ESO RIIO2 Business Plan 2 (2023-25)

August 2023 Incentives Report

25 September 2023

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.

Please see our website for more information.

Summary of Notable Events

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

- As the first part of our Stability Market Design innovation project, we intend to undertake the first tender round for the mid-term (Y-1) market later this year. We're currently reviewing the feedback from the Request For Information (RFI) that closed on 18 August and will soon be able to share more about next steps and timeline.
- Following the conclusion of the industry consultation on Enduring Auction Capability (EAC) Article 18, we have now submitted our proposals to Ofgem for approval and expect a result by mid-October 2023.
- On 31 August, we submitted our Demand Flexibility Service (DFS) Winter 23/24 EBR Article 18 consultation responses to Ofgem for approval. The consultation was on the terms and conditions of a revised DFS for this coming winter. The consultation created a significant response with 32 providers submitting detailed responses to the consultation.
- On 29 August, we published the 2023 Electricity Ten Year Statement (ETYS), which shows our view of GB's National Electricity Transmission System (NETS) over the next 10-20 years. This is an annual document which helps us to understand the future requirements of the system and where investment and development is needed to help us achieve our zero-carbon ambition.

Summary of Metrics and RREs

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

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£171m vs benchmark of £194m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 465MW vs indicative benchmark of 497MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.90% vs indicative benchmark of 3.89%	●
Metric 1D	**Short Notice Changes to Planned Outages**	2.8 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**	95.6% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	5.2gCO_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**	0 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 7.2%	N/A

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

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

Adelle Wainwright

Acting ESO Regulation Senior Manager

Role 1 (Control Centre operations)

ESO

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:

1. The benchmark has been created using monthly data from the preceding 3 years.

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

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

4. 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.

August 2023-24 performance

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

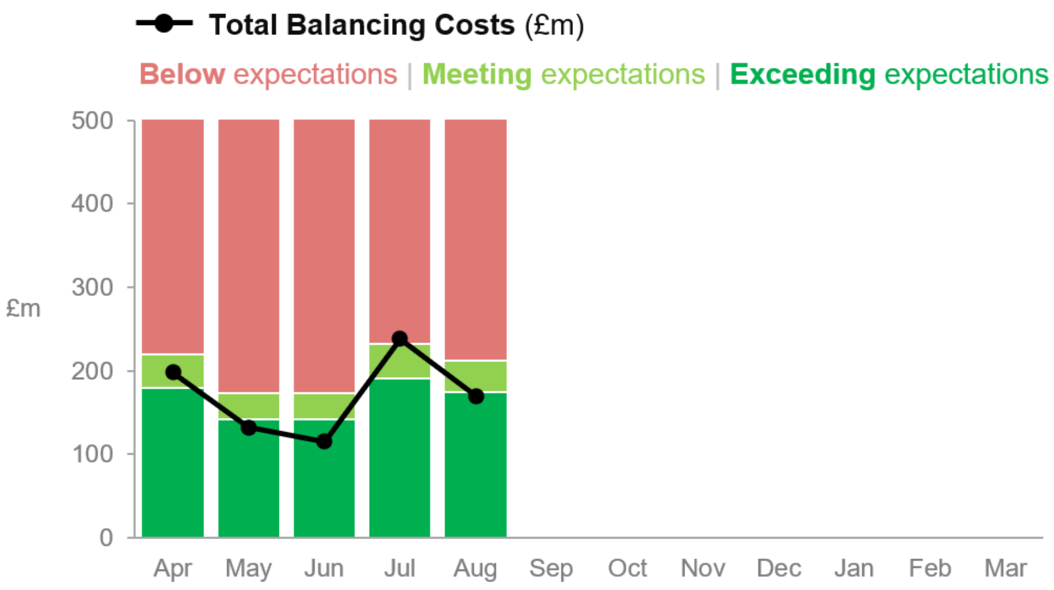


Table 1: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

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								16.8
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86								n/a
Benchmark	200	157	158	212	194								920
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**								**855**
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

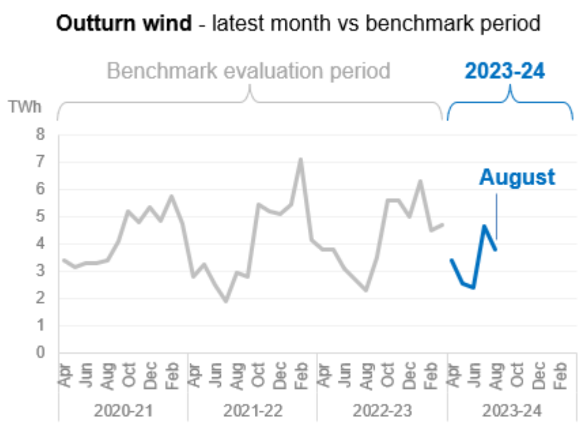
ℹ	**Ongoing data issue:**	Please note that due to a data issue over the previous months, the Minor Components line in Non-Constraint Costs is capturing some costs which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to 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.

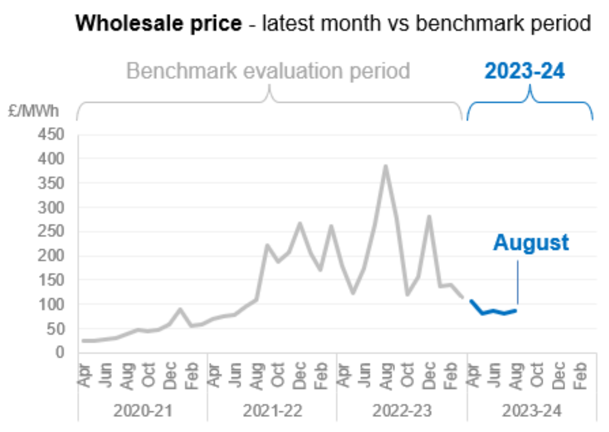
This month's benchmark

The benchmark of £194m reflects:

- a slightly-below-average **outturn wind** figure compared to the benchmark evaluation period (the last three years).
- a relatively low average monthly **wholesale price** (Day Ahead Baseload) compared to the benchmark evaluation period (the last three years).

[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.





August performance

This month the average wholesale price remained low, and the wind out-turn decreased from the previous month. This resulted in a lower benchmark of £194m. We were able to exceed expectations against this benchmark by delivering costs £23m lower than the benchmark with an outturn of £171m (compared to £238m in July). This performance is possible due to the ESO's commitment to minimising costs to consumers through all ENCC decisions in operational timescales which is enabled by the wide range of activities outlined in our balancing costs strategy and portfolio of activities.

Breakdown of costs vs previous month

Balancing Costs variance (£m): August 2023 vs July 2023

		(a) Jul-23	(b) Aug-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	7.6	-0.2	(7.9)	
	Operating Reserve	25.0	12.3	(12.7)	
	STOR	3.4	3.5	0.1	
	Negative Reserve	0.3	0.3	0.0	
	Fast Reserve	16.9	14.5	(2.4)	
	Response	24.7	17.8	(6.9)	
	Other Reserve	2.1	1.1	(0.9)	
	Reactive	16.0	15.0	(1.0)	
	Restoration	3.8	2.6	(1.2)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	12.9	6.4	(6.5)	
Constraint Costs	Constraints - E&W	52.9	48.6	(4.3)	
	Constraints - Cheviot	2.5	4.6	2.1	
	Constraints - Scotland	20.8	23.3	2.6	
	Constraints - Ancillary	0.2	0.2	(0.1)	
	ROCOF	24.1	8.2	(15.9)	
	Constraints Sterilised HR	25.6	12.9	(12.7)	
Totals	Non-Constraint Costs - TOTAL	112.6	73.3	(39.4)	
	Constraint Costs - TOTAL	126.0	97.8	(28.2)	
	Total Balancing Costs	**238.7**	**171.1**	**(67.6)**	

As shown in the total rows from the table above, the non-constraint & constraint costs both decreased by £39.4m & £28.2m respectively, resulting in an overall decrease of £67.6m compared to July 2023.

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

- **Constraint-England & Wales***: £4.3m decrease, despite the higher volume of actions by 162GWh
- **Constraint-Scotland***: £2.6m increase, due to slightly higher volume of actions.
- **Constraints Sterilised Headroom**: £12.7m decrease. Cost decrease is in line with the decreasing of constraint actions because less headroom had to be replaced using Balancing Mechanism (BM) actions on the system outside the constraint.

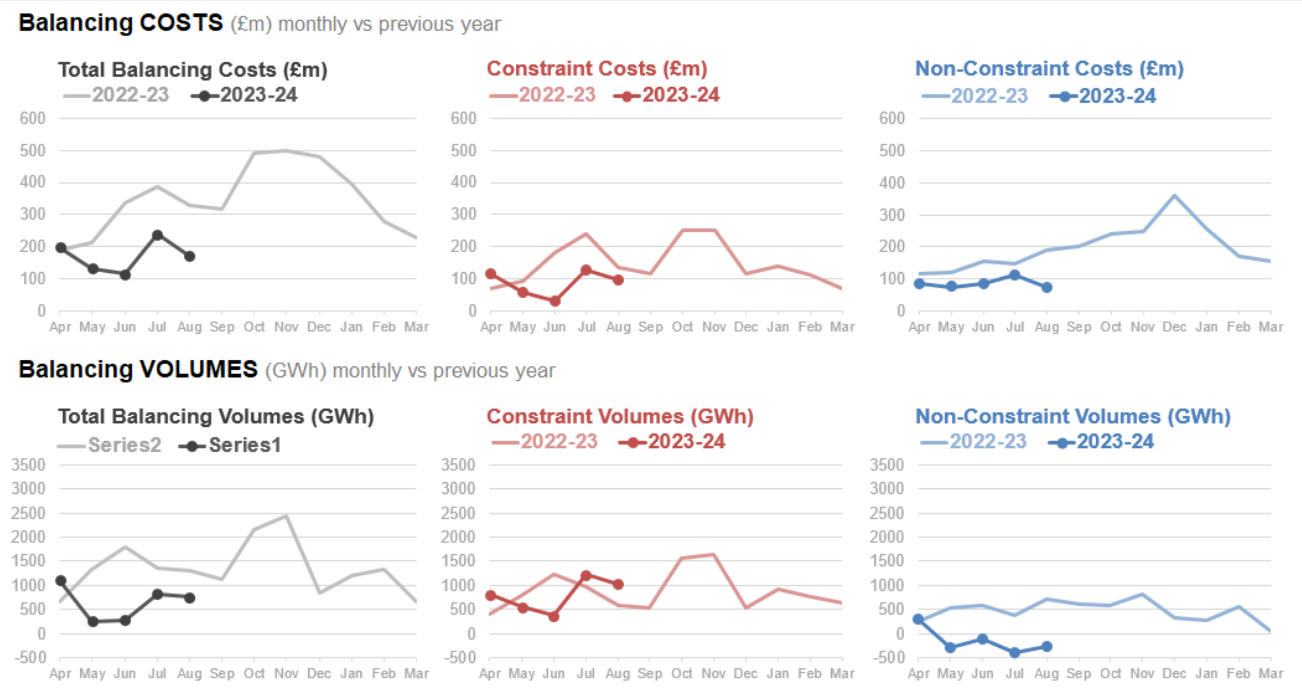
- **ROCOF**: £15.9m decrease, 210GWh less volume compared to the previous month

*The volume weighted average for export constraints decreased in August by £14 /MWh

Non-constraint costs: The main drivers of the biggest variances this month are detailed below:

- **Energy Imbalance**: £7.9m decrease. The market was mainly long except the evening peak demand period throughout the month.
- **Operating Reserve**: £12.7m decrease and half the volume of actions compared to the previous month
- **Response**: £6.9m decrease, due to a £75 /MWh drop in the volume weighted average
- **Minor Components**: £6.5m decrease due to the lower volume of actions

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 narrative below discusses the broad themes of spend. 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 £39.2m lower than in August 2022 due to: • Lower average wholesale prices**
Compared with last month:	Constraint costs were £28.2m lower than in July 2023 due to: • lower volume of actions (over 190GWh less than last month)

Non-constraint costs

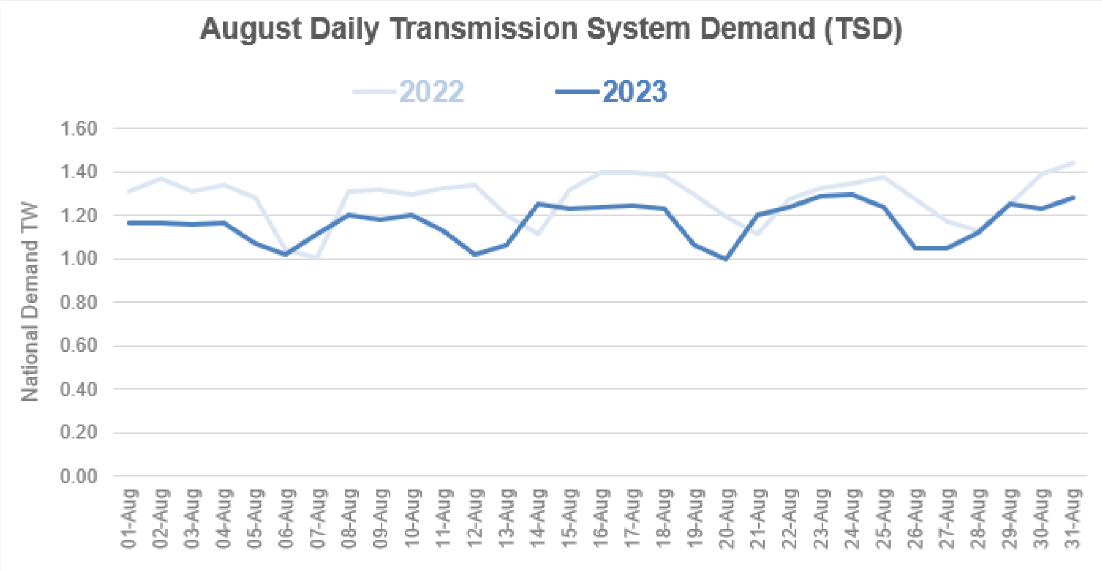
Compared with the same month of the previous year:	Non-Constraint costs were £117m lower than in August 2022 due to: • Significant decrease of the volume of actions (976 GWh less than the previous year) • Lower average wholesale prices **
Compared with last month:	Non-Constraint costs were £39.4m lower than in July 2023 due to: a significant drop in volumes for Operating Reserve.

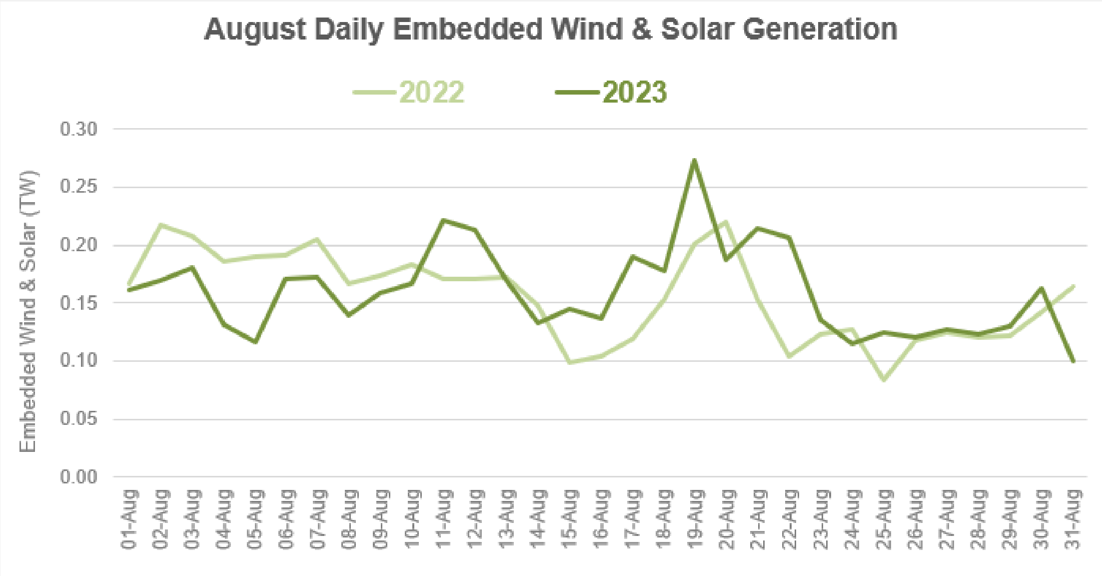
** Average wholesale prices August-23 £86 /MWh instead of £383/MWh of August-22

August daily National Demand (TSD*), Embedded Wind and Solar Generation

National Demand was 3.5TW lower than the same period last year (3.5TW lower)

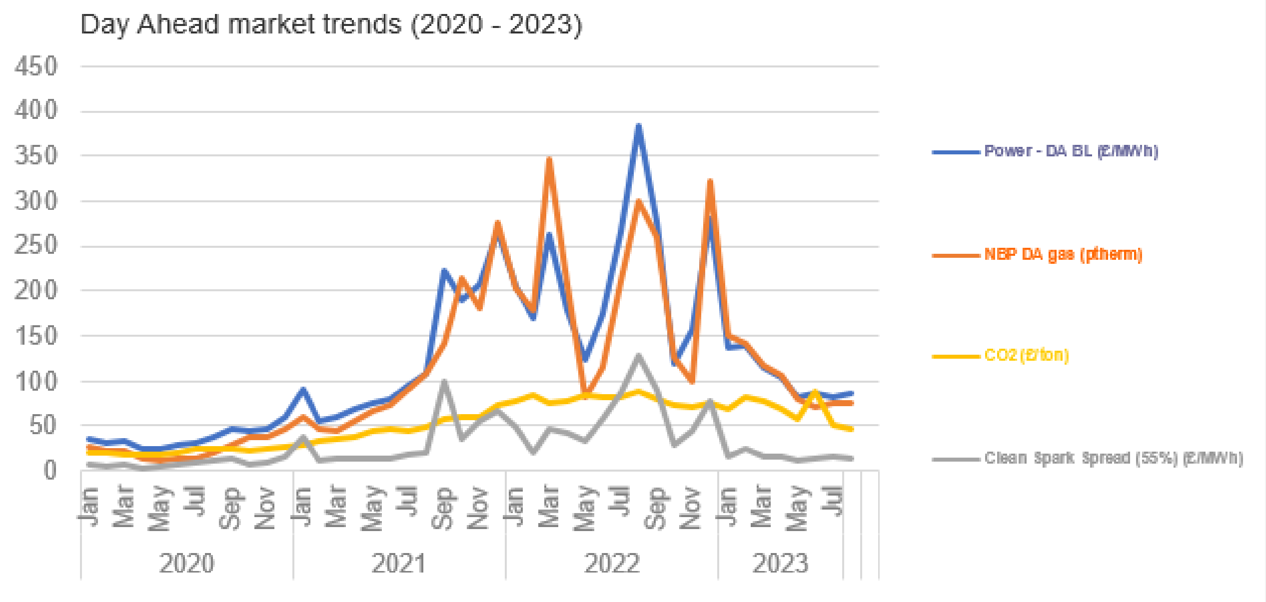
Embedded wind & solar generation was 144GW higher than the same period last year





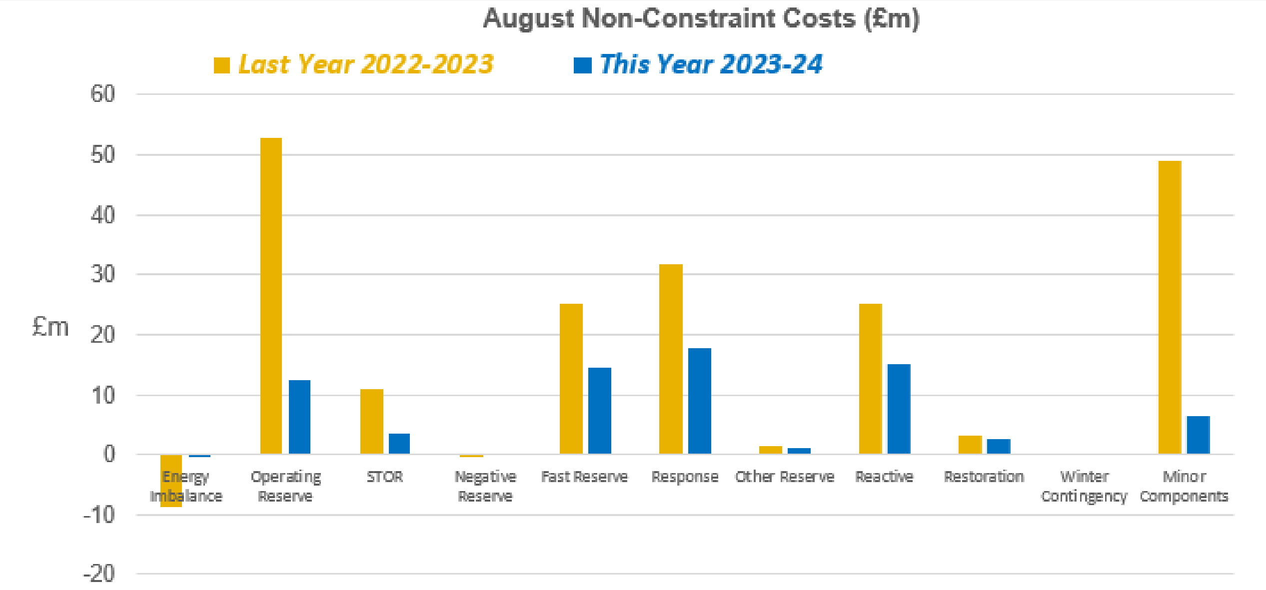
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand 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 trends decreased or had a small deviation from last month and remain lower compared to the previous year.



Comparing the non-constraint costs of August 2023 with those of August 2022, all the categories showed a decrease

- **Operating Reserve** £40.5m decrease due to ~260GWh less volume of actions taken to balance the system and the lower average wholesale prices
- **Response decreased** by £14m, due to lower average wholesale prices and a 150GWh decrease in the absolute volume of actions.
- **Minor Components decreased** by £42.4m. 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

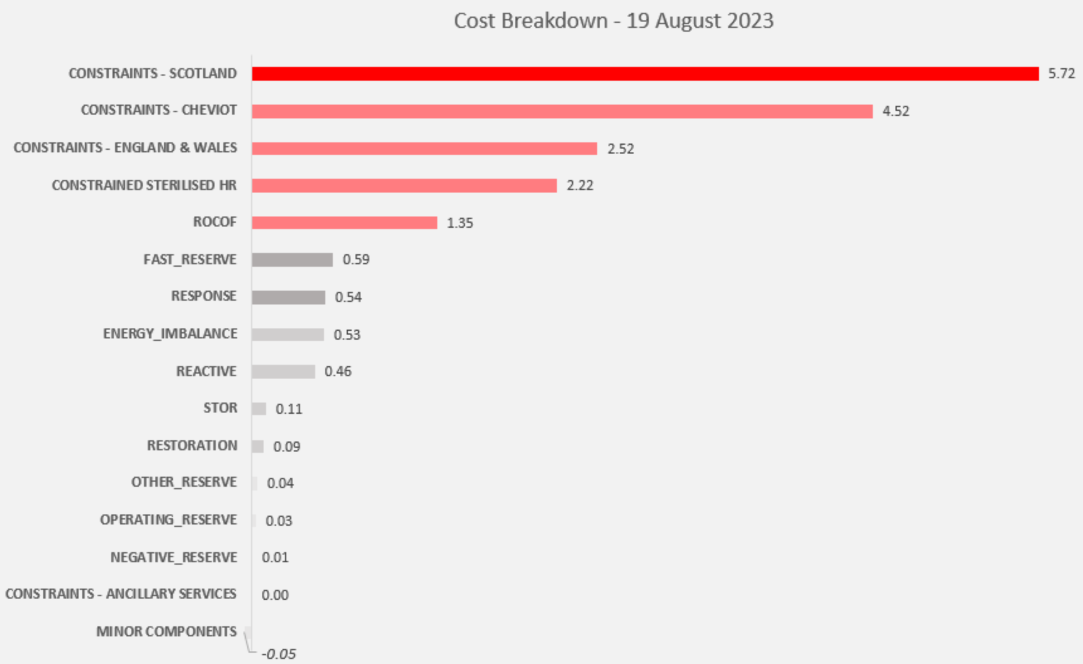
Margin prices (the amount paid for one MWh) have decreased compared to July 2023 and the corresponding period of the previous year.

Daily Costs Trends

As mentioned above, August's balancing costs were £68m lower than the previous month.

At the date of publication, we have recorded 6 days with a spend of more than £10m.

On the Saturday 19 August when the total spend was £18.7m, the major cost components were driven by high renewable generation and low demand. No individual action was extremely expensive, but high volumes of wind curtailment, combined with a large volume of RoCoF actions resulted in high total balancing costs.



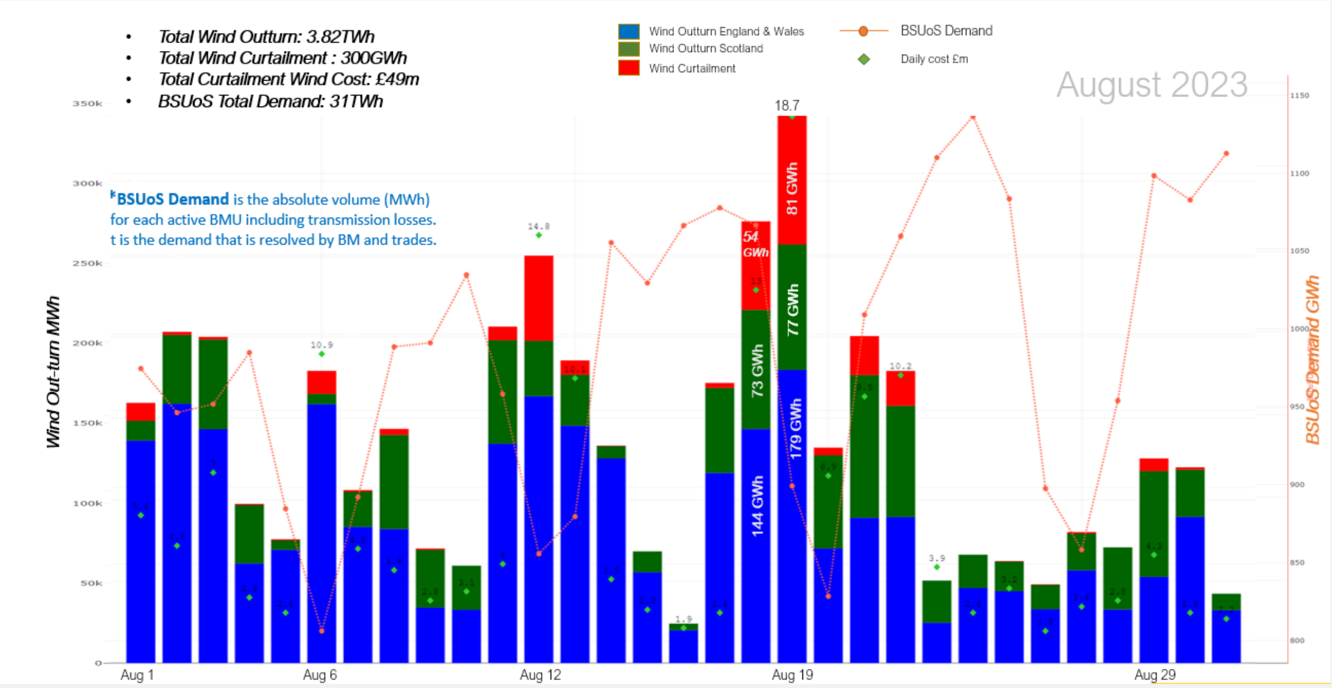
The minimum cost of £1.8m was observed on 26 August.

The average daily spend for the month was £5.6m, a £2.2m decrease from the previous month.

Daily Wind Outturn – Wind Curtailment and BSUoS Demand

The chart below serves the purpose of supporting the transparency and the narrative 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.

August 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

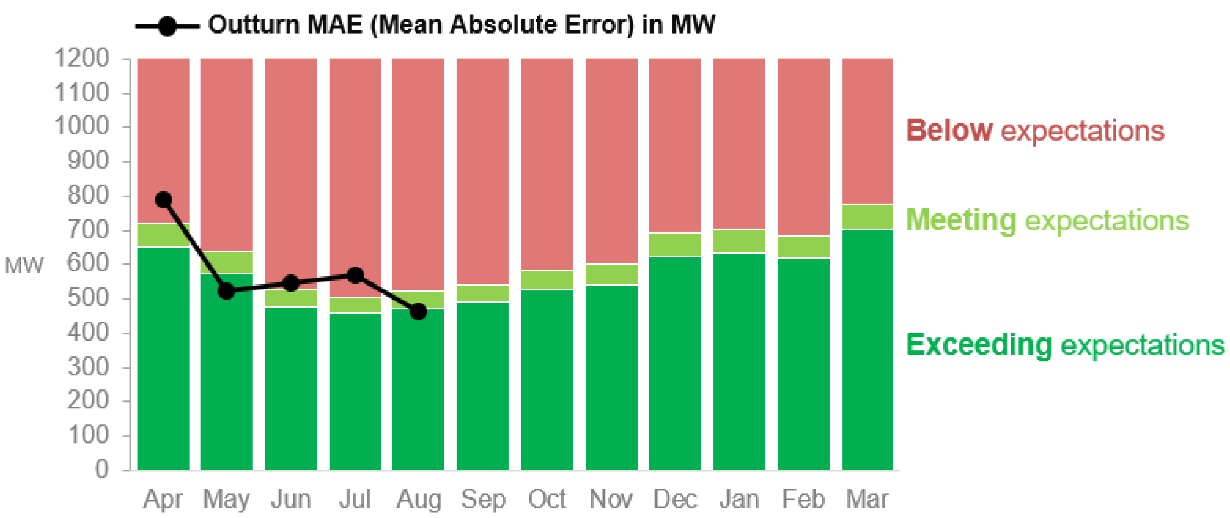


Table 2: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	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**							
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 August 2023, the mean absolute error (MAE) of our day ahead demand forecast was 465 MW compared to the indicative ‘meeting expectations’ target of 522 MW, and indicative ‘exceeding expectations’ target of 472 MW.

The weather in August was slightly warmer than average with occasional cold spells. Two named storms brought unseasonably wet and windy weather to many parts of the UK on the 5th and 18th/19th. Sunshine was slightly below average, especially in the southwest.

Demand forecasting performance exceeded expectations on most days during August.
The largest errors were on 18/19 August, were storm Betty brought particularly unstable and variable wind conditions. Solar errors due to variable cloud cover on 22 and 28 August were the significant factor on those days.

On several occasions during the month large demand swings have been noticed, coinciding with European interconnector variance. These appear to be due to embedded generators being flexed to accommodate interconnector energy changes, leading to increased demand forecasting errors. Investigations are ongoing to identify the precise generation source and market factors triggering these actions.

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	154	10%
1500 MW	40	3%
2000 MW	12	1%

The days with largest MAE were Aug 19, 20 and 22.

Missed / late publications

There were zero occasions of missed or late publications in August.

Triads

Triads only take place between November and February and therefore did not impact on forecasting performance during Q2.

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.

August 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

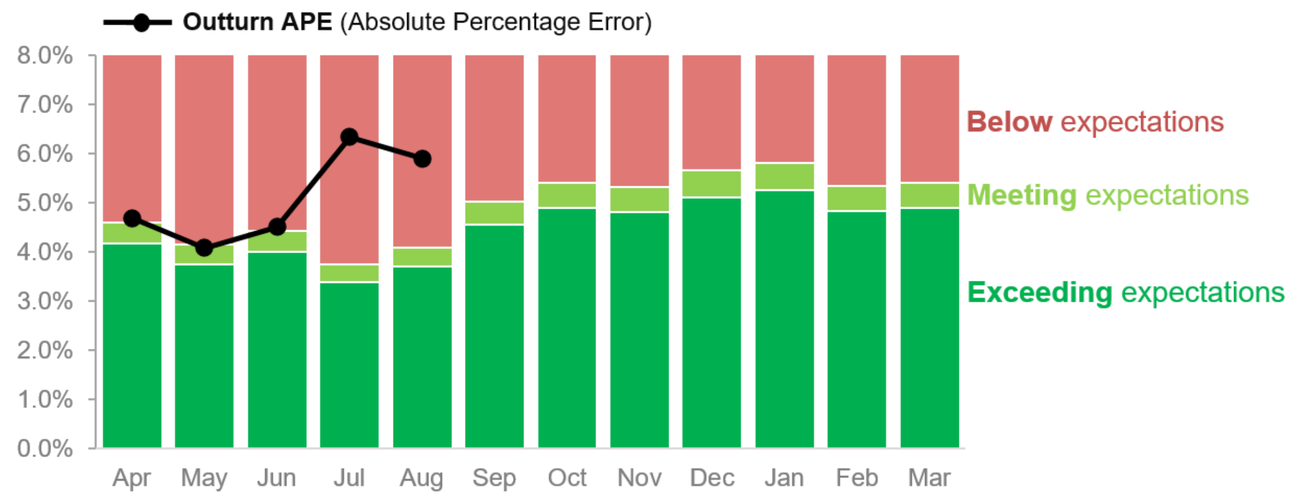


Table 3: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	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**							
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

August performance

August’s the wind power forecast accuracy was 5.9% against the benchmark of 3.89% and therefore below expectations.

August began with a deep area of low pressure over the Irish Sea, bringing unsettled weather to the surrounding area. This became the theme for August with a strong Jet Stream pushing low pressure systems across the UK. Storm Antonio passed through in early August and Storm Betty in mid-August.

Substantial wind forecast errors were observed though most of the month, with the peak error occurring on 1 August being in excess of 4.5GW. An internal investigation is ongoing for this occurrence, we expect this to be completed in September 2023.

As a result of the sustained errors throughout August, we carried out a forensic audit of the wind farm portfolios. This revealed a significant misalignment of the BMU portfolio between the different systems we use for reporting. We are working to assess the impact and correct this misalignment of data between our systems. We are doing this by collaborating across other teams within the ESO and have set up a task force working group.

In August there were no known occasions of negative prices and no evidence of wind farms reducing output for commercial reasons.

Withdrawal of wind units

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

Missed / late publications

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.

August 2023-24 performance

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

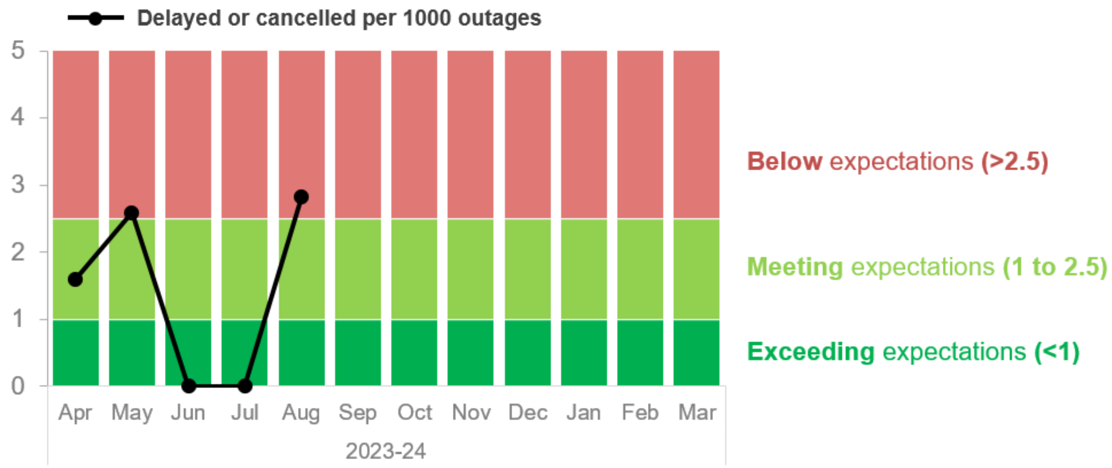


Table 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706								3358
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2								5
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8								1.48
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 August, the ESO has successfully released 706 outages. There were two occurrences of delays or cancellations due to ESO process failure. The number of stoppages or delays per 1000 outages for August was 2.83, which is outside of the 'Meets Expectations' target of less than 2.5. The two events can be summarised below:

The first delay occurred on an outage for a substation Mesh Corner and 275kV circuit that coincided with an existing outage. Further to this, there was a known technical limitation at this site due to a hot joint and this resulted in the equipment being down-rated by the Transmission Owner. The technical limitation was not picked up by the Planning department and the constraint limit provided to the ESO control room was significantly higher than what they could achieve. Consequently, if the outage was released then the network would be very challenging to manage due to a very low constraint limit to operate within. Therefore, the decision was made that prior outage could not overlap with the new outage until the technical limitation was resolved. An Operational Learning Note (OLN) is being written to capture preventative actions.

The second delay occurred on an outage that included an Super Grid Transformer (SGT) and a Shunt Reactor. There was a discrepancy between the tool used within planning timescales (Offline Transmission Analysis) and the real-time software used by the control room (Power Network Analyser) to assess the impact on managing the network voltage. The planning software did not flag any voltage breaches post-fault whereas the real-time software observed unacceptable high post-fault voltages for a specific fault. Consequently, this could not be released by the ESO control room and it was sent back to the Planning department to investigate. This feeds into an on-going investigation into the cause of the discrepancy between the two tools.

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 that are seemingly out of 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.

August 2023-24 performance

Figure 5: 2023-24 Percentage of balancing actions taken in merit order in the BM

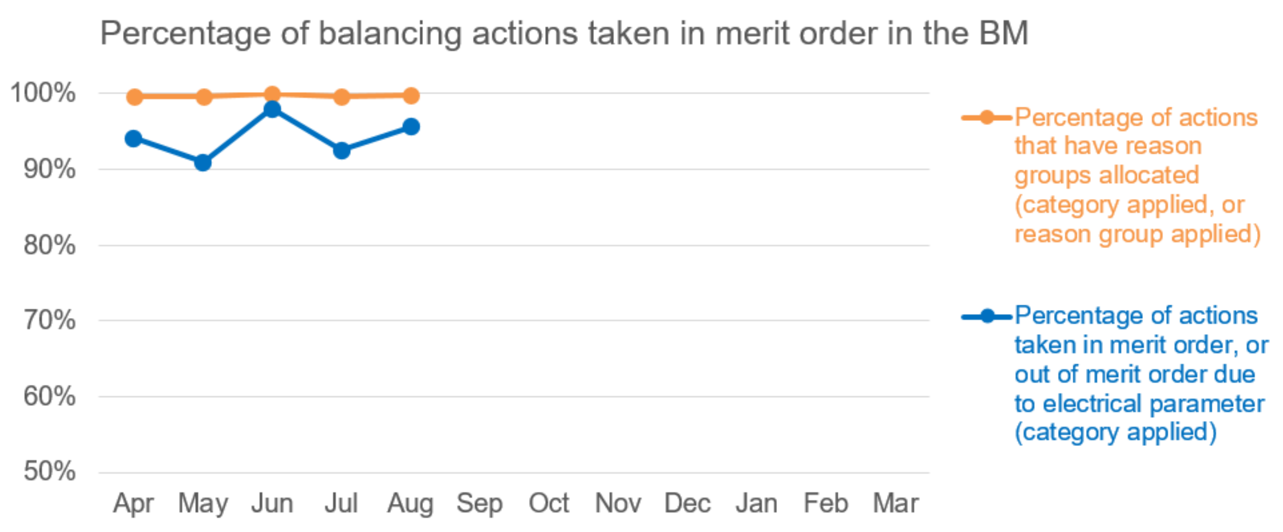


Table 5: Percentage of balancing actions taken outside of merit order in the BM

	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%							
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%							
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%	0.3%	0.2%							

Supporting information

August performance

This month 95.6% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. During August 2023, there were 56,181 BOAs (Bid Offer Acceptances) and of these, only 134 remain with no category or reason group identified, which is 0.2% of the total.

Future activities

As we continue to publish this dataset for BP2 we will also be developing the narrative to:

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

In next month’s report we will include an overview of the activities planned for the remainder of this year.

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.

August 2023-24 performance

Figure 6: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

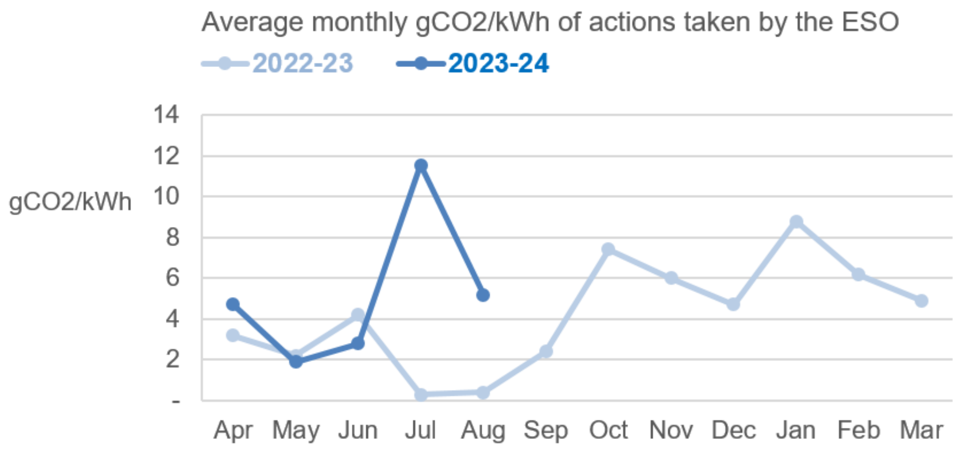


Table 6: Average monthly gCO2/kWh of actions taken by the ESO

	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							

Supporting information

Data issue: We are experiencing data issues for 1-8 Aug (incl.) which means carbon intensity after ESO actions is incorrect and almost identical to the FPN carbon intensity. Therefore, this month's narrative only covers 9-31 Aug. We are currently investigating the data issue to find the source of the problem.

In August 2023, the average carbon intensity of balancing actions was 5.16gCO2/kWh. This is 4.75g higher than August 2022 (which was 0.41gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 49% of settlement periods.

The greatest impact of ESO actions on carbon intensity was seen throughout the weekend of 12 and 13 August. A transmission outage for the weekend reduced a boundary constraint in Northern England by 2.7GW, requiring over 4GW of wind bids for much of Saturday. This bid volume reduced into the evening and overnight. Some of the outage was returned requiring significantly less bids on Sunday 13 August. However, numerous synchronous machines were required throughout Saturday and Sunday for voltage and inertia requirements.

Wind bids and interconnector actions were also required to increase downward regulation elsewhere. Three additional synchronous machines were required for the Sunday evening demand peak.

The lowest carbon intensity provided by the market was on the 19 August (~16gCO2/kWh) with high wind (~15GW) and solar (~7.5GW) providing around 75% of the generation mix. Synchronous units were required for voltage and inertia reasons raising the carbon intensity to ~50gCO2/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 ≤ f < 49.5	up to 60 seconds	2 times per year
48.8 < f < 49.2	Any	1-in-22 years
47.75 < f ≤ 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.

August 2023-24 performance

Table 7: 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							
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0							
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0							

Supporting information

August performance

There were no reportable voltage or frequency excursions in August.

[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.

August 2023-24 performance

Table 8: 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							
Integrated Energy Management System (IEMS)	0	0	0	0	0							

Table 9: 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							
Integrated Energy Management System (IEMS)	0	0	0	0	0							

Supporting information

August performance

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

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 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).

August 2023-24 performance

Figure 7: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

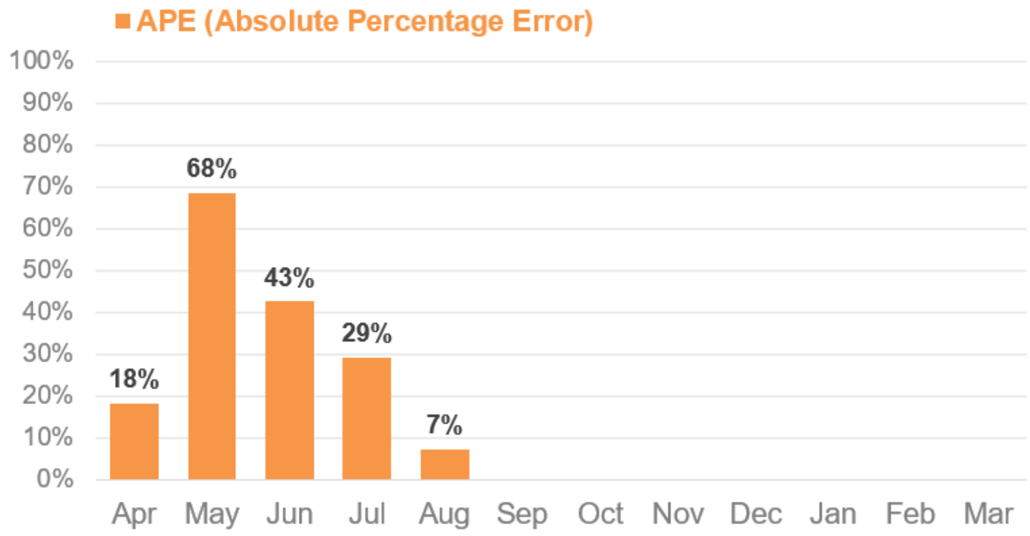


Table 10: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4							
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7							
APE (Absolute Percentage Error)[5]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**							

[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

August Performance:

Actuals out-turned above forecast in August 2023, but the Absolute Percentage Error (APE) decreased from 29% in July 2023 to 7% in August 2023. The main driver was constraint costs being higher than forecast.

Costs:

August outturn costs were around the 60th percentile of the forecast produced at the beginning of July.

Despite the average wholesale electricity price decreasing by 9% between the July forecast for August (£90/MWh) and August outturn (£82/MWh), constraint costs increased by 27% (£77m in July forecast and £98m for August outturn).

Forecast for August made at the start of July: £158m

Outturn costs for August: £172m

Volumes:

August actual volume was in line with July forecast.

Forecast for August made at the start of July: 20.2TWh

Outturn volume for August: 20.2TWh

Notable events during August 2023

Conclusion of Request For Information to support the design of the tender process for a mid-term (Y-1) market

We launched the Stability Market Design innovation project to explore the design for the enduring stability market with a focus on value for consumers. As a result of this work, in the April 2023 Markets Roadmap we set out the proposal to procure stability services across several timescales:

- Long-term Y-4
- Mid-term Y-1
- Short-term D-1

The first part of the Stability Market to launch is the mid-term (Y-1) market, with the intention to undertake the first tender round later this year (2023). To assist with the design and launch of the mid-term market an RFI was released on 17 July, seeking industry perspectives on a variety of topics. The RFI submission deadline was 18 August, and we are currently reviewing the feedback received. Once this has completed, we will be in a position to share more information about the next steps and our timeline for the Stability Mid-Term Market.

EAC Article 18 consultation closed and submitted to Ofgem for approval

The Enduring Auction Capability (EAC) is being designed to deliver co-optimised procurement for our day-ahead frequency response and reserve products. It is envisioned that this method of procurement will allow us to meet our needs in the most efficient way, while enabling providers to participate in multiple markets.

We proposed, for consultation, updated balancing services terms and conditions, to facilitate the launch of this new auction platform for procurement of Dynamic Containment, Dynamic Regulation and Dynamic Moderation (response services), and in due course for procurement of new 'quick' and 'slow' reserve services.

The industry consultation was undertaken from 14 June 2023 to 14 July 2023. Following the close of the consultation we reviewed and responded to feedback received from stakeholders and market participants. In addition, amendments were made to the proposed service terms and procurement rules that were launched as part of the consultation.

These amended documents were submitted to Ofgem for review on 14 August 2023 and we expect a result from them by mid-October 2023.

For more information please see our EAC site here.

DFS Article 18 consultation close, review and submission to Ofgem for approval

On 31 August we submitted our Demand Flexibility Service (DFS) Winter 23/24 Electricity Balancing Reserve (EBR) Article 18 consultation responses to Ofgem for approval. The consultation was on the terms and conditions of a revised DFS for this coming winter, in accordance with the requirements of EBR Article 18. The consultation created a huge response with 32 providers submitting detailed responses to the consultation.

On 7 September we held a post consultation webinar with industry to go over the consultation changes and our final draft proposals, 130 industry colleagues attended the webinar.

We are currently engaging with individual providers and industry forums to discuss the changes for winter 23/34 and the onboarding process for a go live date of 30 October, subject to Ofgem approval. We have introduced some automation options via an Application Programming Interface (API) for this winter’s service and we are talking to interested parties and carrying out some ongoing tests to make sure automations are working correctly.

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 August 2023

Electricity Ten Year Statement 2023

On 29 August, we published the 2023 Electricity Ten Year Statement (ETYS), which shows our view of GB's National Electricity Transmission System (NETS) over the next 10-20 years. This is an annual document which helps us to understand the future requirements of the system and where investment and development is needed to help us achieve our zero-carbon ambition.

This year's ETYS continues to highlight that over the next 10-20 years, we see increased requirements across some key network boundaries and as we strive towards Net Zero, the requirements of the system will continue to grow. In line with our ambition to expand ETYS to communicate a wider set of system needs, this year we have integrated our Voltage Screening results into ETYS. We also continue to showcase our work in year-round thermal analysis.

We're publishing ETYS earlier this year to allow more sufficient time for industry to review the system needs in advance of our network investment process. We've also received a direction from Ofgem allowing us to align the publication of the ETYS technical appendices with our second Transitional Centralised Strategic Network Plan (TCSNP2) publication, which is planned to be published this winter. This will allow us to ensure that our maps and data reflect the latest investment decisions made in TCSNP2.