £0.2m consisting of 3 trades, 2 on the Moyle Interconnector and one on the IFA-1 Interconnector.

Trades for Q3 totalled £0m consisting of 0 trades on 0 interconnector/s.

	Data content Information:	Data consists of final settlement data for the first two months of the most recent quarter with the third month to be provided within the next submission of the report.

1. Frequency Response and Reserve

Q3 2023-24 performance

Table 13: Frequency Response and Reserve percentage of services procured on a non-competitive basis, and spend.

Frequency Response & Reserve		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWh	13,742	15,638	10,058	
	Volume procured non-competitively	GWh	3,154	3,476	2,469	
	Percentage of volume procured non-competitively	%	**23%**	**22%**	**25%**	
	Year 1 benchmark	%	25%	25%	25%	25%
	Status	n/a	●	●	●	
Spend	Total spend	£m	46.7	52.1	29.5	
	Spend for volume procured competitively	£m	22.2	27.3	15.4	
	Spend for volume procured non-competitively	£m	24.5	24.8	14.1	

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 is 20%

Supporting information

In Q3, 25% of Frequency Response and Reserve volume was procured non-competitively compared to the benchmark of 25%, and therefore meeting expectations.

With the growth in response and reserve competitive markets we are able to procure more of our requirements at the day ahead so have less reliance on non-competitive procured services. As more reserve services are introduced to day-ahead procurement we expect to see further reductions in the Frequency Response and Reserve volumes that are procured non-competitively. For Long Term STOR, we remain committed to the legacy ~ 400MW volume of contracts which expire in April 2025. This volume will then be replaced by volumes procured at day ahead through the new reserve products.

2. Reactive Power

Q3 2023-24 performance

Table 14: Reactive Power percentage of services procured on a non-competitive basis, and spend.

Reactive Power		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GVARh	15,650	16018	10,356	
	Volume procured non-competitively	GVARh	15,126	15,488	10,004	
	Percentage of volume procured non-competitively	%	**97%**	**97%**	**97%**	
	Year 1 benchmark	%	90%	90%	90%	90%
	Status	n/a	●	●	●	
Spend*	Total spend	£m	76.6	68.2	46.0	
	Spend for volume procured competitively	£m	0.3	0.3	0.2	
	Spend for volume procured non-competitively	£m	76.3	67.9	45.8	

*Rounding: Spend figures in £m are rounded to the nearest 1 decimal place, therefore Total spend may differ slightly from the sum of competitive and non-competitive spend.

Performance benchmarks:
- ● **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- ● **Meeting expectations:** within ±5% of the annual procurement benchmark
- ● **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 remains at 90%

Supporting information

In Q3 97% of Reactive Power volume was procured non-competitively compared to the benchmark of 90% and therefore below expectations. The benchmark was established late in the BP1 period, on the expectation that by BP2 we would have a Reactive Market in place. The development of that market was postponed in 2022 and has restarted in May 2023. This remains unchanged from Q2.

The Reactive Power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM).

The percentage of services delivered by non-competitive means in this quarter is similar to the previous quarter and will be in future quarters of 2023/24 as we re-establish the Reactive Power future market. We are now working on assessing the feasibility of implementing the proposed market design with a commitment to sharing a plan for how this will be implemented by the end of 2023/24.

The launch of the short- and long-term Voltage Pathfinders previously has proven that distribution network providers can also be effective to meet a transmission need. The long-term Mersey Pathfinder awarded two contracts to meet a need in this region: the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25 which will decrease the percentage of reactive power services procured and utilised through non-competitive means.

Unlike Q2, there was no need for any short-term requirements in Q3.

3. Constraints

Q3 2023-24 performance

Table 15: Constraints percentage of services procured on a non-competitive basis and spend.

Constraints		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWh	158	101	0	
	Volume procured non-competitively	GWh	155	101	0	
	Percentage of volume procured non-competitively	%	98%	100%	**N/A**	
	Year 1 benchmark	%	65%	65%	65%	65%
	Status	n/a	●	●	**N/A**	
Spend	Total spend	£m	4.9	0.8	0	
	Spend for volume procured competitively	£m	0.1	0	0	
	Spend for volume procured non-competitively	£m	4.8	0.8	0	

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5 or more higher than the annual procurement benchmark

The benchmark for Year 2 is 55%

Supporting information

In Q3, no constraint volume was procured due to low wind and no requirement to call upon the service. Therefore, there is no status applicable for Q3. Year-to-date we remain below expectations, with 98% of volume procured non-competitively, compared to the benchmark of 65%.

In BP2 we expected to be able to utilise the intertrip services more frequently across the B6 and future constraint boundaries if economic to do so and greater market liquidity. All remaining parties have been connected to the intertrip during December. We expect greater utilisation of this service in Q4 when wind is generally higher and shall continue to assess opportunities to use this service across the B6 boundary (dependant on system conditions) and will look to extend this to the East Anglia EC5 CMIS service when it becomes live.

Additionally, one optional Transmission Constraint Service for voltage control (through a Strike price option) contract was procured for the Southern region for services in December Q3. In December, no instructions were given as there were more economic options in the Balancing Mechanism.

Metric 2X Day-ahead procurement

This metric measures the percentage of balancing services procured at no earlier than the day-ahead stage, i.e. those procured at day-ahead or closer to real time. We report on total contracted volumes (mandatory and tendered) in megawatts (MWs). Expectations are set for all relevant services that are currently procured by the ESO and may be revised if new products are introduced.

Benchmarks are set based on expected product expirations, and expectations for new procurement volumes:

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, the ESO is required to procure at least 30% of services no earlier than day-ahead stage

Whilst the ESO set out the daily requirements for Day ahead procurement, when these requirements are not met through competitive day ahead tendering the outstanding requirement could be met through other means such as bi lateral agreements and mandatory markets.

The following services are included in the figures for this metric:

Day ahead: Short-Term Operating Reserve (STOR), Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response

Non-day ahead: Firm Frequency Response Monthly, Mandatory Frequency Response, Long Term STOR

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead.

Q3 2023-24 performance

Figure 13: Quarterly percentage of balancing services procured at no earlier than day-ahead

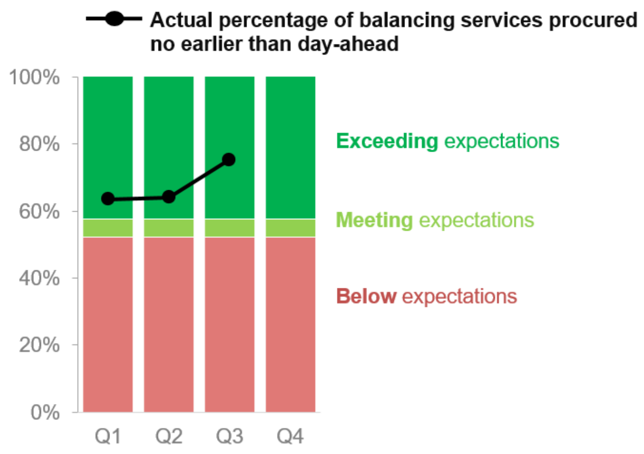


Table 16: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4
Total volume of balancing services procured	MW	12,447	13,209	11,608	
Volume procured no earlier than day-ahead	MW	7,910	8,463	8751	
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	64%	64%	75%	
Benchmark	%	55%	55%	55%	55%
Status	n/a	●	●	●	

Performance benchmarks:

- **Exceeding expectations:** 5% or more higher than annual day-ahead procurement benchmark
- **Meeting expectations:** within ±5% of the annual day-ahead procurement benchmark
- **Below expectations:** 5% or more lower than the annual day-ahead procurement benchmark

For year 2, the benchmark increases to 80%

Data content Information:	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

In Q3 75% of balancing services volume was procured no earlier than day ahead, compared to the benchmark of 55%, and therefore exceeding expectations.

The exceeding expectations performance for day ahead procurement of services is due to several factors across the markets. Over the past 12 months the response and reserve markets have matured, resulting in greater market liquidity and greater competition. Reducing volumes in non-day ahead service such as Dynamic Firm Frequency response (DFFR) as it is being phased out and these volumes are going into services procured at day ahead. DFFR was phased out in Q3.

Going forward we would expect to see this performance increase as legacy services are fully phased out and new services go live.

RRE 2Aii Balancing services procured in a non-competitive manner

This Regularly Reported Evidence measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2023, even if the contract terms were signed before (e.g. Mandatory Frequency Response). Figures are reported in GWh/GVARh for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

Q3 2023-24 performance

Figure 14: Volume and spend for non-competitive services for contracts

*Reactive volume is measured in GVARh and is not directly comparable to the other services measured in GWh but is included in the graph with this caveat.

Table 17: Volume and spend for non-competitive services

	Service	Unit	Q1	Q2	Q3	Q4
VOLUME	Frequency Response****	GWh	1,895	2,172	1,710	
	Reserve****	GWh	506	737	411	
	Constraints***	GWh	155	101	0	
	SO-SO trades	GWh	10,920	11,040	11,045	
	Net Transfer Capacity (NTC)	GWh	5,242	3,092	4639	
	Total Volume in GWH	GWh	**18,718**	**17,142**	**17,804**	
	Reactive (in GVARh)	GVARh	14,644	15,488	10,004	
SPEND	Frequency Response	£m	4.0	4.6	2.9	
	Reserve -	£m	8.7	11.9	6.6	
	Constraints	£m	4.8	0.8	0	
	SO-SO trades *	£m	0.06	0.2	0	
	Net Transfer Capacity (NTC)**	£m	0	0	0	
	Reactive	£m	76.1	67.9	45.8	
	Total spend	£m	**93.6**	**85.2**	**55.3**	

*SO-SO trades, trade volumes and costs for services provided to the ESO by another country's system operator have been included. Services provided by ESO to another country's System Operator are excluded.

**NTC cost has been updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 - Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in RRE 2Aii will not align with volume stated in Metric 2Ai. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from RRE 2Aii as per the agreed methodology.

Data content Information:	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are considering alternatives to MFR to reduce this volume in future.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time. The Optional Fast Reserve product will be phased out with the introduction of the new day ahead procured reserve products as they are introduced through 2024 and 2025.

Optional Fast Reserve is used for short-term frequency management outside contracted fast reserve windows e.g., periods where wind may have dropped unexpectedly or demand has increased more than anticipated. Note that day ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low.

Super SEL, which is now included as a Reserve service, is an active but optional contract that a number of generators can provide as a backup to other solutions. Super SEL has not been utilised since early 2022 and so we have reported 0GWh in this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

Constraints

There were no arming instructions throughout Q3 due to low wind and no requirement to call upon the service.

Additionally, one optional Transmission Constraint Service for voltage control (through a Strike price option) contract was procured for the Southern region for services in December Q3. In December, no instructions were given as there were more economic options in the Balancing Mechanism.

SO-SO Trades

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO.

EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CCB.

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity (NTC) and this reduction is defined as a non-frequency ancillary service.

Standard Licence Condition C28 requires that we procure non-frequency balancing services using market-based procedures. NTC is not procured through market-based procedures and therefore requires a derogation from this requirement. The procurement of NTC cannot be market-based due to technical parameters and the fact that alternative actions are not sufficient or economically efficient.

On 28 September, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTC's are our only way of guaranteeing system security in real time. As a result, they are as near to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

RRE 2B Diversity of Service Providers

This Regularly Reported Evidence (RRE) measures the diversity of technologies that provide services to the ESO in each of the markets covered by performance metric 2A (Competitive procurement). We report on total contracted volumes (mandatory and tendered) in megawatts (MWs) or megavolt amperes of reactive power (MVARs).

There are four services we report on:

- Frequency Response (MFR, sFFR, dFFR, DC, DM, DR, FFR Auction, EFR)
- Reserve (STOR, Fast Reserve)
- Reactive
- Constraints

Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

Methodology

<table>
<tr><th colspan="2">Product</th><th>Methodology</th></tr>
<tr><td rowspan="7">Frequency Response</td><td>Mandatory Frequency Response (MFR)</td><td>We report on contracted volumes for every unit. Figures only apply to a single day, not the whole month. For example, a 20MW MFR contract is only recorded as 20MW in the report, not as 600 MW (20MW x 30days).</td></tr>
<tr><td>Static Firm Frequency Response (sFFR)</td><td rowspan="2">We report on the highest volume for each unit that has contracted for a particular service block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Firm Frequency Response (dFFR)</td></tr>
<tr><td>Dynamic Containment (DC)</td><td rowspan="3">We report on the highest volume for each unit that has been contracted for a particular Electricity Forward Assessment (EFA) block for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Dynamic Moderation (DM)</td></tr>
<tr><td>Dynamic Regulation (DR)</td></tr>
<tr><td>Enhanced Frequency Response (EFR)</td><td>We report on contracted MW. This will not change from month to month unless a contract ends.</td></tr>
<tr><td rowspan="5">Reserve</td><td>Short Term Operating Reserve (STOR)</td><td>We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Super SEL (Footroom)</td><td>We report on contracted volumes for all contracts that are live for any part of the month.</td></tr>
<tr><td>Fast Reserve</td><td>We report on contracted volumes. We record the highest available volume for each unit for each month. Available volumes can change throughout the month for a unit. For example, a unit can be available at 60MW for 29 days in a month, and at 70MW for 1 day of the same month.</td></tr>
<tr><td>Quick Reserve</td><td rowspan="2">We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.</td></tr>
<tr><td>Slow Reserve</td></tr>
<tr><td rowspan="3">Reactive</td><td>Mandatory Reactive</td><td rowspan="3">We report on contracted volumes for every unit. Figures only apply to a single day and not the whole month. For example, a 20MW Reactive contract is only recorded as 20MW in the report, not as 600MW (20MW x 30days).</td></tr>
<tr><td>Stability Reactive</td></tr>
<tr><td>Synchronous Compensation</td></tr>
</table>

	Mersey & Pennine Pathfinder	
Constraints	Strike Price	We report on contracted volumes for all contracts that are live for any part of the month. Some are live for the whole month whereas others are live for part of the month. The highest available volume on a specific day for each unit for the relevant month is captured. The sum of those values is what we present in the monthly report.
	B6 Intertrip	

Firm Frequency Response Auction – this service is excluded as it ended in 2021-22.

ℹ	**Data content Information:**	Data consists of final settlement data for the first two months of the most recent quarter with the third month to be provided within the next submission of the report.

Figure 15: Total contracted volumes by service type for Q3

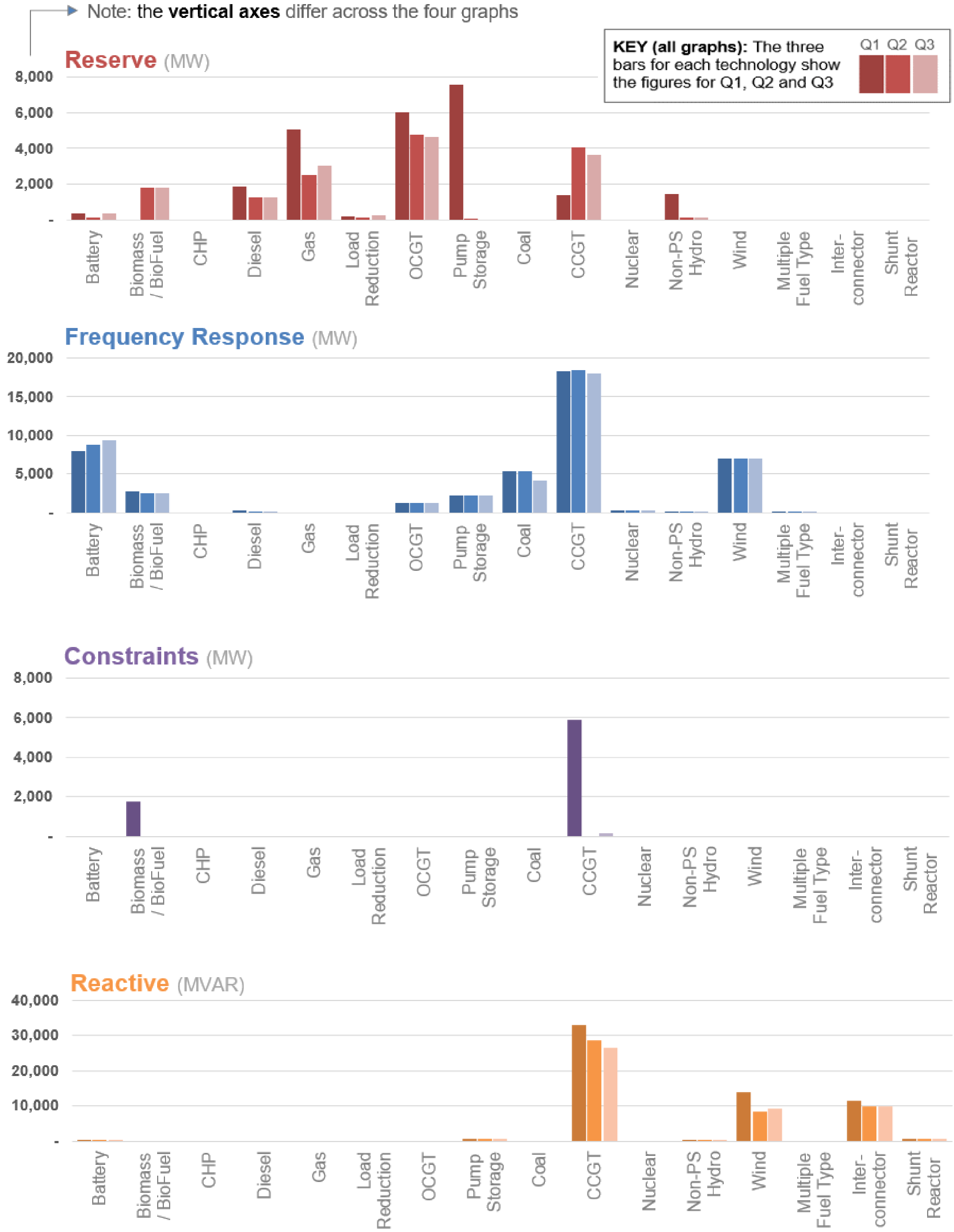


Table 18: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Q1	Q2	Q3
Total	8,017	8,022	8,022	5,038	5,105	4,793	5,009	5,029	5,184	24,062	14,936	15,222
Battery	134	134	134	40	24	88	135	105	125	401	152	365
Biomass/BioFuel	19	19	19	595	595	595	595	595	595	58	1,785	1,785
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	628	627	627	426	421	423	424	427	432	1,882	1,270	1,283
Gas	1,690	1,691	1,691	910	831	773	1,023	1,034	984	5,073	2,514	3,041
Load Reduction	70	70	70	54	55	52	69	87	101	210	161	257
OCGT	2,001	2,003	2,003	1,497	1,762	1,485	1,535	1,562	1,578	6,008	4,744	4,675
Pump Storage	2,516	2,519	2,519	100	-	-	-	-	-	7,554	100	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	465	466	466	1,416	1,417	1,227	1,228	1,219	1,219	1,397	4,060	3,666
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	490	490	490	-	-	150	-	-	150	1,470	150	150
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	-	9	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Q1	Q2	Q3
Total	15,161	15,436	15,203	15,501	15,324	15,467	15,451	15,673	14,057	45,800	46,292	45,181
Battery	2,596	2,767	2,695	3,017	2,820	2,956	2,960	3,162	3,254	8,058	8,793	9,376
Biomass/BioFuel	957	937	837	837	837	837	817	837	837	2,731	2,511	2,491
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	112	112	56	36	56	56	56	56	54	280	148	166
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	443	443	443	443	443	443	443	443	362	1,329	1,329	1,248
Pump Storage	728	728	728	728	728	728	728	728	728	2,184	2,184	2,184
Coal	1,782	1,782	1,782	1,782	1,782	1,782	1,782	1,782	650	5,346	5,346	4,214
CCGT	6,024	6,148	6,148	6,148	6,148	6,155	6,155	6,155	5,662	18,320	18,451	17,972
Nuclear	92	92	92	92	92	92	92	92	92	276	276	276
Non-PS Hydro	70	70	70	70	70	70	70	70	70	210	210	210
Wind	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	2,343	7,029	7,029	7,029
Multiple Fuel Type	14	14	9	5	5	5	5	5	5	37	15	15
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-

Constraints

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Q1	Q2	Q3
Total	2,300	3,605	1,795	-	-	-	-	-	-	7,700	-	-
Battery	-	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	-	-	-	-	-	-	1,785	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	1,705	3,010	1,200	-	-	-	-	-	200	5,915	-	200
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Oct-23	Nov-23	Dec-23	Q1	Q2	Q3
Total	19,921	19,921	19,921	16,174	16,174	16,174	15,702	15,839	15,747	59,763	48,522	47,288
Battery	32	32	32	16	16	16	49	65	49	96	48	163
Biomass / BioFuel	-	-	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	235	235	235	235	235	235	235	235	235	705	705	705
Coal	-	-	-	-	-	-	-	-	-	-	-	-
CCGT	11,021	11,021	11,021	9,579	9,579	9,579	8,832	8,832	8,832	33,063	28,737	26,496
Nuclear	-	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	93	93	93	72	72	72	72	72	72	279	216	216
Wind	4,573	4,573	4,573	2,813	2,813	2,813	3,055	3,176	3,100	13,719	8,439	9,331
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-	-
Interconnector	3,767	3,767	3,767	3,259	3,259	3,259	3,259	3,259	3,259	11,301	9,777	9,777
Shunt Reactor	200	200	200	200	200	200	200	200	200	600	600	600

Supporting information

The commentary below is similar to previous reports as the diversity of providers that provide balancing services didn't change significantly through BP1 and is not expected to change much in BP2 unless otherwise stated.

Frequency Response

Frequency services are delivered by providers who have a Mandatory Services Agreement (MSA) agreement or who are awarded contracts through a competitive tendering process (which includes the daily auctions). Mandatory Frequency Response is primarily provided by providers with MSA registered transmission connected Units. For frequency response procured through competitive tendering the unit base is a mix of BM and Non-BM, primarily distribution connected, however we are starting to also see transmission connected storage assets that are providing frequency services. There is a continued growth in MWs from batteries providing tendered frequency services, with this asset type now making up the vast majority of the MWs provided by frequency services procured through competitive tendering.

Reserve

Procurement volumes and technology mix in Q3 remain consistent with historical STOR data.

Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the BM. The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. The addition of the Peak Gen shunt reactor service that went live in Q1 2022-23 has further diversified the type of providers. In January 2022 we also awarded contracts to meet reactive needs from an offshore windfarm in the Pennines region due to commence in 2024-25.

Constraints

Constraint costs occur when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. Historically, this service has been limited to the providers that are connected to the transmission network and by requiring providers to change their MW generation levels. The Constraint Management Pathfinder reduces the actions required by the ENCC to manage the constraint across the B6 boundary.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

This Regularly Reported Evidence (RRE) shows the accuracy of Balancing Services Use of System (BSUoS) forecasts used to set industry charges against the actual outturn charges.

The BSUoS charge (£/MWh) is now based upon a fixed tariff that was published in January 2023. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) were forecast for the year ahead, and two 6-month tariffs were set to cover the 2023/24 charging year.

We continue to forecast balancing costs monthly and measure our performance against this forecast as it remains an important metric to support the fixed tariff methodology, by being the main component of the fixed BSUoS tariff. The BSUoS cost forecast (costs rather than what is charged against the fixed tariff) is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then the actual costs for that month would be lower than the forecast predicted, provided the actual volume is at or above the estimate (and vice versa).

December 2023-24 performance

Figure 16: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

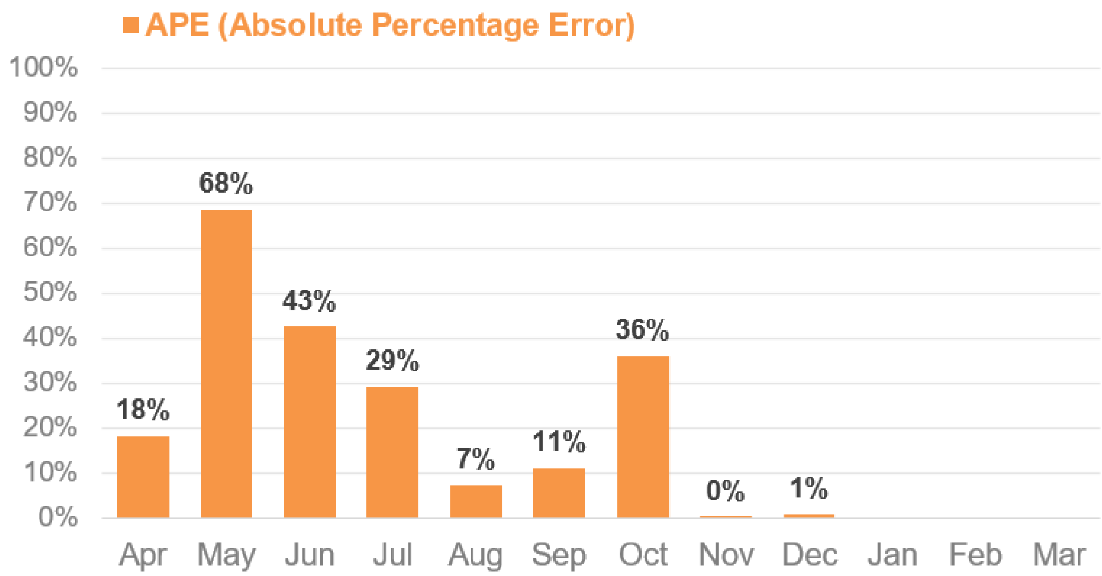


Table 19: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[5] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4	12.8	16.5	10.5	10.6			
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4	10.6	10.5	10.6			
APE (Absolute Percentage Error)[6]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**	**36.0**	**0.0**	**0.7**			

[6] Monthly APE% figures may change with updated settlements data at the end of each month. Therefore, subsequent settlement runs may impact the end of year outturn.

Supporting information

December Performance:

Actuals out-turned in line with forecast for December 2023, with an Absolute Percentage Error of 0.7% Both cost and volume out turned slightly above forecast, bringing the £/MWh outturn in line with our month-ahead forecast.

Costs:

December outturn costs were around the 55th percentile of the forecast produced at the beginning of November. Despite a 30% decrease in the average wholesale electricity price between the November forecast for December (£101/MWh) and December outturn (£67/MWh), this was offset by a 11% increase in the proportion of demand met by renewable generation (31% in November forecast for December and 42% in December outturn).

Volumes:

December actual volume was slightly above the November forecast.

Forecast for December made at the start of November: 25.1TWh

Outturn volume for November: 25.6TWh

Notable events during December 2023

We published our assessment and conclusions from Phase 4 of our Net Zero Market Reform (NZMR) programme

Established in 2021, our NZMR programme aims to examine the changes to current GB electricity market design that will be required to achieve the Government's objective of full decarbonisation of the electricity system by 2035, subject to security of supply and cost-effectiveness for consumers.

In December 2023, ESO published its Phase 4 report with its conclusion on investment policies, including potential reform of the EMR schemes (i.e. Contracts for Difference and Capacity Market) and their packaging with wholesale market reforms. This report was the culmination of analysis undertaken throughout 2022 and 2023, including a commissioned analysis by Baringa, published in February 2023, and stakeholder input that was gathered through bilateral meetings, meetings of ESO's Market Advisory Council, the ESO's Market Forum events (September 2022, November 2023) and a webinar dedicated to sharing the conclusions of the investment analysis (July 2023, which attracted over 400 attendees).

Phase 4 built upon the work of previous phases, particularly that of Phase 3, which focussed on the operational elements of market design relating to locational signals and the dispatch and scheduling process. ESO continues research and analysis on centralised and decentralised scheduling, as well as co-optimisation of energy and ancillary services, which we will be engaging on in Feb 2024.

Since the Government launched its Review of Electricity Market Arrangements (REMA) in July 2022, ESO has been feeding NZMR analysis into DESNZ's own analyses in most REMA areas through regular bilateral meetings. This ongoing work has drawn upon expertise across ESO, including in system operation, market development, market monitoring, supply and demand forecasting, system modelling and delivery of the EMR schemes.

Early Competition Update

On 14 December, we held a webinar to update stakeholders on progress towards introducing early competition. This covered updates on the strategic position from government and the passing of the Energy Act 2023. We also set out some proposed changes to the early competition model following updates to network planning processes as part of the introduction of the Centralised Strategic Network Plan (CSNP). Furthermore, we set out our plans for working closely with Ofgem over the next year in order to launch the first competition during 2024.

Reserve Reform Update

On 19 December we held a webinar to update industry on the current status of the Reserve Reform project. Reserve Reform had been delayed twice because of reprioritisation due to world events and system challenges. This webinar ran through the plan and new timelines for delivery of the new Reserve Services (Quick & Slow), we had over 100 attendees for the webinar with good feedback and questions on the content delivered.

The delivery of Reserve Reform will be a phased approach, we plan to commence the procurement of Positive and Negative Quick Reserve in the second half of 2024 based on the capabilities of our new and legacy IT systems. In phase 1 we propose that Quick Reserve participation is enabled through our existing BM legacy systems in combination with the new Open Balancing Platform (OBP) multi-dispatch tool, for this phase providers will need to be or become Balancing Mechanism Units to provide the service. In parallel we will continue to develop our IT systems, enabling functionality to dispatch and monitor non-BM units, for delivery of Quick Reserve phase 2 in the second half of 2025. Slow Reserve will be delivered alongside phase 2 of Quick Reserve. We will continue to engage throughout 2024 on the designs of our new Reserve Services and look forward to this continued engagement with industry.

Role 3
(System insight, planning and network development)

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

- England and Wales: National Grid Electricity Transmission (NGET)
- Central and Southern Scotland: SP Transmission (SPT)
- North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process is running we will report:

- The number of standard offers issued within 3 months.
- For two-step offers, the number of (one-step) offers issued within 3 months.
- the number of two-step offers issued within nine months, after counter signature of the step one offer;
- and the number of any connection offers that took longer than the above timeframes.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Table 20: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	162	28	30		
	(One-step) Within 3 months	23	154	285		
	(Two-step) Within 9 months*	0	0	0		
	Longer than the above timeframes	0	0	0		
	Total	**185**	**182**	**315**		
SPT (Scotland)	(Standard offer) Within 3 months	77	104	83		
	Longer than 3 months	0	4	1		
	Total	**77**	**104**	**84**		
SHET (Scotland)	(Standard offer) Within 3 months	95	89	103		
	Longer than 3 months	0	2	0		
	Total	**95**	**89**	**103**		
TOTAL	Within 3 months	**357**	**369**	**501**		
	Longer than 3 months	**0**	**6**	1		
	Total	**357**	**375**	**502**		

* after counter signature of the step one offer

Figure 17: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2023) vs Q2 (30 Sep 2023) vs Q3 (31 December 2023)

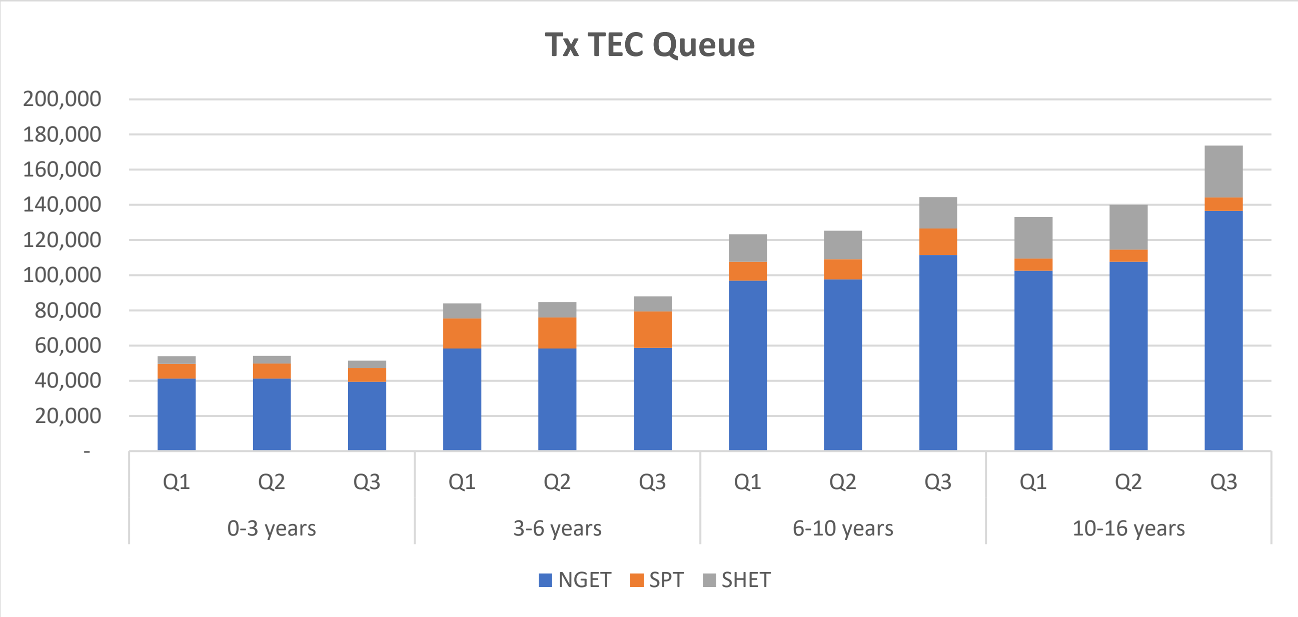
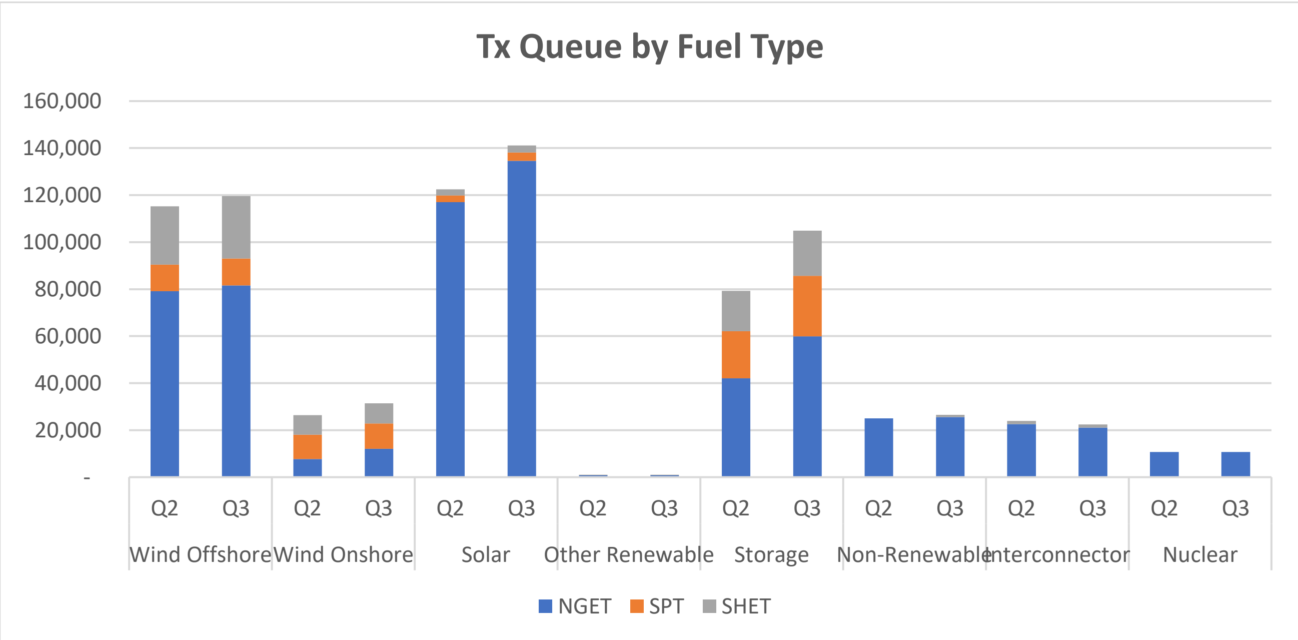


Table 21: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total
NGET	MW	39,508	58,777	111,403	136,545	**346,233**
SPT	MW	7,770	20,658	15,185	7,645	**51,259**
SHET	MW	4,151	8,615	17,764	29,511	**60,042**
Total	MW	**51,430**	**88,050**	**144,353**	**173,701**	**457,534**

Figure 18: Connections queue in MW by technology type (31 Dec 2023)



Note: Since the Q1 report, the fuel type classifications have changed in line with other regulatory reporting. Therefore we are unable to show the change at technology level compared to Q1. From Q3 onwards we will be able to show change compared to the previous quarter.

Figure 19: Connections queue in MW by technology type (31 Dec 2023)

Host TO	NGET	SPT	SHET	Total
Wind Offshore	81,622	11,356	26,568	**119,546**
Wind Onshore	12,131	10,638	8,635	**31,405**
Solar	134,560	3,586	3,038	**141,185**
Other Renewables	733	-	277	**1,010**
Storage	59,970	25,678	19,281	**104,928**
Non-Renewable	25,626	-	910	**26,536**
Interconnector	21,054	-	1,400	**22,454**
Nuclear	10,680	-	-	**10,680**
TOTAL	**346,376**	**51,259**	**60,109**	**457,744**

Supporting information

Timeliness of connection offers

Application volumes continue to increase in comparison with 2022/23 and this is reflected in the number of offers being sent out across all three TOs.

One offer has been sent outside of CUSC timescales in Q3, this was a post-interactivity offer and Ofgem have been made aware. Further to this, three extensions have been requested from Ofgem in respect of applications where clock start has been identified late by the ESO. Assuming the extensions are granted these delayed offers will be reported on in the Q4 figures when the offers are sent.

Connections queue

The Connections queue continues to increase, moving from 404GW at the start of Q2 to 457GW at the end of the quarter. The vast majority of this increase is due to new connection applications from battery storage developers. A large increase in connection dates for the 6-10 year and 10-16 year periods can be seen, which is in line with average connection timescales of 10 years in E&W and 7 years in Scotland.

CUSC modification CMP376 (Inclusion of Queue Management process within the CUSC) was approved and implemented in November 2023. This introduces queue management milestones into connection contracts, and allows the ESO to terminate contracted projects which are not progressing against agreed milestones. This is a significant step towards being able to reduce the size of the overall queue and remove stalled projects.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to by TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

Table 22: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4	Total
NGET	Total Step 1 offers signed	1	72	224		
	Number right first time	1	70	222		
	Percentage right first time	**100%**	**99%**	**99%**		
	Total Full / Step 2 offers signed	222	147	38		
	Number right first time	182	121	28		
	Percentage right first time	**95%**	**93%**	**92%**		
SPT	Total connection offers signed	50	48	65		
	Number right first time	38	42	55		
	Percentage right first time	**88%**	**98%**	**97%**		
SHET	Total connection offers signed	46	63	52		
	Number right first time	36	48	36		
	Percentage right first time	**91%**	**95%**	**90%**		
TOTAL	Total connection offers signed	319	330	379		
	Number right first time	257	281	341		
	Percentage right first time	**93%**	**95%**	**95%**		

Table 23: Connection offer that needed reissuing by reason

Area	**One-step** connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	18	14	6		
	ESO driven	12	11	4		
	TO driven	24	13	5		
	Total	**40***	**28***	**12***		
SPT	Customer driven	6	5	7		
	ESO driven	6	1	2		
	TO driven	3	4	2		
	Total	**12***	**6***	**10***		
SHET	Customer driven	4	7	11		
	ESO driven	4	3	5		
	TO driven	4	7	6		
	Total	**10***	**15***	**16***		
TOTAL	Customer driven	28	26	**24**		
	ESO driven	22	15	**11**		
	TO driven	31	24	**13**		
	Total	**62***	**49***	**38***		

* Please note that re-offers can be driven by more than one factor. Therefore the totals can be lower than the sum of the figures for each reason

Supporting information

Numbers of re-offers are spread across the TOs relative to the number of offers signed within the period, and the drivers for the re-offers are fairly evenly distributed with ESO driven re-offers coming in a little lower than the others.

There are a variety of reasons leading to an offer being re-issued such as amendments to appendices, charging statements and offer documents following post-offer discussions.

The number of ESO driven re-offers directly affects our performance percentage, which is calculated by looking at the number of offers right first time not due to an ESO re-offer. Re-issued offers and the reasons for them are continuously reviewed.

Notable events during December 2023

We set out our final recommendations for long-term connections reform

Following a year-long process conducted with industry and wider stakeholders to identify the longer-term reforms needed to improve the connections process, we've set out our final recommendations.

Our new "First Ready, First Connected" approach, supports projects that can deliver at speed and ensures the connections queue can no longer be bogged down by so called "zombie projects". Under our proposals, we'll implement a new connections process based on an early application window (with an indicative frequency and duration of 12 months) and two formal gates to track project progression and hold developers to account.

Gate 1 will provide offers based on a co-ordinated network design connection date. Gate 2 will be used to determine queue position for projects within the application window and accelerate viable and robust priority projects. The reformed process will apply to all new generation, interconnector and demand connection applications, as well as relevant projects that modify their connections application after the go live date for the new process.

We plan to implement these changes by the start of January 2025, subject to the delivery of relevant modifications to existing industry codes.

We'll also create a new Connections Process Advisory Group from January 2024, with an independent chair, to enable industry to steer the detailed design and code modifications within the parameters set out our final recommendations. This advisory group will also report to the Connections Delivery Board being established by Ofgem and the Government.

These reforms will deliver a future proofed solution and facilitate future network coordination.

These reforms build on our existing five-point plan of short-term reforms and will help deliver the Connections Actions Plan recently published by the Government and Ofgem.

Our five-point plan is already speeding up connections and will potentially remove around 80GW of projects from the existing queue, freeing up space for projects that can meet their connections milestones.

Launch of Voltage 2026 Network Services Procurement tender

On 19 December 2023, we launched the invitation to tender (ITT) for the Voltage 2026 NSP tender.

This follows the Expression of Interest (EOI) stage in October 2023 where the market was were invited to express their interest in participating in the tender.

This Voltage 2026 tender will allow ESO to identify potential solutions to meet reactive power requirements in two regions in England from 2026 onwards, and represents the third Voltage "Pathfinder" type procurement that the ESO has run.

More information about the Voltage 2026 tender can be found here: https://www.nationalgrideso.com/industry-information/balancing-services/pathfinders/noa-voltage-pathfinder

Launch of first Stability Y-1 Market tender

On 20 December 2023, we launched the invitation to tender (ITT) for the first tender of the Mid-Term (Y-1) Stability Market, which is focused on securing stability services between 2025 and 2026.

Earlier in 2023, we hosted a conclusion webinar about which brought the Stability Market Design innovation project to a close, summarising that the Stability Market will be set up with three procurement routes, long-term (Y-4), mid-term (Y-1) and short-term (D-1).

During this webinar we also confirmed that we will start implementing the enduring Stability Market with the Mid-Term (Y-1) Market, which is focused on securing stability through one-year contracts, one-year prior to the point in time the service is required.

The launch of the ITT for this first tender in the Mid-Term (Y-1) Stability Market follows the Expression of Interest (EOI) stage and Consultation held earlier in October 2023, and the Request for Information in July 2023.

More information about the Stability Market, and the initial Stability Market Design project, can be found here:

- https://www.nationalgrideso.com/industry-information/balancing-services/stability-market
- https://www.nationalgrideso.com/industry-information/balancing-services/stability-market/mid-term-y-1-stability-market
- https://www.nationalgrideso.com/future-energy/projects/stability-market-design