ESO RIIO2 Business Plan 2 (2023-25)

July 2024-25 Incentives Report

23 August 2024

ESO

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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 17^{th} 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 July we successfully delivered the following notable events and publications. We provide further detail on each of these under the role sections:

- On 10 July, we published the latest Power Responsive Annual Report. It reflects on policy, regulatory, and market developments in 2023 and provides insights into demand side flexibility participation. The report aims to support stakeholders in navigating industry changes and fostering the growth of demand side participation in flexibility markets. It covers recent initiatives, demand side metrics, and future outlook, with contributions from Everoze, DESNZ, Ofgem, and Kraken.
- On 17 July, the REMA Dispatch & Balancing team held a webinar to discuss scheduling and dispatch options within DESNZ's REMA Programme. They presented potential dispatch models, outlined counterfactual and counterfactual+ scenarios, and facilitated breakout group discussions to gather industry feedback. Further information can be found on the provided link.
- On 15 July, we launched the annual Future Energy Scenarios (FES) publication, which provides credible pathways to decarbonise the energy system in alignment with the UK Government's 2050 net zero initiative. This year's FES introduces a new framework with three net zero pathways and a 'Counterfactual' scenario. The publication includes the full suite of FES 2024 documents and recordings of the launch webinars, which can be accessed on our website.

Summary of Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) for July 2024.

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£123m vs benchmark of £173m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 528MW vs indicative benchmark of 538MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.43% vs indicative benchmark of 4.02%	●
Metric 1D	**Short Notice Changes to Planned Outages**	0 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	●
RRE 1E	**Transparency of Operational Decision Making**	96.3% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of ESO actions**	9.27gCO_2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds. 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	1 planned and 0 unplanned system outages	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 47%	N/A

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

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

Hannah Kruimer
Interim Head of Regulation

Role 1 (Control Centre operations)

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 was 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 was 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 has been established between historic non-constraint costs and the historic wholesale day ahead price of electricity.

iv. Ex-post actual data input 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 = 62.25 + (Day Ahead baseload x 0.478)
Constraint costs = -33.49 + (Day Ahead baseload x 0.39) + (Outturn wind x 23.51)

Benchmark (Total) = 28.76 + (Day Ahead baseload x 0.87) + (Outturn wind x 23.51)

**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 panel. Details of how to sign up and recordings of previous meetings are available here.

July 2024-25 performance

Figure: 2024-25 Monthly balancing cost outturn versus benchmark

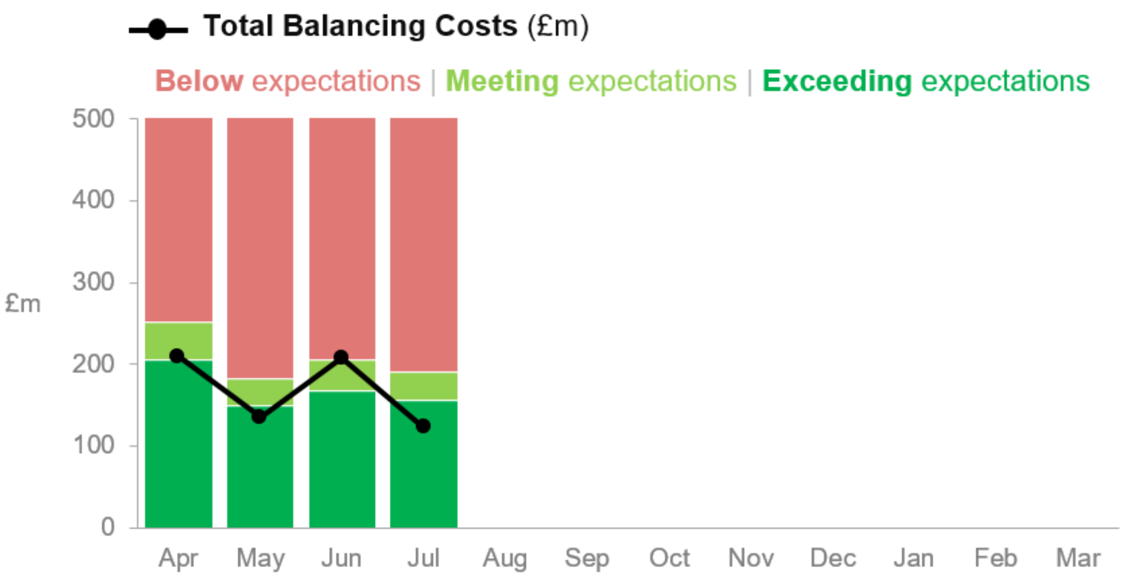


Table: 2024-25 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	6.3	3.2	3.9	3.5									16.9
Average Day Ahead Baseload (£/MWh)	59	72	76	71									n/a
Benchmark	228	167	187	173									775
Outturn balancing costs[1]	**209**	**135**	**208**	**123**									**675**
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

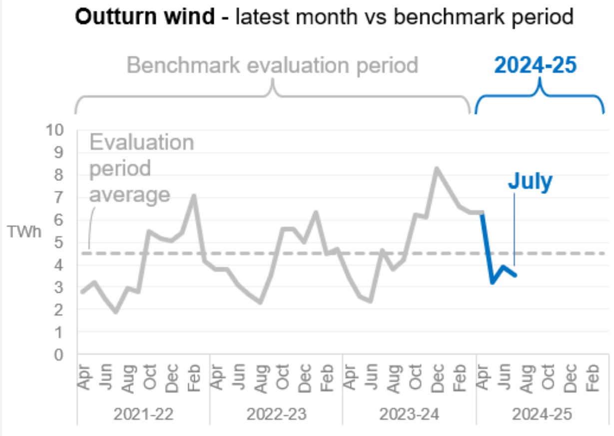
Supporting information

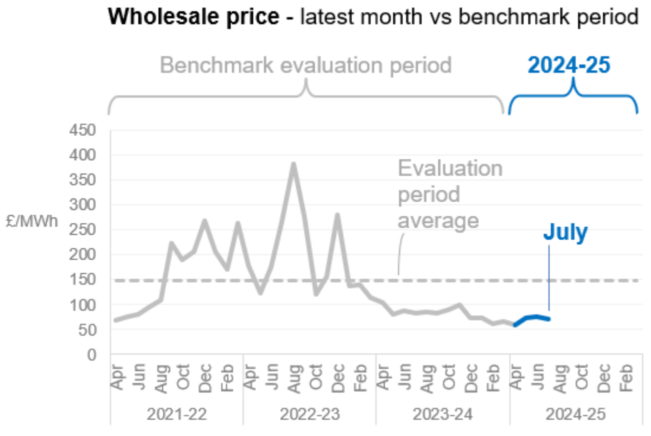
This month's benchmark

The July benchmark of £173m is £14m lower than June 2024 (£187m) and reflects:

- An **outturn wind** figure of 3.5TWh that is lower than the average during the benchmark evaluation period (the last three years, where the average wind outturn is 4.5TWh) and is slightly lower than last month's figure (June 2024).
- An average monthly **wholesale price** (Day Ahead Baseload) that remains low compared to the benchmark evaluation period, and £5/MWh lower than last month's figure (June 2024).

The slight decrease in both wind outturn and wholesale price contribute to the decrease in the overall benchmark compared to last month.





[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.

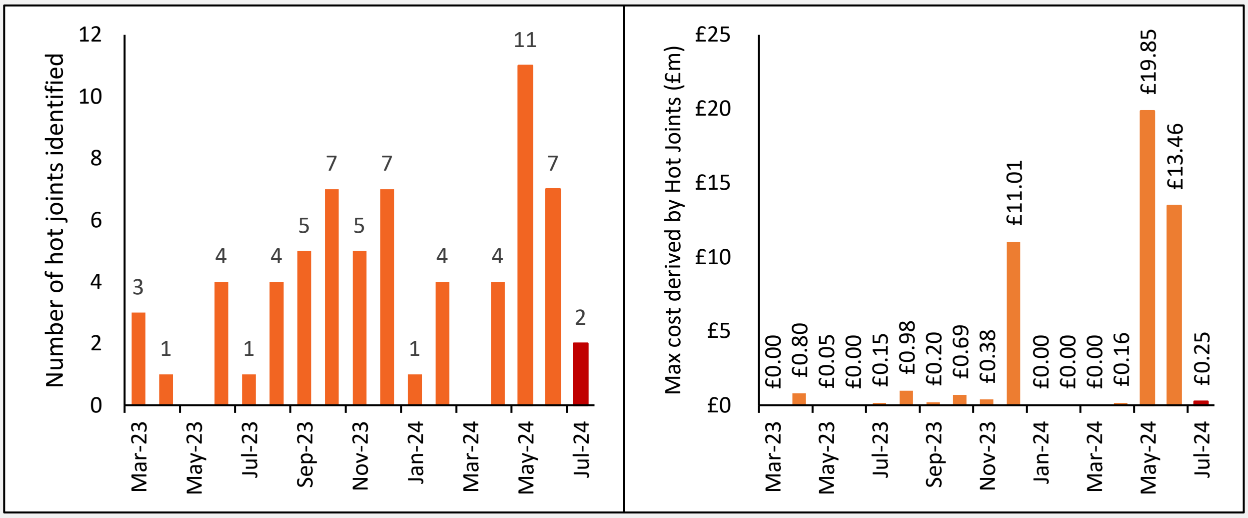
July Performance

July's total balancing costs were £123m which is £50m (~29%) below the benchmark of £173m, and therefore performance is exceeding expectations. July saw a 10% decrease in overall wind generation compared to June. In England and Wales wind outturn saw a slight increase of 4% while wind outturn in Scotland, which had contributed to higher costs in June, decreased 24%. This contributed to a significant drop in constraint volumes which drove constraint costs to their lowest July cost in 5 years. The volume weighted average price for bids decreased by £29/MWh compared to last month (from £93.3/MWh to £64.4/MWh), and the volume weighted average offer price fell £8/MWh (from 113.6/MWh to £104.6/MWh).

July also saw the lowest cost so far of this financial year and fell significantly (£113m) below July 2023 costs (£236m). Lower wind generation and slightly lower wholesale prices have contributed to the drop in costs compared to June 2024 and July 2023. Total constraint volumes and costs decreased by 431 GWh and £77m compared to the previous month. Non-constraint volume and costs also fell by 236 GWh and £6m respectively.

The total savings from outage optimisation were £238.6m in July 2024, this represents an increase of £166m relative to June this year (£72.6m). The action that yielded the greatest value was related to an outage rescheduling request for a 275 kV circuit in Scotland due to considerable drops in the transfer capacity of two boundaries in the area. Taking the outage as initially planned would have also increased the impact of a 400 kV double circuit trip affecting the operation of the region. Cost savings for this action are estimated to be roughly £70.2m.

We continue to monitor the occurrence of hot joints in the system and their potential cost impact. In July two hot joints were identified in the South East. Both were resolved during the first week of August with no significant cost impact identified.



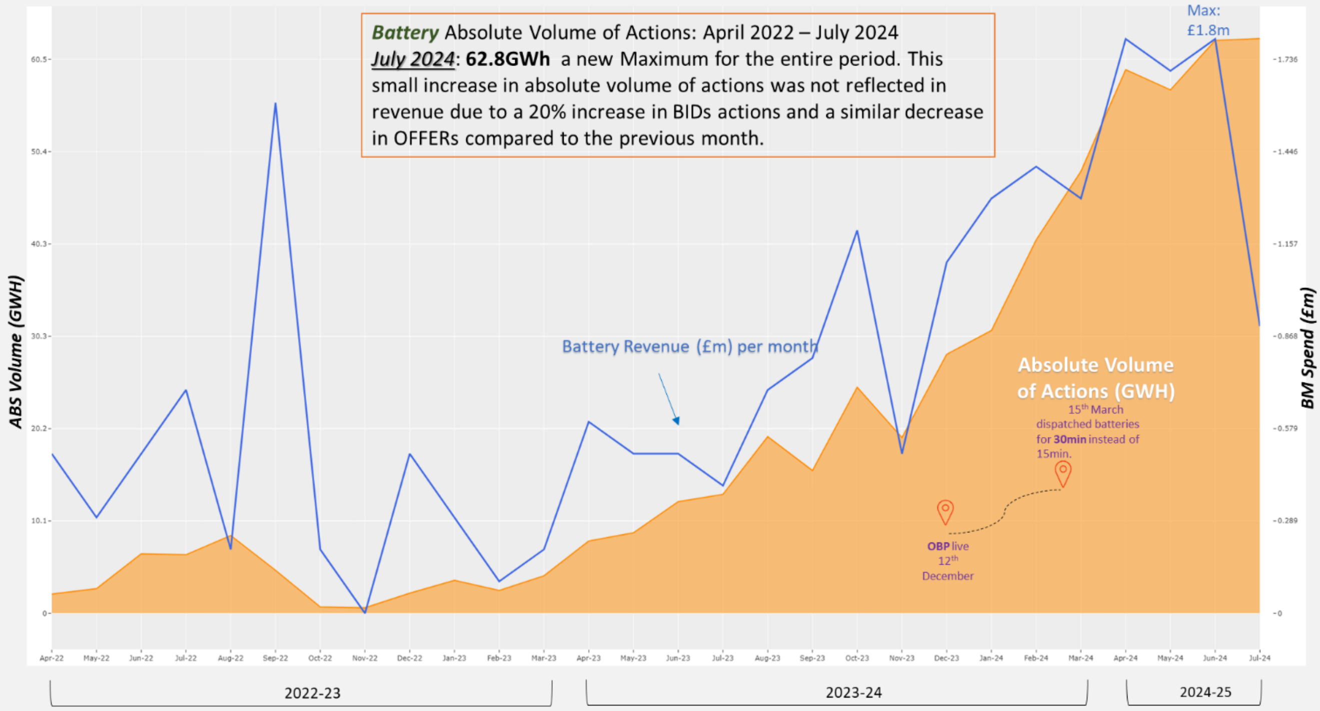
The Trading team were able to make a total saving of £23.9 million in July through trading actions as opposed to alternative BM actions, representing a 57.8% decrease on the previous month but is similar to monthly savings seen earlier in the year. Trades were conducted for downwards regulation, to help manage constraints and provide margin. This was coupled with trades to help manage constraints in South East England (ESTEX), which were preferred against more expensive wind bids and avoid the need to take emergency actions. However, constraint costs have been significantly reduced over the ESTEX boundary due to the interconnector Britned being on an ongoing outage. Voltage savings for this month were primarily comprised of savings from the South of England (VSCENTRAL). The day with the greatest spend on trades was on 18 July at a cost of £0.82 million with the greatest component being for margin.

As discussed in December's incentives report, 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. Since then, our ability to dispatch a greater number of typically smaller BMUs within a settlement period has increased. This has unlocked greater capability to dispatch batteries in the Balancing Mechanism.

July had a small increase in battery dispatch absolute volume (63 GWh). This illustrates our commitment to maximising the flexibility of energy offered by battery storage and small BMUs over the last year.

Monthly Absolute Volume of actions and spend for Batteries in the Balancing Mechanism

April 2022 to July 2024



Breakdown of costs vs previous month

Balancing Costs variance (£m): July 2024 vs June 2024

		(a) Jun-24	(b) Jul-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	5.9	1.7	(4.2)	
	Operating Reserve	6.0	5.1	(0.9)	
	STOR	3.4	3.8	0.4	
	Negative Reserve	0.2	0.2	0.0	
	Fast Reserve	15.8	15.5	(0.3)	
	Response	15.0	13.5	(1.5)	
	Other Reserve	2.5	2.5	0.0	
	Reactive	10.7	11.7	1.0	
	Restoration	2.2	2.9	0.8	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	1.9	0.8	(1.1)	
Constraint Costs	Constraints - E&W	44.4	14.8	(29.6)	
	Constraints - Cheviot	1.6	4.6	3.0	
	Constraints - Scotland	68.4	32.3	(36.1)	
	Constraints - Ancillary	0.7	0.6	(0.1)	
	ROCOF	8.8	7.7	(1.1)	
	Constraints Sterilised HR	18.4	5.4	(13.1)	
Totals	Non-Constraint Costs - TOTAL	63.5	57.8	(5.7)	
	Constraint Costs - TOTAL	142.3	65.4	(76.9)	
	Total Balancing Costs	**205.8**	**123.2**	**(82.6)**	

As shown in the total rows from the table above, constraint costs reduced by £76.9m and non-constraint costs decreased by £5.7m, resulting in an overall decrease of £82.6m (rounded to £0.1m) compared to June 2024.

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

- **Constraint-Scotland & Cheviot***: The constraint costs in Scotland and Cheviot decreased by £33.1m in part due to significantly lower absolute curtailed volume of actions by 297 GWh than June 2024.

- **Constraint-England & Wales***: The constraint cost in England & Wales decreased by £29.6m although the absolute volume of actions increased by 130 GWh. There was a slightly higher proportion of bids gas generators compared to last month and overall lower volume weighted average price for bids and offers which is likely to have contributed to this trend.
- **Constraint Sterilised Headroom***: £13.1m decrease due to a reduction of 722 GWh total volume of replacement energy. This is in line with the decrease in constraint volumes in Scotland.

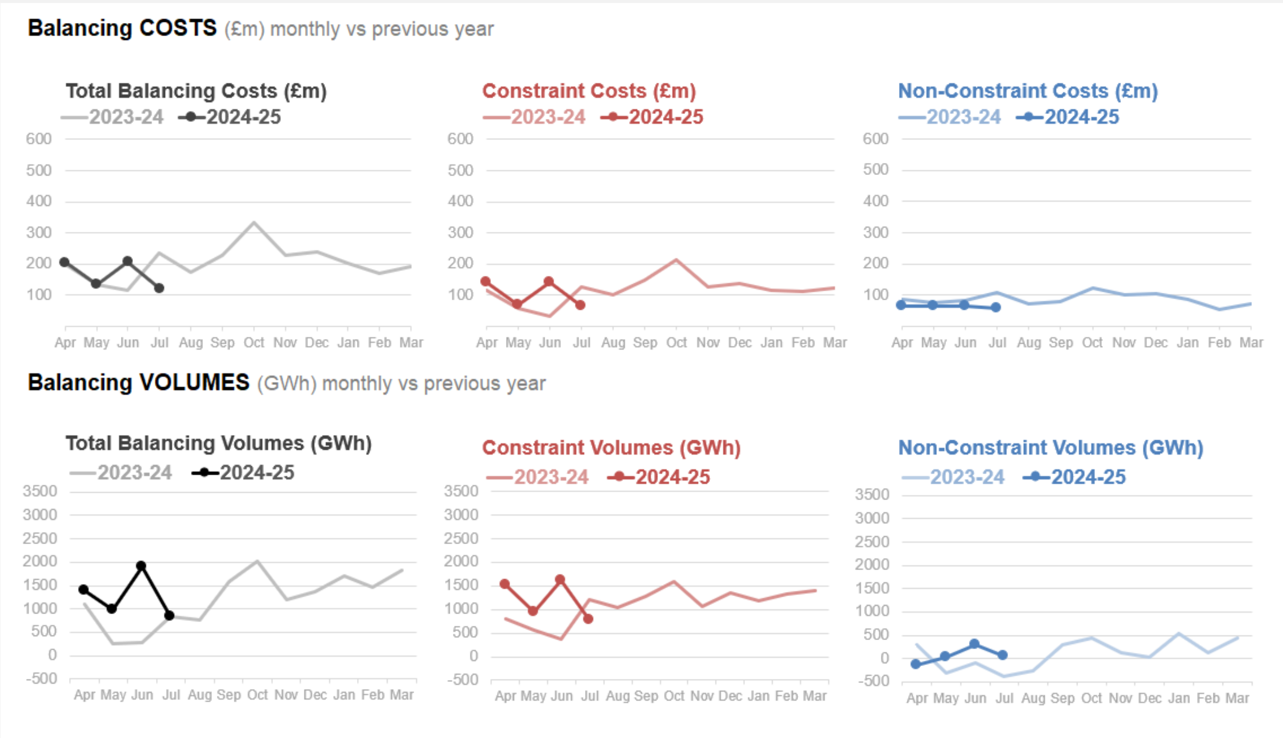
*This month saw a decrease in the volume weighted average price for bids following a slightly reduced electricity price.

Non-constraint costs*: The main driver of the variance this month is:

- **Energy Imbalance**: reduced by £4.2m, in line with a 11 GWh decrease in the absolute volume of actions.
- **Operating Reserve**: £0.9m lower in cost following a reduction of 236 GWh reserve required to secure the system.
- **Fast Reserve**: £0.3m decrease due to a 13 GWh decrease in volume.
- **Response**: £1.5m reduction despite an increase of 19 GWh in the absolute volume of actions.
- **Reactive**: £1.0m increase due to a minor increase in the volume average price from £3.4/MVAr to £3.8/MVAr compared to last month.

*Excluding the volume of actions from ancillary services as not yet quantified at the time of writing this report.

Constraint vs non-constraint costs and volumes



In summary, the total Constraint costs and non-constraint costs are featured below.

Constraint costs

Compared with the same month of the previous year:	We observe a decrease of £61.2m in constraint costs compared to July 2023, due to a 493 GWh reduction in volume of constraint actions.

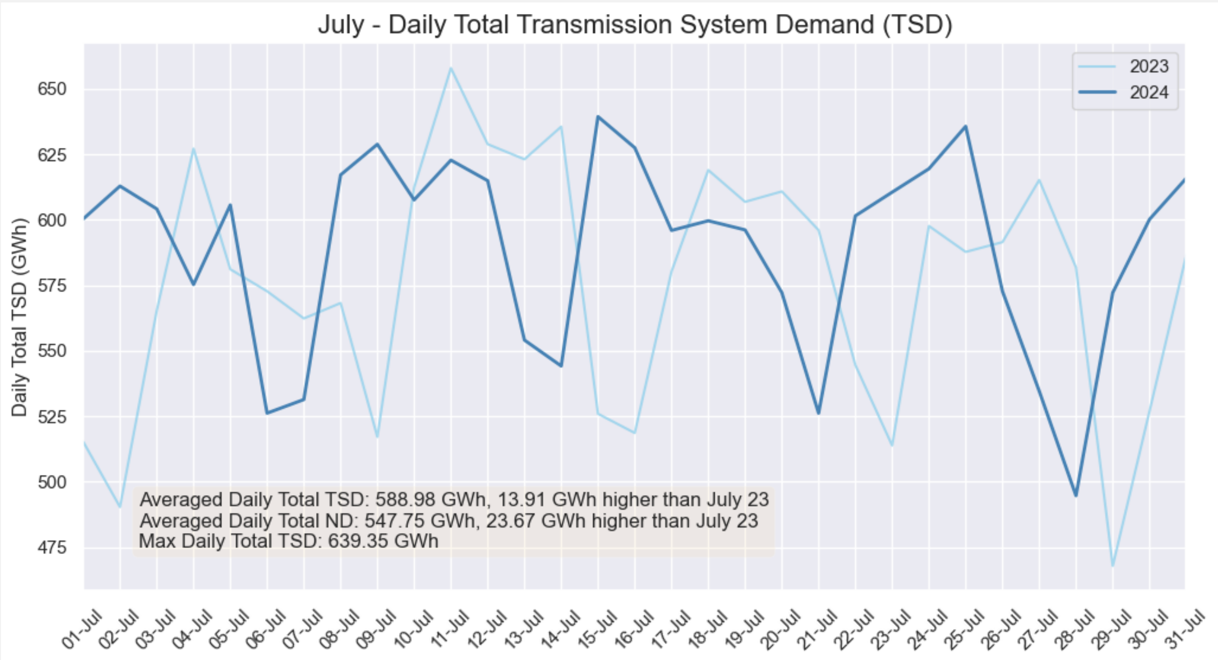
Compared with last month:	Constraint costs decreased by £76.9m compared to June 2024, due to a 431 GWh reduction in volume of constraint actions, in line with a reduction in wind generation, particularly in Scotland.
Non-constraint costs**	
Compared with the same month of the previous year:	Non-Constraint costs were £52.6m lower than in July 2023 due to: • Slightly lower average wholesale prices* • The total volume has lowered from –390 GWh last July to 53 GWh this July, resulting in an increase of 443 GWh in net volume of actions and a decrease of 337 GWh in absolute volume of actions.
Compared with last month:	Non-Constraint costs were £5.7m lower than June 2024, the total volume reduced to 53 GWh in July, lower than 289 GWh in June as shown in the chart above, resulting in a decrease of 236 GWh in volume of actions.

* Average wholesale price for July 24: £71/MWh compared to £82/MWh for July 23.

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

July daily Transmission System Demand (TSD*)

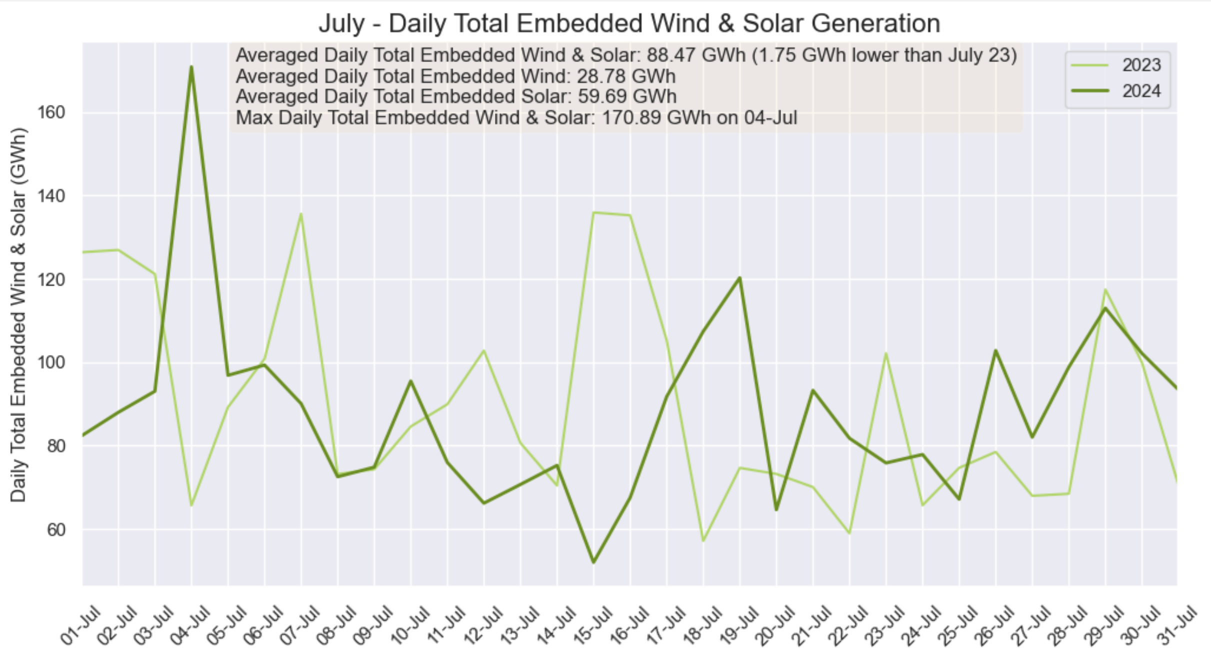
- Total Monthly National Demand (not shown below) was 23.7 TWh higher than July 2023.
- **Total Monthly Transmission System Demand*** was 13.9 TWh higher than July 2023.



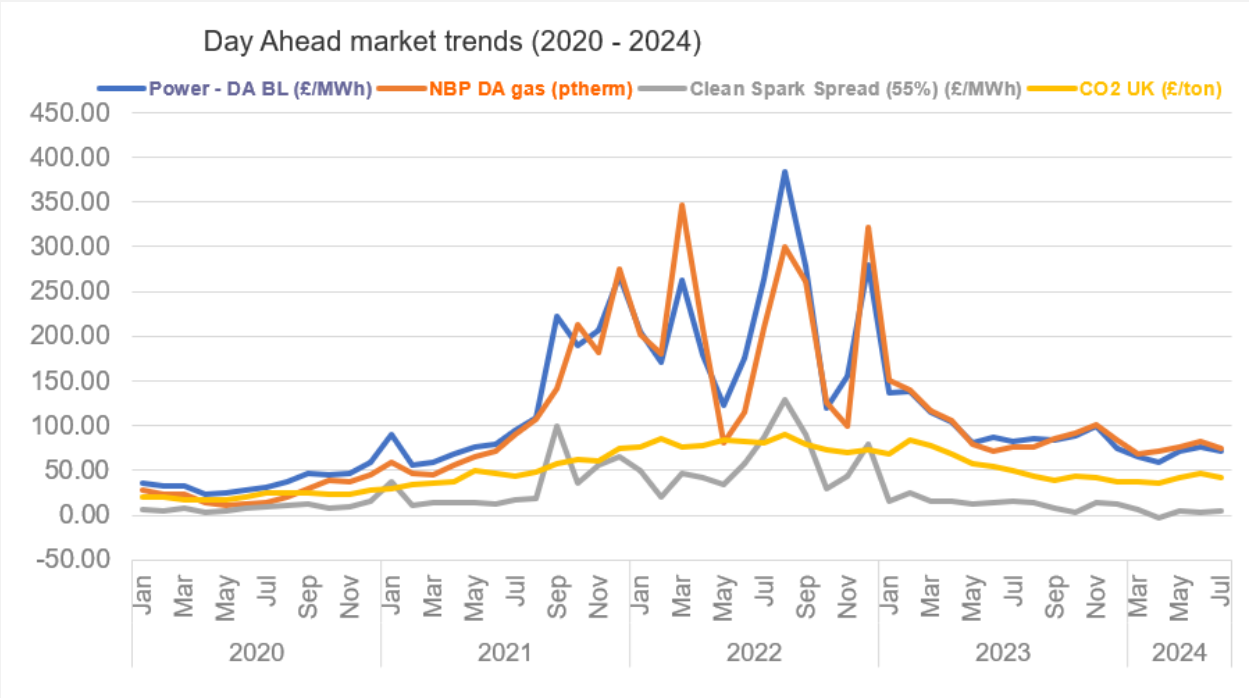
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

July daily Embedded Wind and Solar Generation

- **Monthly Total Embedded wind & solar generation** was 1.75TWh lower than in July 2023.
- The maximum daily total embedded wind & solar generation occurred on 4 July 2024 (170.9 TWh).



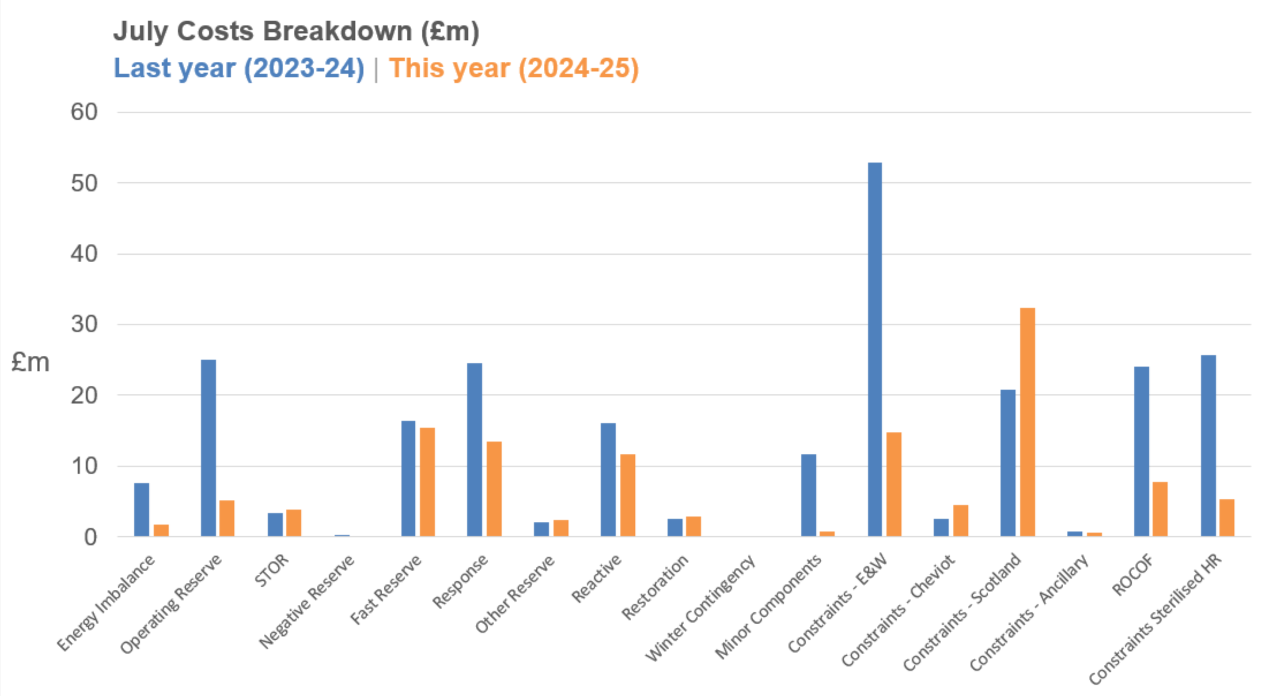
Price Trends in energy markets



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

Power, gas and CO2 reduced compared to last month, with a consequent slight rise in the Clean Spark Spread price. All trends remain lower compared to the previous year.

Balancing costs increases/decreases compared with the same period from last year



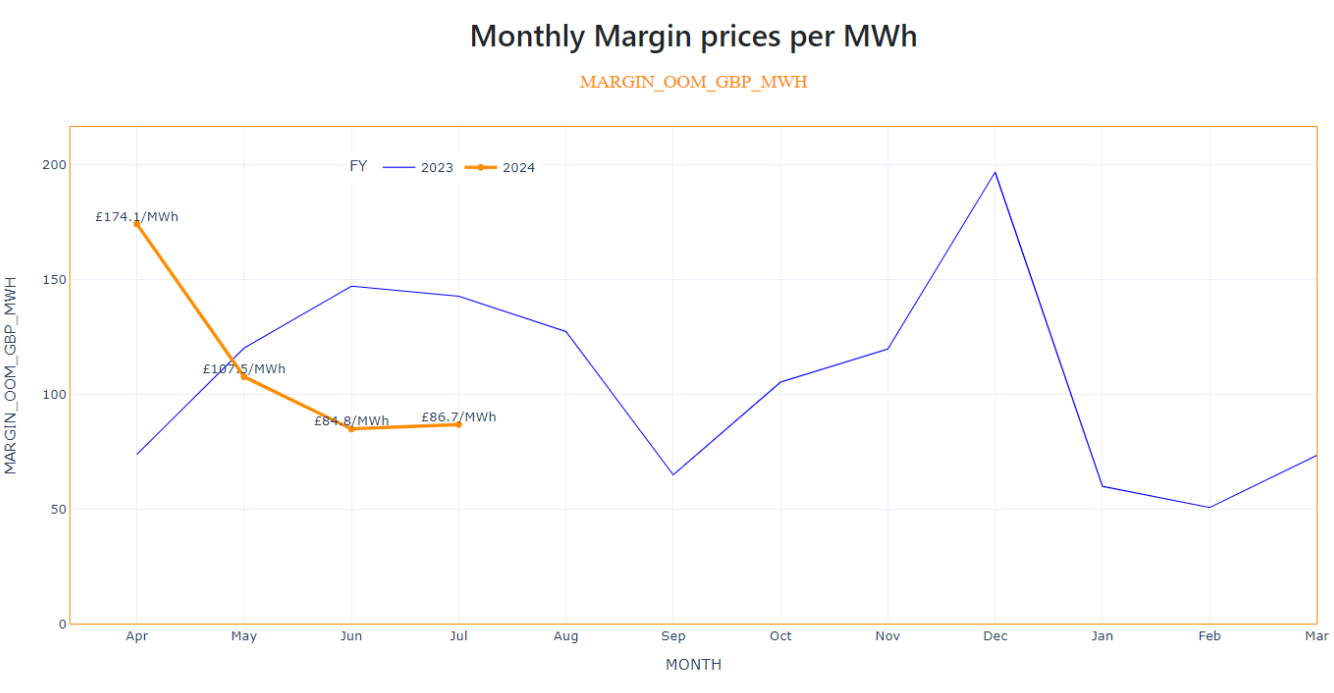
Comparing the non-constraint costs of July 2024 with those of July 2023, most categories showed a decrease or small deviation:

- **Reactive:** £4.5m decrease, due to the decrease in the weighted average price, from £4.4/MVAR to £3.8/MVAR.
- **Operating Reserve** £19.9m decrease following a 51 GWh decrease in reserve required to balance the system. The reduced cost experienced this year can be attributed, in part, to the lower energy prices compared to July 2023. Additionally, the introduction of the balancing reserve service in March has the potential to decrease reserve prices in the Balancing Mechanism (BM). We are currently in the process of quantifying the benefits associated with this service, and the results will be shared in the coming months.
- **Response**: £11.1m decrease due to 56 GWh less volume of actions taken.
- **Energy Imbalance:** £6.0m decrease despite a 72.8 GWh increase in the absolute volume of actions taken to balance the system.

Comparing the constraint costs of July 2024 with those of July 2023, there was a decrease in all categories except Scotland and Cheviot:

- **Constraints – Scotland & Cheviot**: £13.7m increase due to 138 GWh more absolute volume of actions.
- **Constraints – E&W**: £38.3m decrease due to taking 67 GWh less absolute volume of actions.
- **Constraints Sterilised Headroom***: £20.2m decrease due to an 82 GWh reduction in total volume of replacement energy.

Drivers for unexpected cost increases/decreases



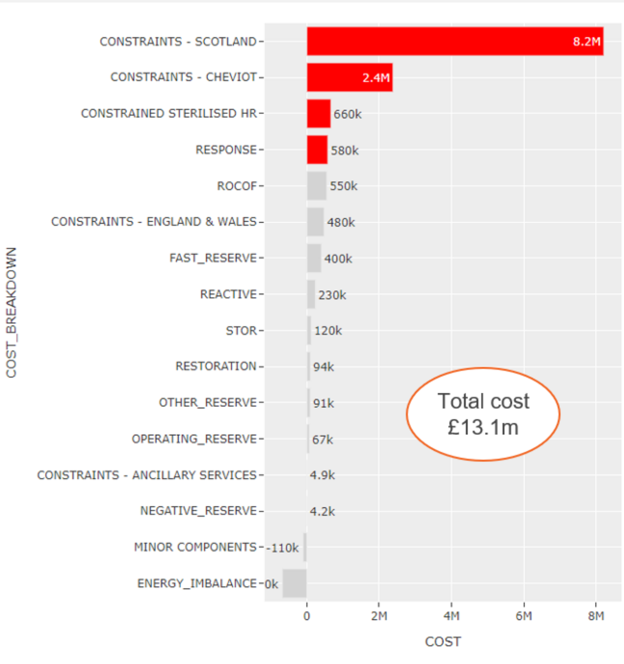
Margin prices decreased to £86.7/MWh in July 2024 compared to £142.6/MWh in July 2023 and increased slightly compared to June 2024.

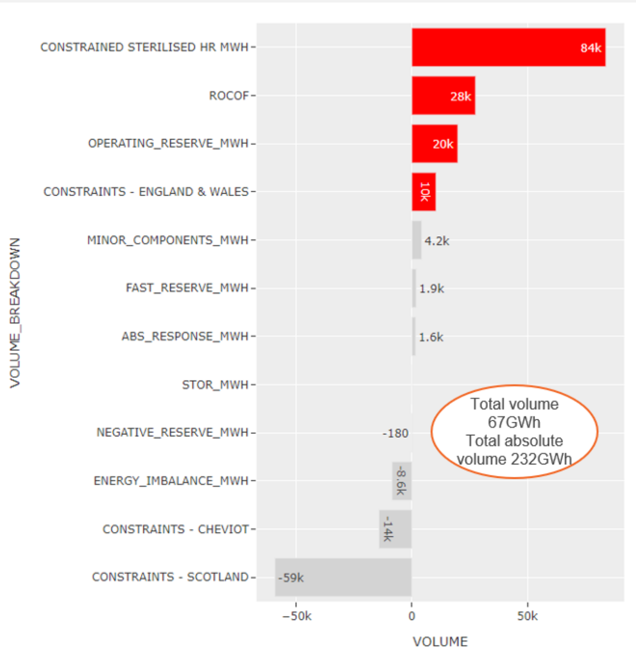
Daily Costs Trends

July's balancing costs were £123m which is £82.6m lower than the previous month. Only 1 day had a daily total cost over £10m, resulting in a decrease in the average monthly daily cost by £2.6m (from £6.9m to £4.3m).

The lowest total daily cost of £1.5m was observed on 31 July, whilst the highest total cost was observed on 4 July when the total spend was £13.1m (see 'Daily wind outturn' chart below). Thermal Export Constraints in Scotland dominated the cost breakdown on this day making up 63% of the daily cost. No individual action was expensive, but high volumes of wind curtailment contributed to the high total balancing costs for the day.

Cost breakdown for 4 July 2024

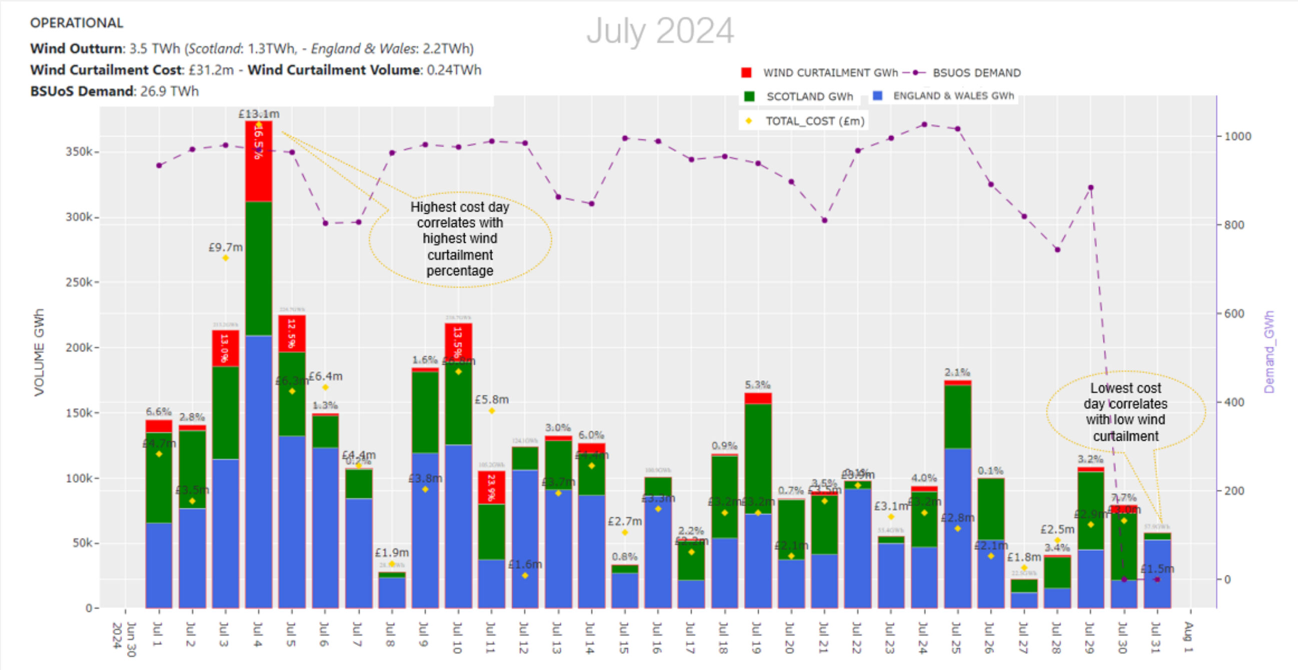




July Daily Wind Outturn – Wind Curtailment, Daily Costs and BSUoS Demand

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 – **purple** dotted line and daily cost – **orange** 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 the Demand Flexibility Service (DFS) is instructed by the ESO, this will be retrospectively accounted for in the data used to calculate performance.

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.

July 2024-25 performance

Indicative benchmark figures for 2024-25: 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: 2024-25 Monthly absolute MW error vs Indicative Benchmark

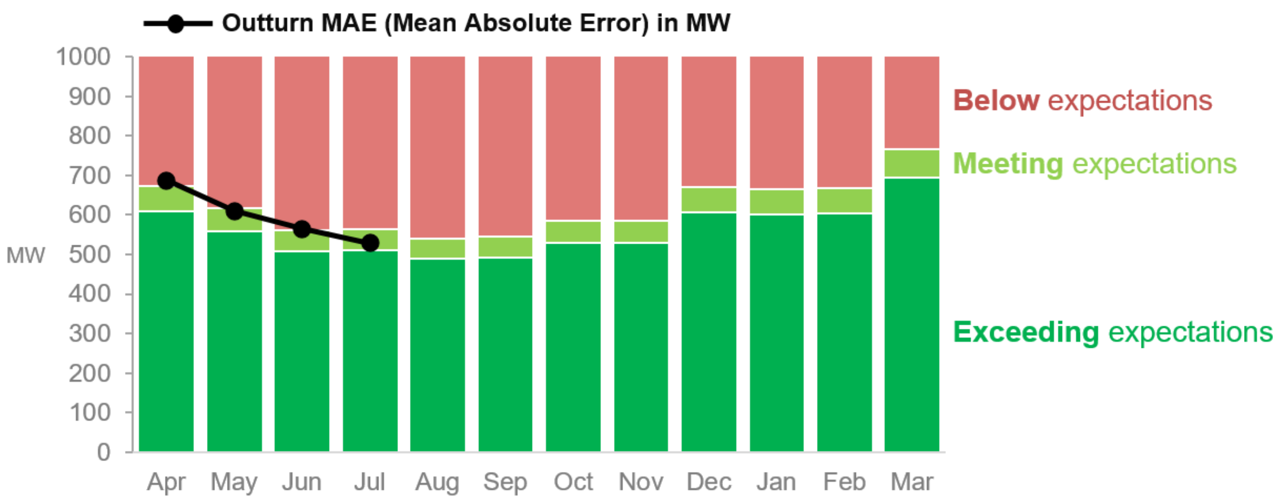


Table: 2024-25 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	642	588	534	538	515	519	558	557	639	632	636	730
Absolute error (MW)	**687**	**610**	**565**	**528**								
Status	●	●	●	●								

[2] Demand outturn | Insights Solution (elexon.co.uk)

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 July 2024, the mean absolute error (MAE) of our day ahead demand forecast was 528 MW compared to the indicative benchmark of 538 MW. The 5% range around this benchmark extends to 565 MW, meaning our performance met expectations for July.

The met office reports that weather in July was dominated by low pressure systems with only the occasional brief respite from a ridge of high pressure. Temperatures were consistently below average across the UK for the first two weeks, with unsettled weather and bands of rain brought on by several low pressure and frontal systems. A change in wind direction towards the end of the month allowed temperatures to climb well above average, but this was not sustained.

These frontal weather systems increased forecasting errors on a few days, mostly through the effects on embedded generation – solar errors contributing to 9th and 26th and wind errors on 22nd.

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	201	14%
1500 MW	61	4%
2000 MW	2	0%

The days with largest MAE were 9, 22 and 26 July.

Missed / late publications

There was one late publication on 27 July – this was due to an IT issue which is now resolved.

Triads

Triads run between November and February (inclusive) each year and therefore did not affect this month’s performance.

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.

July 2024-25 performance

Figure: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmark

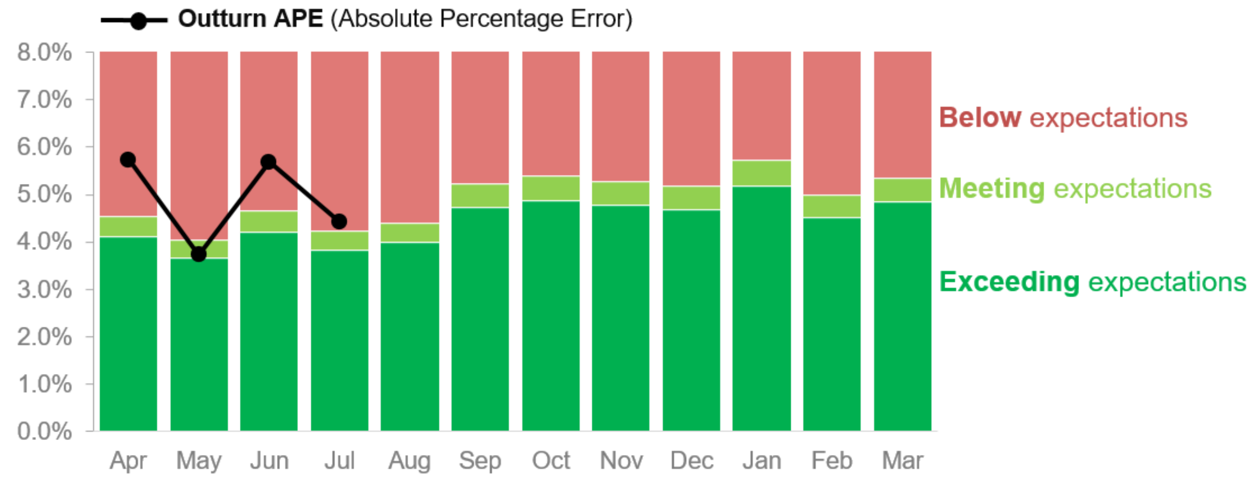


Table: 2024-25 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.32	3.85	4.43	4.02	4.19	4.98	5.13	5.02	4.93	5.46	4.74	5.09
APE (%)	**5.10**	**3.69**	**5.65**	**4.43**								
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.

Alternative view of BMU Wind Generation Forecast APE

We have agreed with Ofgem that for 2024-25, alongside the above monthly figures we will include a post-report updated APE% view which aims to exclude some of the factors that are outside of our control. This view excludes sites that have redeclared to zero, and incorporates Initial Settlement Runs (+16 Working Days). Both the benchmark and APE% reported below used this approach. A performance status is shown here, however this is for information only and is not part of the 2024-25 incentives assessment.

Please note that this new approach has also been proposed in the Consultation on Associated Documents to the proposed NESO licences – regulatory framework documents, which will come into effect when ESO transitions into NESO.

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.34	3.82	4.45	3.98	4.22	4.99	5.13	5.07	4.89	5.44	4.73	5.05
APE (%)	**4.60**	**3.68**	**5.40**	**4.36**								
Status	●	●	●	●								

Supporting information

In July 2024, the mean absolute percentage error (APE) was 4.43%, which is more than 5% higher than the benchmark of 4.02% and therefore below expectations.

The alternative APE (corrected for redeclarations to zero and revisions to Settlement Metering) is currently reported as 4.36% against the corresponding benchmark of 3.98% for July, which is also below expectations.

Monthly error was strongly affected by a handful of larger error days on 3, 6, 22 and 29 July. These days all appear to be over-forecasts (ie. forecast > outturn), so we are investigating whether there is a bias drift in the forecast models. We have applied tactical updates to some offshore windfarms, and performed an audit of the full fleet of models on the legacy system. We're currently waiting for the updates from this audit to be deployed onto the production system by our external IT partner.

Day ahead energy prices went negative for six consecutive hours on 4 July, causing approximately 1.2GW of redeclarations to 0. These appear as 'errors' in the 1C metric as the redeclarations happen after the day ahead forecast deadline. The alternative 1C metric accounts for these and shows an error on 4 July of 2.65% vs the standard 1C metric at 3.34%.

The tactical manual entry of outage data continues to be a source of forecast error, of which the process is largely dictated by limitations of our legacy system and the quality and consistency of the outage data.

The highest wind error (over-forecast) was 3.3GW on 6 July, occurring during Settlement Period 32. Allowing for processing time, the original weather forecast data for this 1C outturn period is approximately 1.5 days old.

Withdrawal of wind units

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

Missed / late publications

There was 1 late publication on 27 July – this was due to an IT issue, now resolved

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.

July 2024-25 performance

Figure: 2024-25 Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

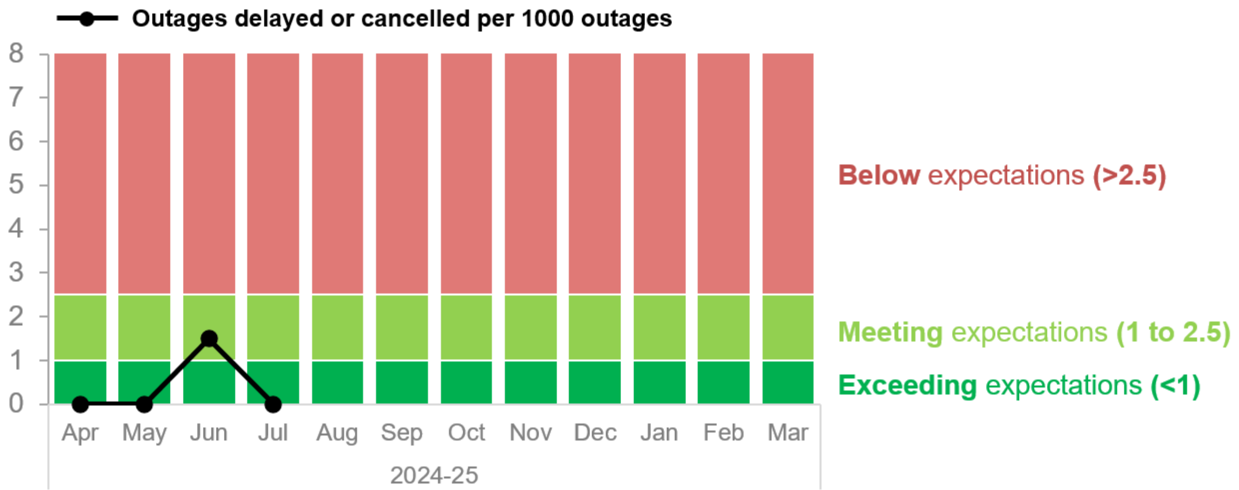


Table: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	673	614	670	784									2741
Outages delayed/cancelled due to ESO process failure	0	0	1	0									1
Number of outages delayed or cancelled per 1000 outages	0	0	1.49	0									0.36
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

For July, we successfully released 784 outages and there were zero delays or cancellations that occurred due to an ESO process failure. The number of stoppages or delays per 1000 outages is zero, which is inside the ‘Exceeds Expectations’ target of less than one delay or cancellation per 1000 outages. The number of outages released in July 2023 was 706 and has increased in July 2024 to 784, this is due to an increased number of outage requests received from the TOs/DNOs for this period. Overall, we are continuing to liaise with the TOs and DNOs to effectively facilitate maximum system access through weekly or month liaison meetings.

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.

July 2024-25 performance

Figure: 2024-25 Percentage of balancing actions taken in merit order to meet requirements in the Balancing Mechanism

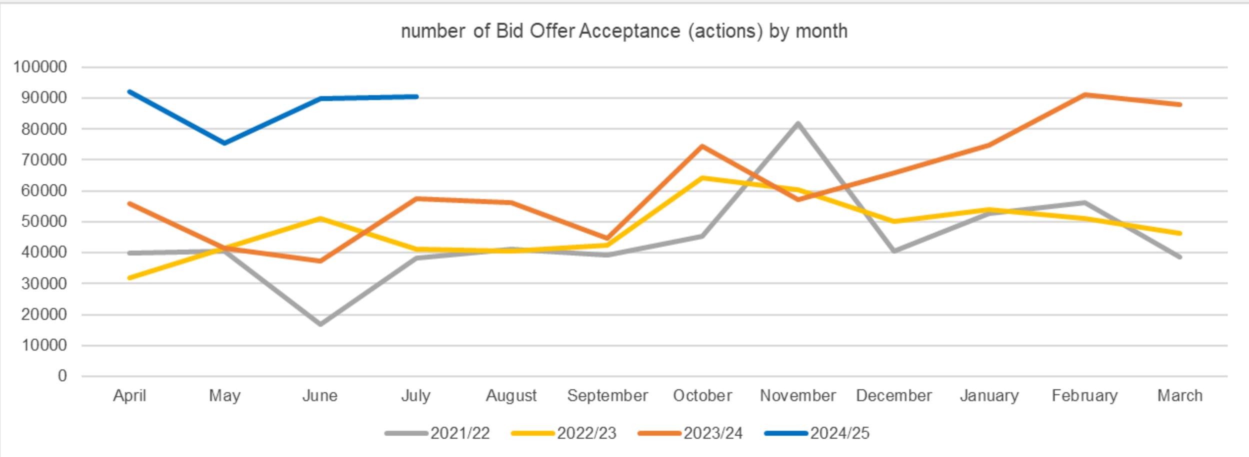
Table: Percentage of balancing actions taken outside of merit order in the BM

	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)	90.9%	90.9%	91.7%	96.3%								
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.4%	99.5%	99.4%	99.8%								
Percentage of actions with no category applied or reason group identified	0.6%	0.5%	0.6%	0.2%								

Supporting information

July performance

This month 96.3% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 3.5% 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 July, there were 90,394 BOA (Bid Offer Acceptances) and of these, only 213 remain with no category or reason group identified, which is 0.2% of the total.



Other activities

As mentioned previously, LCP Delta is progressing with their independent assurance report and we're committed to delivering this report to industry as soon as we are able. A new date for the webinar will be shared as soon as possible. Regular further updates will continue at the OTF.

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.

July 2024-25 performance

Figure: 2024-25 Average monthly gCO2/kWh of actions taken by the ESO (vs 2023-24)

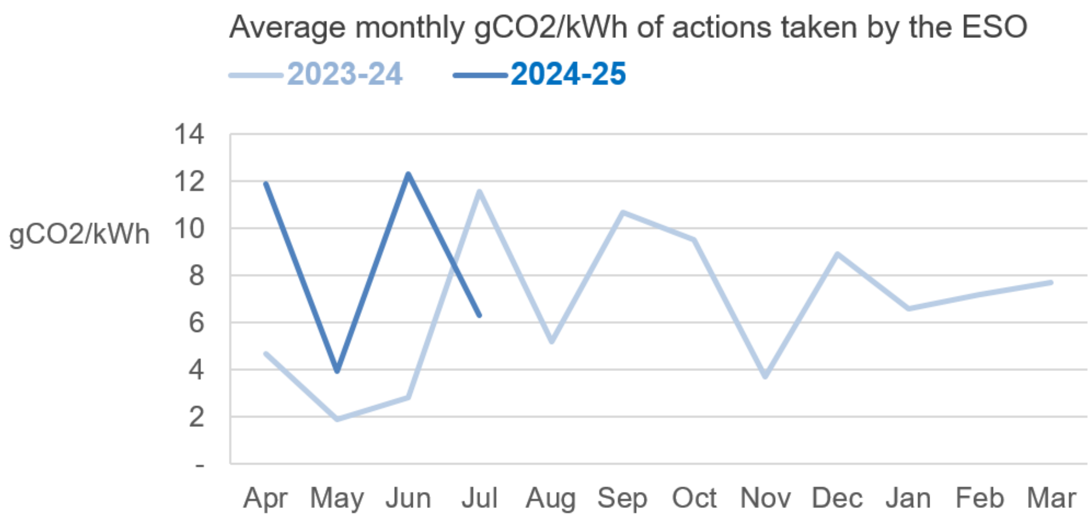


Table: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	11.87	3.93	12.31	6.33								

Supporting information

The average difference between Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied for July was 6.33gCO2/kWh. This is 5.98gCO2/kWh lower than the previous month.

In July 2024, the majority of carbon intensity increase from ESO actions took place across 3 and 4 July. Where the difference peaked at 66.36gCO2/kWh compared to a peak of 77.01gCO2/kWh in July 2023.

This was mainly due to transmission constraints relating to high wind output that required careful management on 3 July. On 4 July, the high wind output was focused in areas of high transmission congestion, and a 400kV substation trip on 4 July resulted in an increase from ESO actions.

Overnight on 14 and 21 July during early Sunday morning hours, the difference reached 37gCO2/kWh. The Euro's final took place on 14 July and at kick off the wind output reduced by 300MW leading to an increase of

ESO actions. On 21 July a system failure relating to the BM resulted in increased actions until the issue had been rectified.

The remainder of the month’s ESO interaction was lower than the YTD average of 8.61gCO_2/kWh.

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.

July 2024-25 performance

Table: Frequency and voltage excursions (2024-25)

	2024-25											
	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								
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0								
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0								

Supporting information

July performance

There were no reportable voltage or frequency excursion in July 2024.

[3] 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.

July 2024-25 performance

Table: 2024-25 Unplanned CNI System Outages (Number and length of each outage)

Unplanned	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0								
Integrated Energy Management System (IEMS)	0	0	0	0								

Table: 2024-25 Planned CNI System Outages (Number and length of each outage)

Planned	2024-25											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	1 outage 265 mins								
Integrated Energy Management System (IEMS)	0	0	0	0								

Supporting information

July performance

In July 2024 there was one planned CNI system outage. The outage was to carry out regular maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

This change took place on 11 July, and was planned in advance, in collaboration with our control rooms to ensure it did not introduce a conflict with other known periods of high activity. Notifications are posted to the industry, via BMRA, at 7 days prior and 1 day prior.

On the day of an outage, our control rooms are again consulted to confirm that conditions remain suitable to proceed with the change or, if required, whether the change must be rescheduled.

Additionally, on the day, notifications are posted to the industry, via BMRA, when the outage is due to start, and when it is complete.

There were no other planned outages during July.

Role 2 (Market developments and transactions)

ESO

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. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) are forecast for six-monthly tariffs and set 9 months ahead of the chargeable tariff period. For 2024/25, Fixed Tariff 3 (April 24 – Sep 24) was published in June 2023. Fixed Tariff 4 (Oct 2024 – Mar 2025) was published in December 2023.

We continue to forecast balancing costs monthly and measure our performance against this forecast. 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).

July 2024-25 performance

Figure: 2024-25 Monthly BSUoS forecasting performance (Absolute Percentage Error)

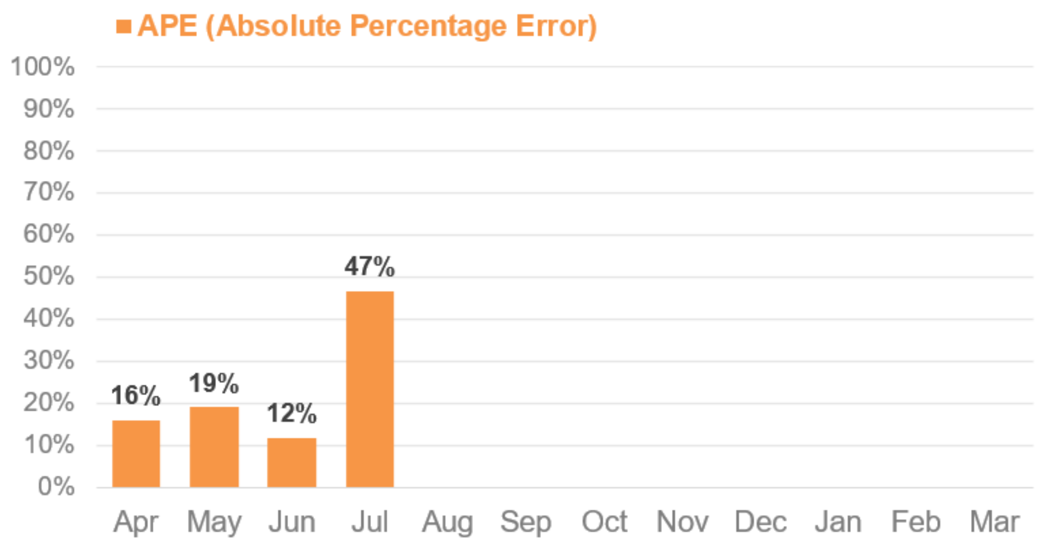


Table: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	11.5	8.5	12.7	8.0								
Month-ahead forecast (£ / MWh)	9.7	10.2	11.2	11.7								
APE (Absolute Percentage Error)[5]	**16.0**	**19.0**	**11.8**	**46.6**								

[5] 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

July Performance:

Actuals out-turned below forecast for July, with an Absolute Percentage Error of 46.6. The increase in absolute percentage error from last month was a result of below forecast costs.

Costs:

July outturn costs were around the 15th percentile of the forecast produced at the beginning of June. There was a 16% decrease in the average wholesale electricity price between the June forecast for July (£76/MWh) and July outturn (£64/MWh). Constraint costs were below 42% below forecast (£112m forecast and £65m outturn). The proportion of demand met by renewables was also 10% lower than our June forecast (29% forecast and 19% outturn). The proportion of demand met by renewables is one of the main drivers in BSUoS cost, with higher proportion tending to drive higher constraint costs.

We are continuing to review the performance of the BSUoS forecast model, to identify any updates required to the modelling approach. The forecast covers a wide range of lead times, and therefore uses a blended approach, to combine the output of different models and capture variability over different time scales. Following the higher APE this month, we will review if there is a trend to the over-forecasting of constraints costs, with any subsequent changes to our modelling approach being communicated to industry.

Volumes:

July actual volume was above the June forecast. This small variance could be due to weather and temperature fluctuations.

Forecast for July made at the start of June: 20.1TWh

July outturn: 20.3TWh

Notable events during July 2024

Power Responsive annual report 2023 published

We published the latest Power Responsive Annual Report on 10 July, which reflects on policy, regulatory and market developments in 2023 as well as trends in demand side flexibility participation. This report is designed to help stakeholders navigate industry change and complexity and support the continued development of demand side participation in flexibility markets.

The report covers:

- Highlights of recent policy, regulatory and industry-led initiatives supporting or impacting Demand Side Flexibility (DSF).
- Demand side metrics showing activities across ESO and Distribution System Operator markets in 2023.
- Future outlook for demand side markets and flexibility opportunities.

Everoze compiled the report on behalf of Power Responsive, with contributions from DESNZ, Ofgem and Kraken.

Review of Electricity Market Arrangements (REMA) update: scheduling and dispatch options webinar

The REMA Dispatch & Balancing team held a webinar around scheduling and dispatch options being considered in DESNZ' REMA Programme. They outlined the context for proposed changes, the issues underpinning current and future dispatch arrangements, and potential arguments for or against each potential future dispatch model.

The team outlined counterfactual (planned or in-flight reforms that will have an impact on dispatch efficiency) and counterfactual+ (potential reforms which could be delivered by ESO or industry independent of wider REMA policy reform or significant influence from DESNZ or Ofgem) scenarios, aimed at enabling effective assessment of potential REMA reforms.

At the heart of the webinar were 7 potential dispatch models, with high-level descriptions, component building blocks, market timelines, and hypothesised advantages and disadvantages. At the end of each model introduction, breakout groups were formed to encourage discussion about the pros and cons of each model; giving industry participants a forum to express any concerns about any aspects that might be incomplete or missing, unclear or worrying, or indeed a positive. Further information can be found here.

While stakeholders disagreed on the advantages/disadvantages of different models, they agreed we had identified the right spectrum of models for further evaluation and appreciated the detail with which they were set out.

Role 3
(System insight, planning and network development)

ESO

Metrics and RREs: Please note there are no metrics or monthly RREs for Role 3

Notable events during July 2024

Publication of our Future Energy Scenarios (FES) 2024 plus launch event

On 15 July, we launched our annual Future Energy Scenarios (FES) publication, a report that presents credible ways to decarbonise our energy system as we strive towards UK Government's 2050 net zero initiative.

A physical event marked the publication launch, live streamed from The Institution of Engineering and Technology in London, followed by a four-part series of deep dive webinars several days later.

FES has evolved this year to adapt to the expanding responsibilities of the National Energy System Operator (NESO) to support the development of strategic network planning through the Centralised Strategic Network Plan (CSNP) and Strategic Spatial Energy Plan (SSEP). This strategic shift is also reflected in the publication's new title – 'Future Energy Scenarios: ESO Pathways to Net Zero 2024' – the first publication title change since FES' inception in 2011.

As part of this wider industry development, this year's FES features a new framework that presents three net zero 'pathways' that meet current emissions targets, together with a 'Counterfactual' that misses net zero. These pathways explore three strategic and credible routes to net zero with different dominating energy vectors and levels of demand side flexibility.

You can read Future Energy Scenarios: ESO Pathways to Net Zero 2024, along with the full suite of FES 2024 documents and launch webinar recordings on the FES pages of our website.