ESO RIIO2 Business Plan 2 (2023-25)

January 2023-24 Incentives Report

23 February 2024

Contents

Introduction

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

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

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

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

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

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

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

Please see our website for more information.

Summary of Notable Events

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

- On 18 January, we confirmed over 2.2 million businesses and households have signed up to participate in the Demand Flexibility Service, along with 43 providers, eclipsing participation levels at this stage last year. In total, 2,507MWh have been saved across eight events, enough to power over 7.5 million homes for an hour. Further test events will be held until the end of March.
- The Local Constraint Market (LCM) is now live and operational after 8 months of successful trials. The LCM team hosted a webinar on 16 January to update providers on the LCM's progress. The webinar was well received by industry, and the LCM team continues to welcome feedback on the service.
- On 4 January, connection charging was successfully released into the new settlements and revenue billing system (STAR), which is the strategic platform for the ESO's billing and invoicing processes. This latest release enables annual charge setting and billing to run from STAR from January 2024 onwards with greater efficiency, compliance, and improved customer experience. The improvements for the customer include a greater level of breakdown of their connection charges and allowing the invoice and billing information to be e-mailed to multiple people.
- On 22 January, an automated solution to manage electricity supply and demand in case of a system fault, known as N-3 intertripping, went fully live. The solution is yet another positive step in the direction of achieving a zero-carbon future. It will allow renewable distributed energy resources to ensure energy generation and continued operability of the network until a real system fault happens.
- On 23 January, we held our annual Operability Strategy Report webinar, following on from publication of the report. The webinar was well received, scoring 4 out of 5 for useful content and 90% of attendees learnt something new. The webinar recording, report and Q&A document are available on the website.

Summary of Metrics and RREs

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

Metric/RRE		Performance	Status
Metric 1A	**Balancing Costs**	£202m vs benchmark of £276m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 651MW vs indicative benchmark of 669MW	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 6.82% vs indicative benchmark of 5.81%	●
Metric 1D	**Short Notice Changes to Planned Outages**	2.1 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**	87.8% of actions taken in merit order or driven by an electrical parameter	N/A
RRE 1G	**Carbon intensity of ESO actions**	6.6gCO_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 12.7%	N/A

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

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

Adelle Wainwright
Interim Head of Regulation

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:

i. The benchmark was created using monthly data from the preceding 3 years.
ii. A straight-line relationship has been established between historic constraint costs, outturn wind generation and the historic wholesale day ahead price of electricity.
iii. A straight-line relationship established between historic non-constraint costs and the historic wholesale day ahead price of electricity.
iv. Ex-post actual data 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 = 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.

January 2023-24 performance

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

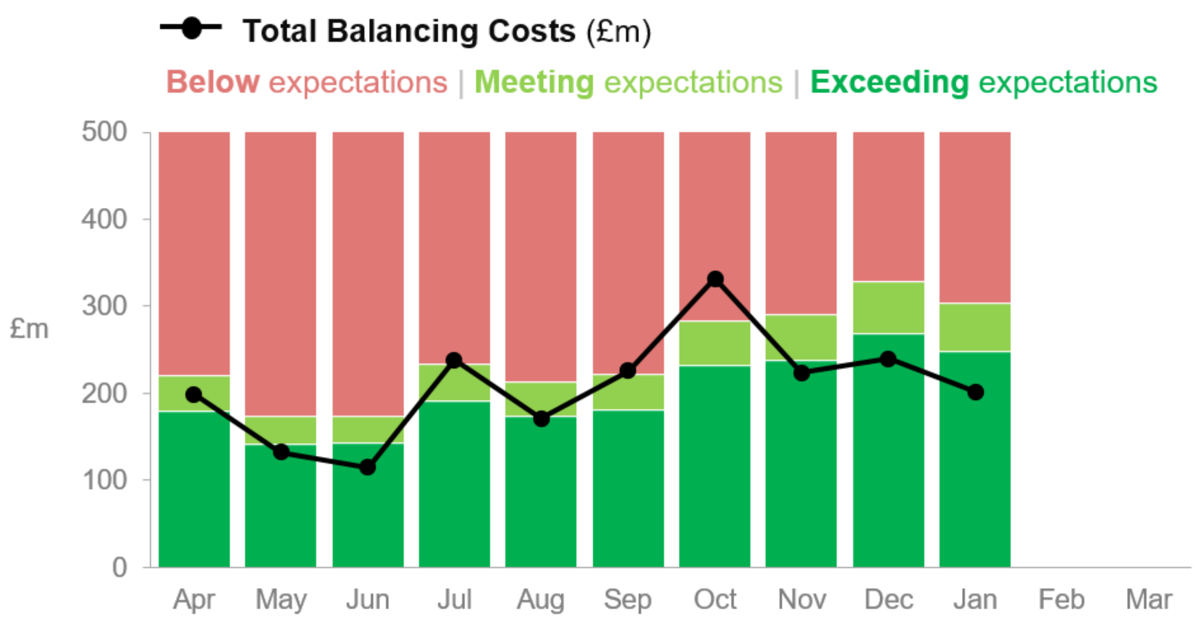


Table 3: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4	4.6	3.8	4.2	6.2	6.1	8.3	7.4			48.98
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86	83	89	99	74	74			n/a
Benchmark	200	157	158	212	194	201	258	264	299	276			2218
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**	**226**	332	224	240	202			**2079**
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

Ongoing data issue:

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

We continue to investigate and will advise when we have a resolution.

This month's benchmark

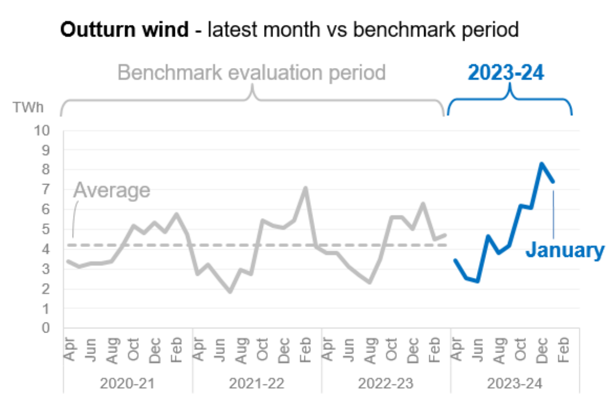
As noted in the introduction to this section, a new benchmark was introduced for BP2. The benchmark is derived using the historical relationships between two drivers (wholesale price and outturn wind generation) and balancing costs.

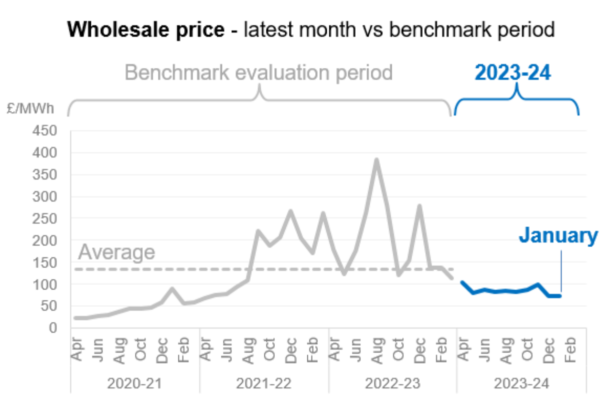
The January benchmark of £276m is the second highest so far in 2023-24, and this reflects:

- an **outturn wind** figure that remains high compared to the benchmark evaluation period (the last three years), although slightly lower than last month. It is still higher than the highest outturn wind (7.1TWh) in the entire benchmark period.

- No significant change in the average monthly **wholesale price** (Day Ahead Baseload) this month compared to December 2023, remaining at the lowest point it's been so far in 2023-24. It is also relatively low compared to the benchmark evaluation period (the last three years). Despite a steady wholesale price this month, the slight decrease in the overall benchmark reflects the impact of the relatively lower levels of wind generation 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.





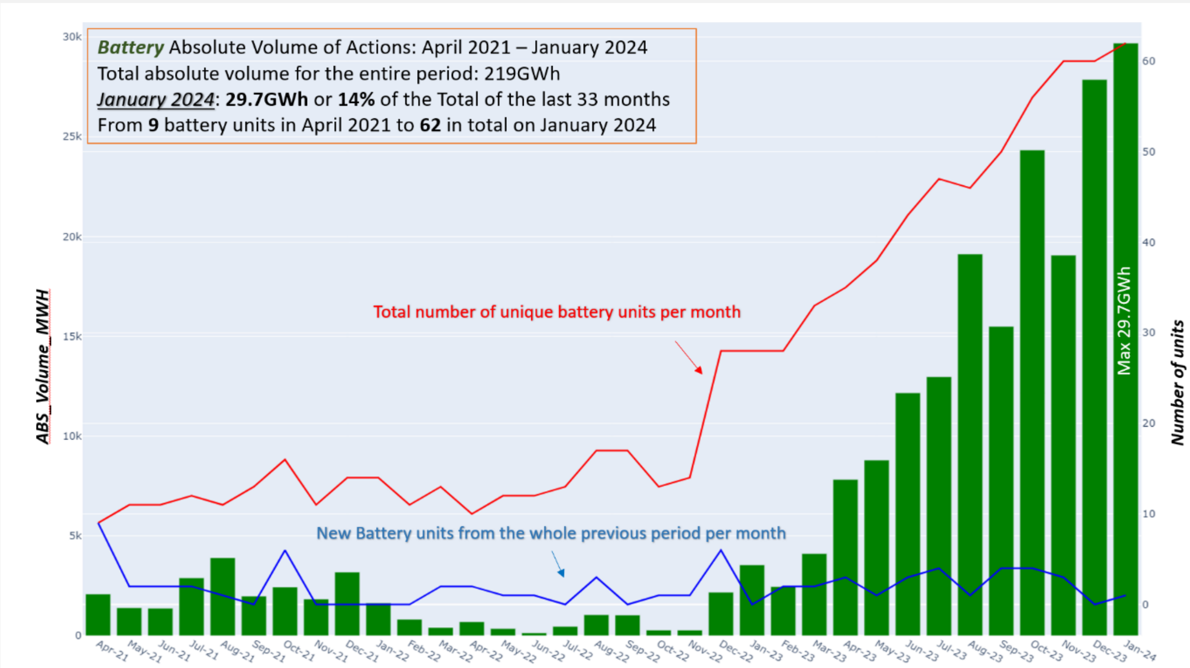
January Performance

January's total balancing costs were £202m which is £74m (~27%) below the benchmark of £276m, and therefore performance is exceeding expectations. This is the third consecutive month and sixth time that the ESO has 'exceeded expectations' since April 2023. January's overall outturn wind was slightly lower than December 2023, although still significantly higher than the rest of the months in 2023-2024. The volume weighted average price for bids have increased compared to last month by £5.5 per MWh, but remains lower than the previous three months, however, the volume weighted average price for offers decreased following the trajectory of the energy prices.

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. January had the highest battery dispatch volume (~30GWh) since April 2021 as show on the graph below. This illustrates our commitment to maximising the flexibility of energy offered by battery storage over the last year.

As the graph illustrates, we have been focussed on increasing the utilisation of storage assets. We continue to utilise the Open Balancing Platform phase 1 in December this year which has enabled 'Bulk Dispatch', a new tool that means control room engineers can send hundreds of instructions to smaller Balancing Mechanism Units and battery storage units at the press of a button.

April 21 to January 24 - Monthly Volume of actions for Batteries and number of unique units



Despite low-cost conditions for January 2024 – with less wind generation, and lower total constraint volumes compared to December, the constraint cost in Scotland increased by 62.7GWh and Cheviot by 85.7GWh with a total increase of 148.4GWh by actions and £14.8m by costs. However, we were still able to make a significant total amount of savings through optimizing outages and trading activities.

The total savings from outage optimisation were £447m in January. This is a significant amount of savings made this month. Some of these savings are from long-term actions, such as those taken to minimise costs from a nine-week outage for various major works that were originally planned and occurred in January. This included the repair of cables in the Severn tunnel, which would cause significant voltage issues in the South Wales network. This would usually require the contracting of a Pembroke machine at its SEL (220 MW) for the 8-9 weeks of the outage. However, the outage optimisation team were able to generate savings by disconnecting certain circuits and expediting the return and service of another circuit to support the South Wales network (£23m in savings). Other shorter-term actions taken to generate savings on the network include the rejection of an outage on the weekend of 20/01/2024 at the Black Hillock Kintore 275 kV to avoid high constraint costs (£390k in savings).

The most significant outage saving however, came from a 2-week outage on MOFF - ELVA that was rejected from aligning with an ELVA – GRNA outage. These are two locations on the B6 boundary, and this movement has resulted in a significant increase in availability through the network. The B6 boundary is normally at a 4500 MW limit with MOFF - ELVA on outage. In the original placement, there would be a 2 week overlap between MOFF - ELVA and ELVA - GRNA. The next double circuit Blyth - Eccles - Stella West can then only be secured by 'floating' Scotland (meaning to set the boundary transfer to 0MW). Therefore 4500 MW of boundary capability would be lost every hour for a 2-week duration. This is approximately 1.5 TWh of additional energy made available from the ESO rejecting the proposal made by TO, hence the significant cost saving enabled by this action.

The Trading team were also able to make significant savings through commercial decisions with interconnectors. A total of £38.7m was saved by taking these actions compared to alternative BM actions.

Work is still ongoing in quantifying the value of savings from the Operational Balancing Platform, but as can be seen from the figure above, a record volume of batteries (29.7 GWh) was dispatched through the Balancing Mechanism in January 2024.

As mentioned last month, the ESO are seeing an increase in costs associated with the short-notice of down-rating by TOs ('hot-joints'). On the 27 January, another significant downrating at the Lackenby-Norton 400kV line meant that constraints on the SSHARN7 boundary were more severe than if the line wasn't downrated. This resulted in an increase in costs at this boundary on this day of a little over £5m.

Breakdown of costs vs previous month

Balancing Costs variance (£m): January 2024 vs December 2023

		(a) Dec-23	(b) Jan-24	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	5.0	8.7	3.8	
	Operating Reserve	27.7	16.4	(11.2)	
	STOR	9.2	5.0	(4.3)	
	Negative Reserve	1.8	0.4	(1.3)	
	Fast Reserve	13.3	15.3	2.0	
	Response	15.8	14.8	(1.0)	
	Other Reserve	2.5	2.3	(0.2)	
	Reactive	16.1	13.9	(2.2)	
	Restoration	4.6	3.8	(0.8)	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	8.7	5.5	(3.2)	
Constraint Costs	Constraints - E&W	50.3	21.3	(29.0)	
	Constraints - Cheviot	0.1	10.6	10.5	
	Constraints - Scotland	48.5	63.3	14.8	
	Constraints - Ancillary	0.2	0.2	0.0	
	ROCOF	5.4	1.3	(4.0)	
	Constraints Sterilised HR	31.2	18.6	(12.6)	
Totals	Non-Constraint Costs - TOTAL	104.5	86.1	(18.4)	
	Constraint Costs - TOTAL	135.6	115.3	(20.3)	
	Total Balancing Costs	**240.1**	**201.5**	**(38.7)**	

As shown in the total rows from the table above, both non-constraint & constraint costs decreased by £18.4m & £20.3m respectively, resulting in an overall decrease of £38.7m compared to December 2023.

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

- **Constraint-Scotland & Cheviot***: The constraint cost increased by £25.3m, because the volume of actions increased by 148GWh.
- **Constraint-England & Wales***: a drop of 58GWh in volume of the total actions with the constraint cost decreased by £29m, mainly due to a decrease in the import constraint actions by 197GWh for voltage control and to support system inertia.
- **Constraints Sterilised Headroom***: £12.6m decrease, and the total volume of replacement energy slightly decreased by 18GWh.

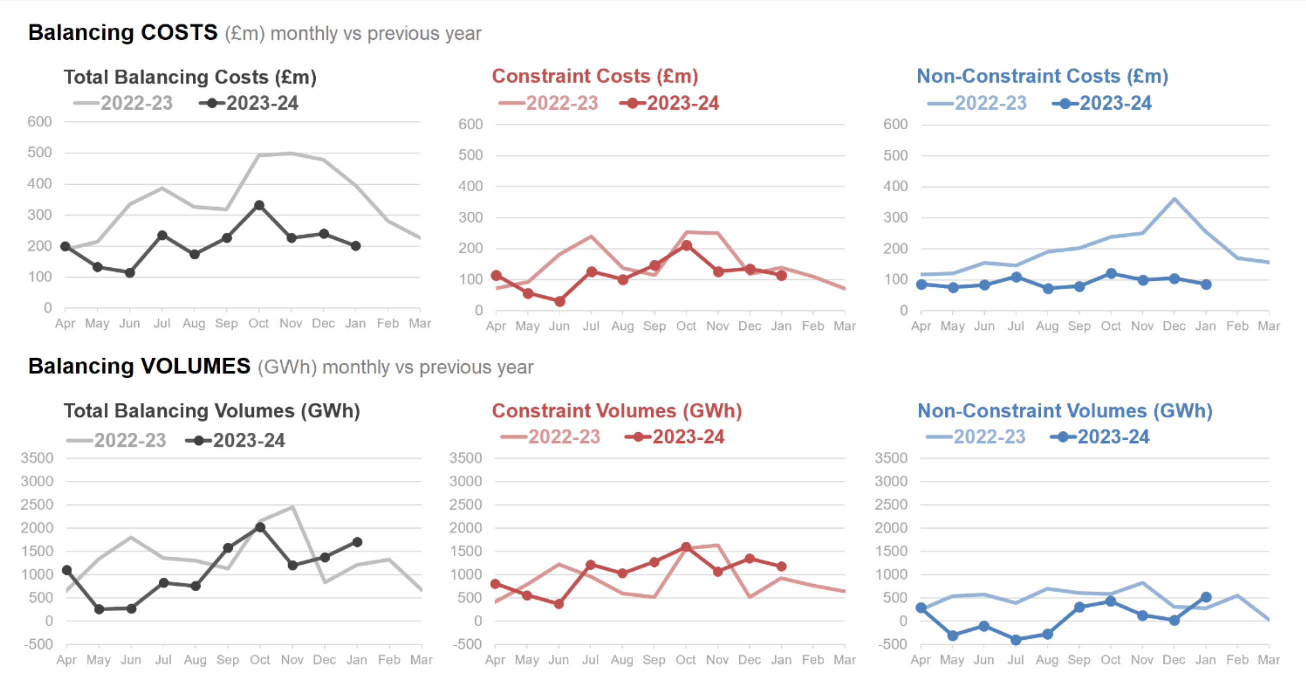
*79 more planned outages compared to last month yet remain lower than the previous months in 2023-2024. A relatively low number of planned outages tends to be the case during the winter months in preparation for peak demand conditions. This month also sees a slight increase of the volume weighted average price for bids and offers following the minor downward trajectory of electricity prices of the month.

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

- **STOR**: £4.3m decrease, with a slight increase of 6.5GWh volume of actions from the BM*.
- **Operating Reserve**: £11.2m decrease despite using 163GWh more reserve required to secure the system.

*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



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

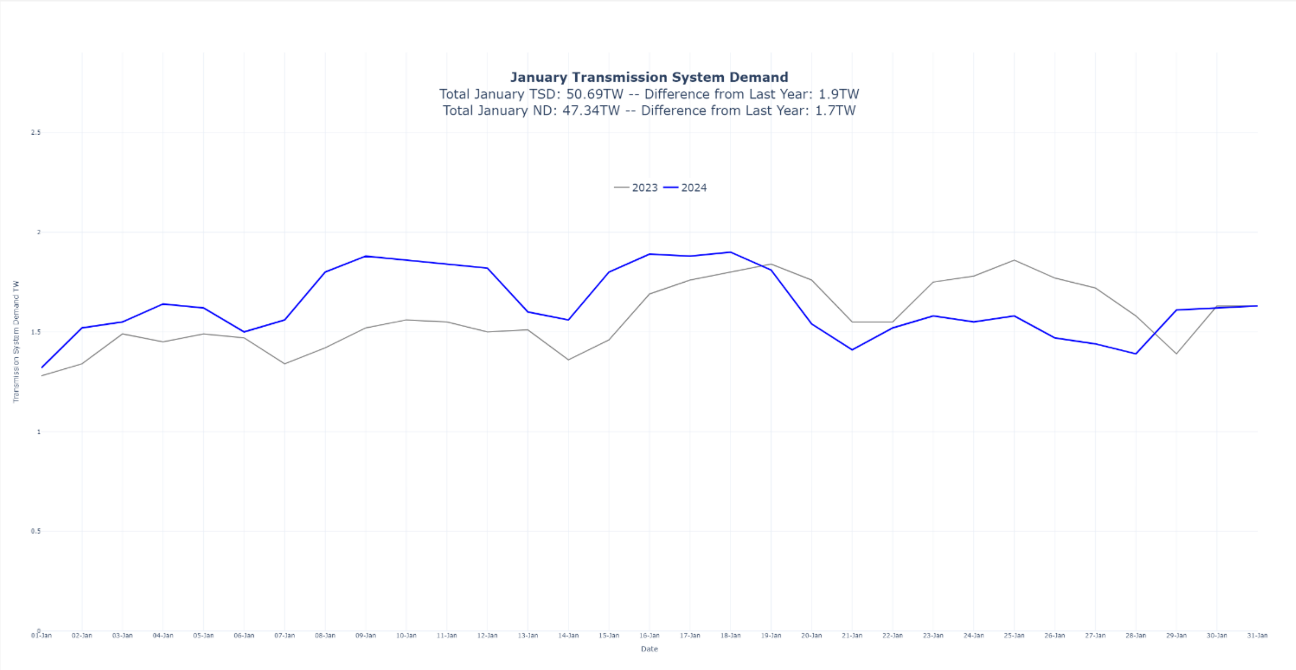
Constraint costs	
Compared with the same month of the previous year:	Constraint costs were £23.9m lower than in January 2023, despite the volume of constraint actions increased by 257GWh.
Compared with last month:	Constraint costs were £20.3m lower than in December 2023, because of 170GWh lower volume of constraint actions, driven by slightly lower outturn wind.
Non-constraint costs**	
Compared with the same month of the previous year:	Non-Constraint costs were £156m lower than in January 2023 due to: • Significantly lower average wholesale prices* • 244GWh higher Volume of actions.
Compared with last month:	Non-Constraint costs were £18.4m lower than in December 2023, despite 500GWh more absolute volume of actions were required to balance the system.

* Average wholesale price for January 24: £74/MWh compared to £137/MWh for January 23.

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

January daily Transmission System Demand (TSD*)

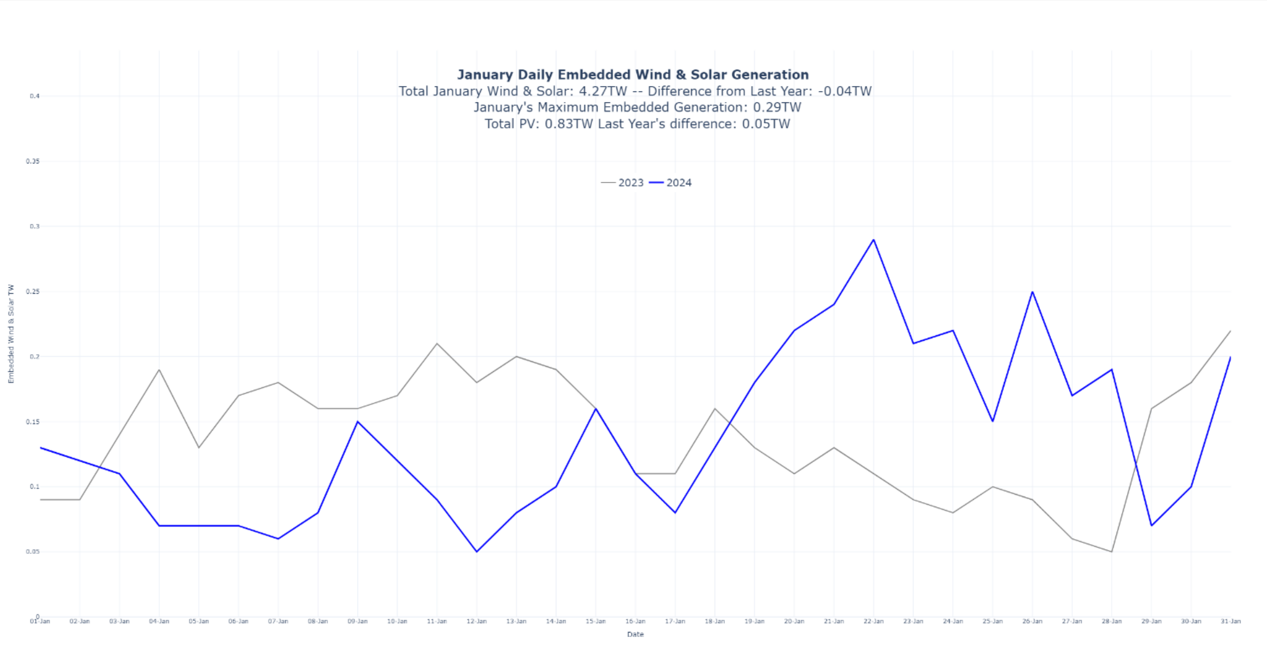
- **National Demand** (not shown below) was 1.7TW higher than January 2023
- **Transmission System Demand*** was 1.9TW higher than January 2023.



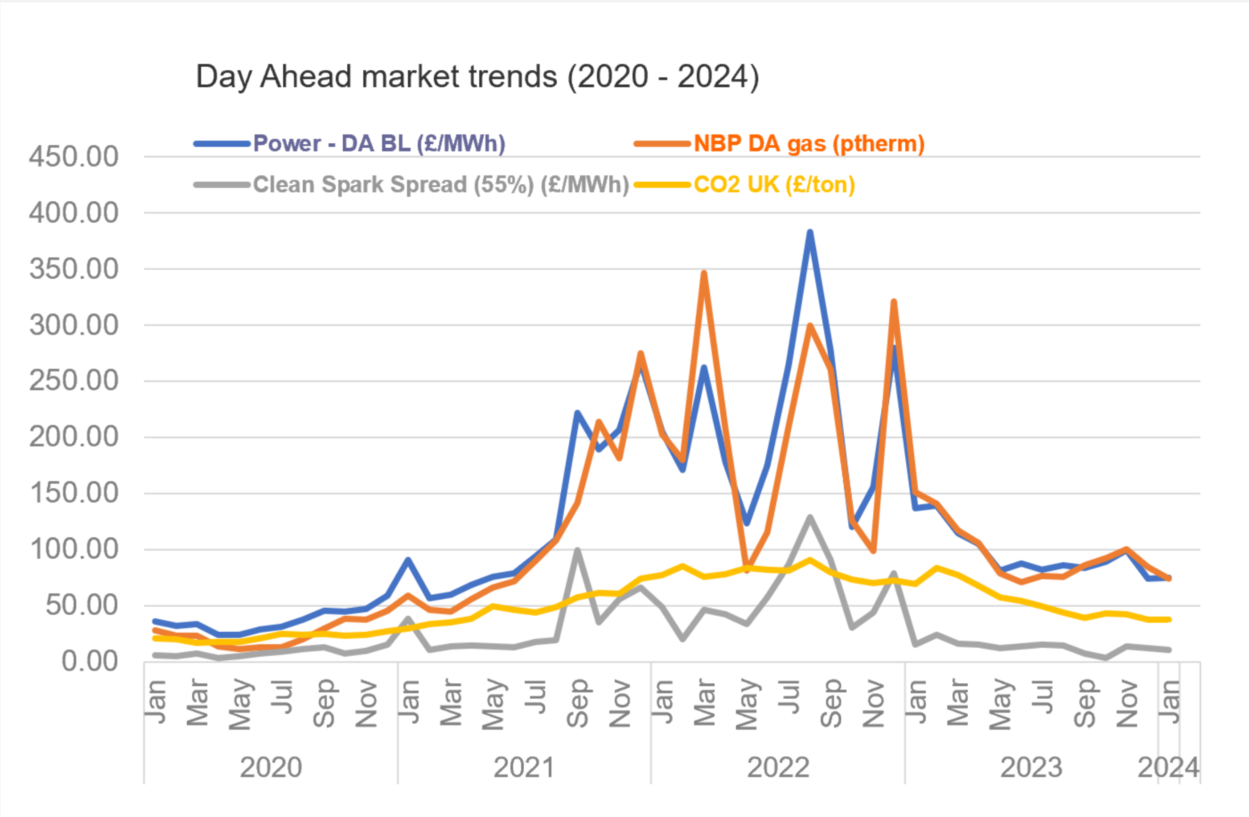
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

January daily Embedded Wind and Solar Generation

- **Embedded wind & solar generation** was 0.04TW lower than January 2023. The maximum embedded wind & solar generation occurred on January 22 (0.29TW).



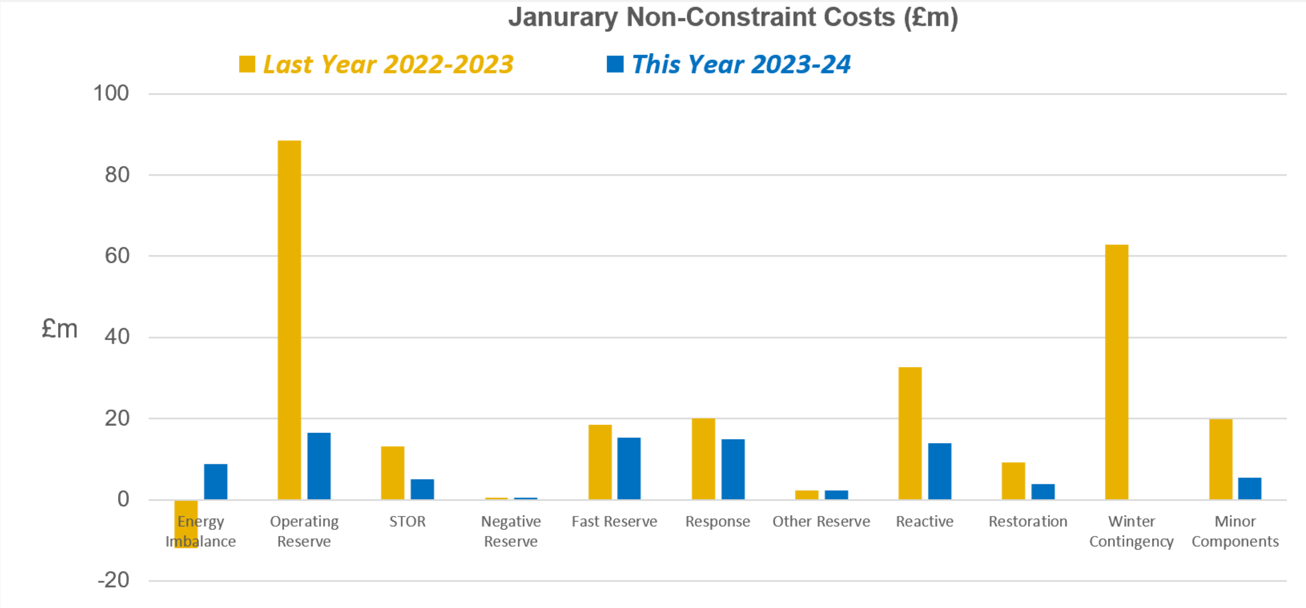
Price Trends in energy markets



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

All the trends had a downward trajectory compared to last month, despite the change in power price is very small. They all 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 January 2024 with those of January 2023, most categories showed a decrease or a small deviation:

- **Energy Imbalance** £20.7m increase due to 63GWh more volume of actions taken to balance the system.
- **Operating Reserve** £72m decrease mainly due to the significant downward trajectory we have observed in all the energy related prices.
- **Reactive** £18.8m decrease, due to a significant drop in the weighted average price, from £12 per MVAR to £4.5 per MVAR.
- **Minor Components** decreased by £14.2m. 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

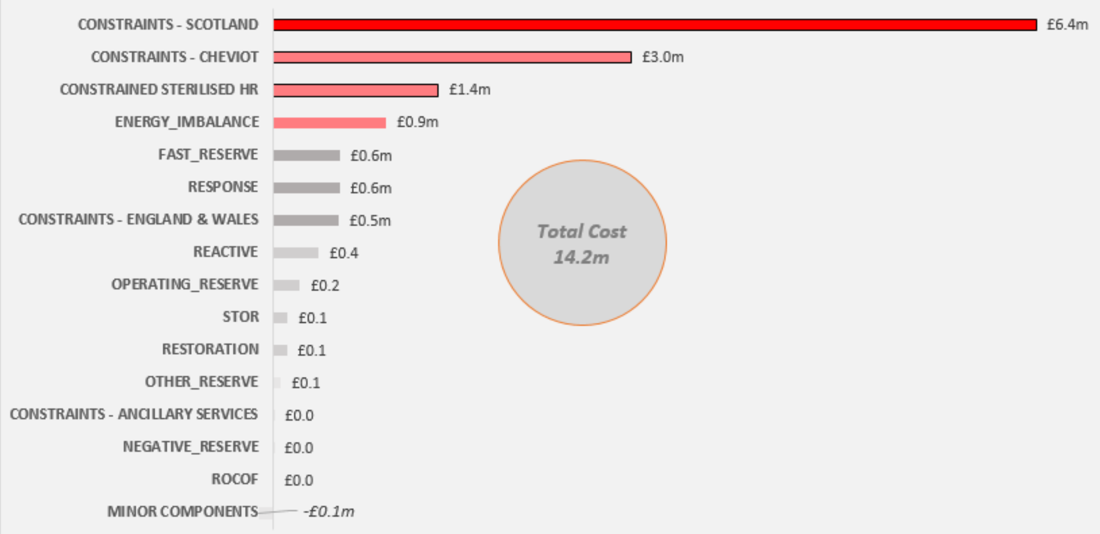
Margin prices (the amount paid for one MWh) have decreased compared to December 2023, and is also significantly lower than the corresponding period of the previous year.

Daily Costs Trends

January's balancing costs were £38.7m lower than the previous month, none of the days were recorded with costs above £15m with around 23% of the days had a daily total cost over £10m, resulting in a decrease of the average monthly daily cost by £1.2m (from £7.8m to £6.6m).

The lowest total daily cost of £1.8m was observed on 9 January, whilst the highest total cost was observed on 28 January when the total spend was £14.2m, constraints in Scotland area were the major cost component driven by high renewable generation and low demand. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs for the day.

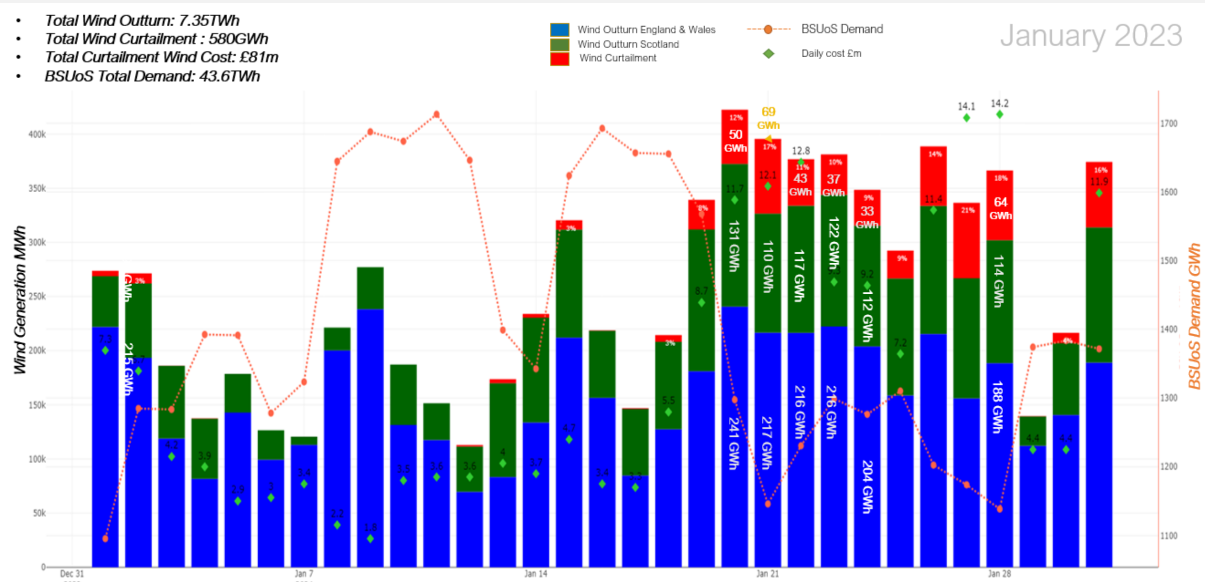
Cost breakdown for 28 January 2024



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

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

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



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

Metric 1B Demand forecasting accuracy

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

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

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

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

January 2023-24 performance

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

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

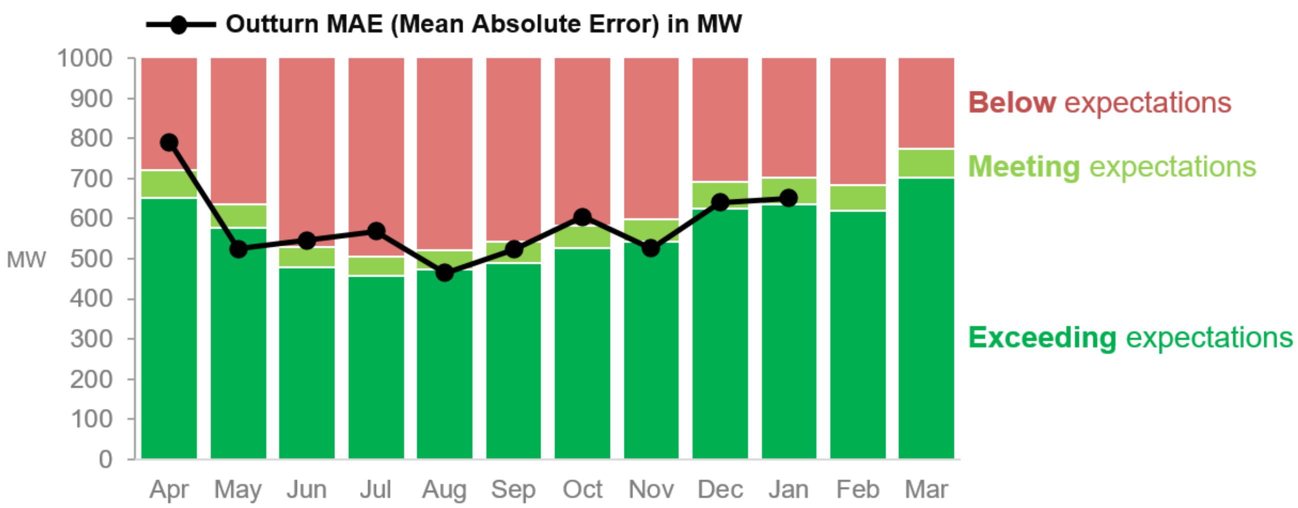


Table 4: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738
Absolute error (MW)	**791**	**523**	**546**	**569**	**465**	**523**	**604**	**526**	**640**	**651**		
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 January, the mean absolute error (MAE) of our day ahead demand forecast was 651 MW compared to the indicative 'meeting expectations' target of 702 MW, and indicative 'exceeding expectations' target of 636 MW.

The weather in January was largely mild, with a very cold spell during the middle of the month. Peak demand outturn occurred on 15 January (45.1GW), which is likely to remain the peak Winter demand for 2023-24.

The forecasting performance in January was largely influenced by three poor days. New Years Day, along with 8 & 10.

Both Monday 8 and Wednesday 10 Jan – two of the higher error days - were affected by solar forecast errors, but weather forecast errors (temperature and wind speed) were also a factor.

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	312	21%
1500 MW	84	6%
2000 MW	41	3%
2500 MW	23	2%
3000 MW	12	1%

A DFS test was run on 17 Jan. This will have affected the national demand outturn but is not included in our forecasts.

Missed / late publications

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

Triads

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

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

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

In January we observed 7 days affected by triad avoidance behaviour – 8, 9, 10, 15, 16, 17 and 18 Jan, where there was an average of 550 MW suppression over the darkness peak period.

Metric 1C Wind forecasting accuracy

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

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

January 2023-24 performance

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

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

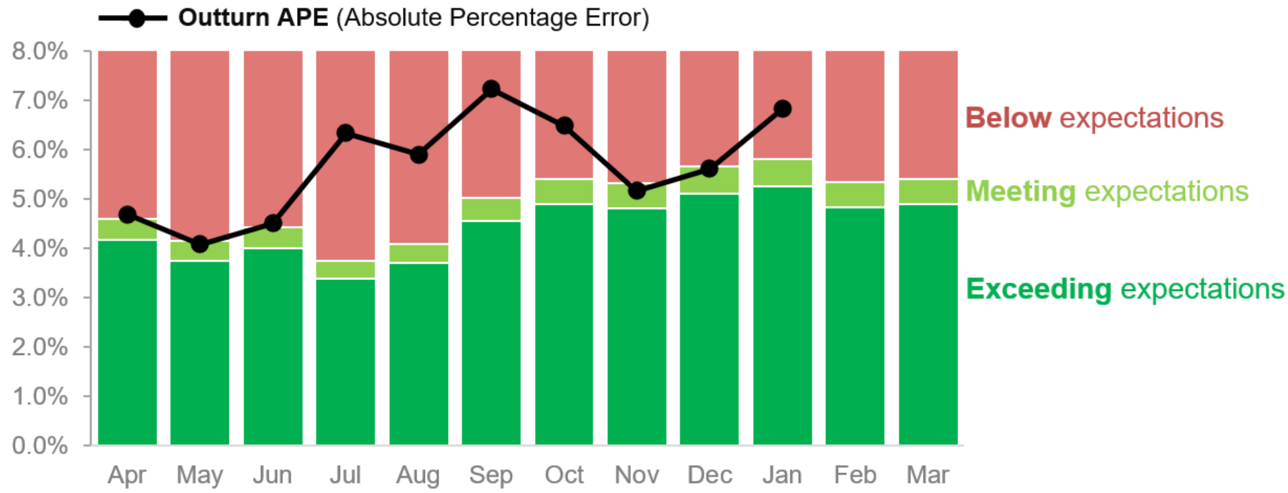


Table 5: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Indicative benchmark (%)	4.38	3.95	4.21	3.57	3.89	4.79	5.15	5.06	5.38	5.81	5.08	5.14
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**	**6.48**	**5.16**	**5.61**	**6.82**		
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

Forecasting accuracy was largely affected by the weather data and the timing of numerous storms passing over GB. Three extreme error days (New Years Day – influenced by Storm *Henk*, 9 and 14 January) and the severe impact of the back-to-back Storms *Isha* and *Jocelyn* during (21-24 January), unfortunately curtailed forecasting performance.

While the occurrence was predicted in the forecast, an unprecedented ~9GW (estimated) of wind cut-off happened during Storm *Isha*. Forecast weather conditions got progressively worse as the storm approached, with extreme wind speeds experienced across most of the country.

Although January was disappointing, the general trend of performance is improving, with the best day reporting <2% MAE. Windfarm outage data (when submitted by Market Participants) is now being used in the forecasts. Work continues to improve cut-out modelling, through industry liaison (Wind Advisory Group) and model enhancement.

Moray East 3 (300MW) came online this month and continues commissioning.

For the month of January the wind power forecast accuracy attained was 6.82%, against a target of 5.81%.

Withdrawal of wind units

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

Missed / late publications

In January 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.

January 2023-24 performance

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

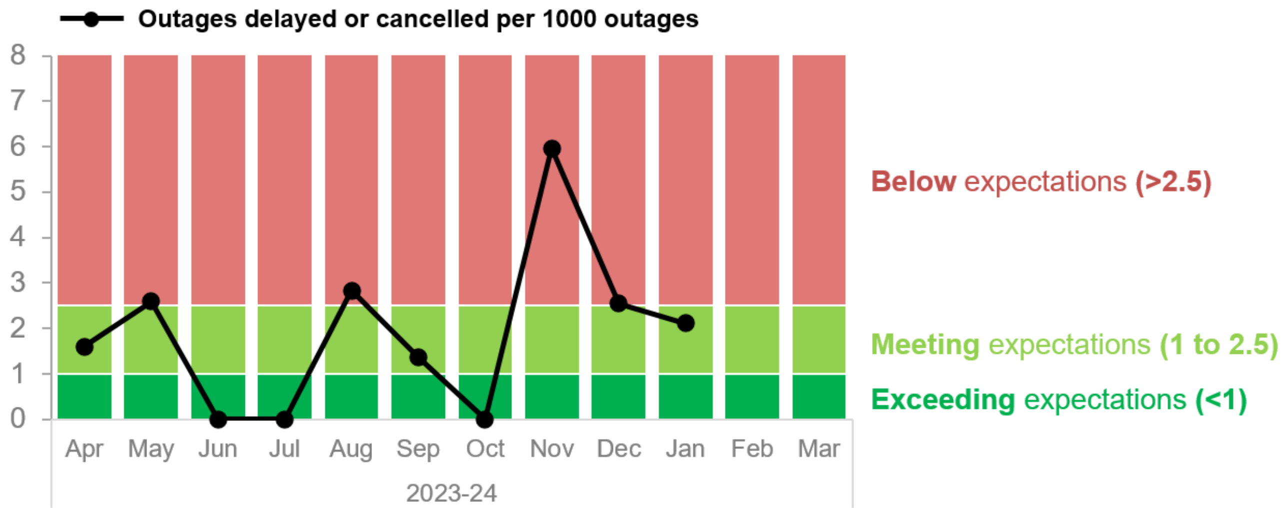


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734	704	671	393	472			6332
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1	0	4	1	1			12
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4	0	6	2.5	2.1			1.90
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 January, the ESO has successfully released 472 outages. There was one delay or cancellation due to an ESO process failure. The number of stoppages or delays per 1000 outages for January was 2.12, which is within the ‘Meets Expectations’ target of less than 2.5. The cumulative number of stoppages or delays per 1000 outages to date is 1.90 which is within ‘Meets Expectation’s target. The single event can be summarised below:

There was a delay on an outage as the proposed substation running arrangement from the planning department could not be achieved due to an inoperable isolator. The original substation configuration was agreed with the Distribution Network Operator (DNO) and this technical limitation resulted in greater risk to the demand. Therefore, the outage was delayed until a new agreement could be reached with the DNO. It was identified that this technical limitation on the isolator had been declared by the Transmission Owner (TO) after the standard checks are performed by the outage planning department and this was missed. As a preventative action, a new check has been implemented before the end of the planning phase to ensure no new technical limitations have been raised or missed in the future.

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 economic dispatch decisions being taken within the BM given the status of the power system, while providing significant insight as to why those actions have been taken. 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 to secure the power system 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

January 2023-24 performance

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

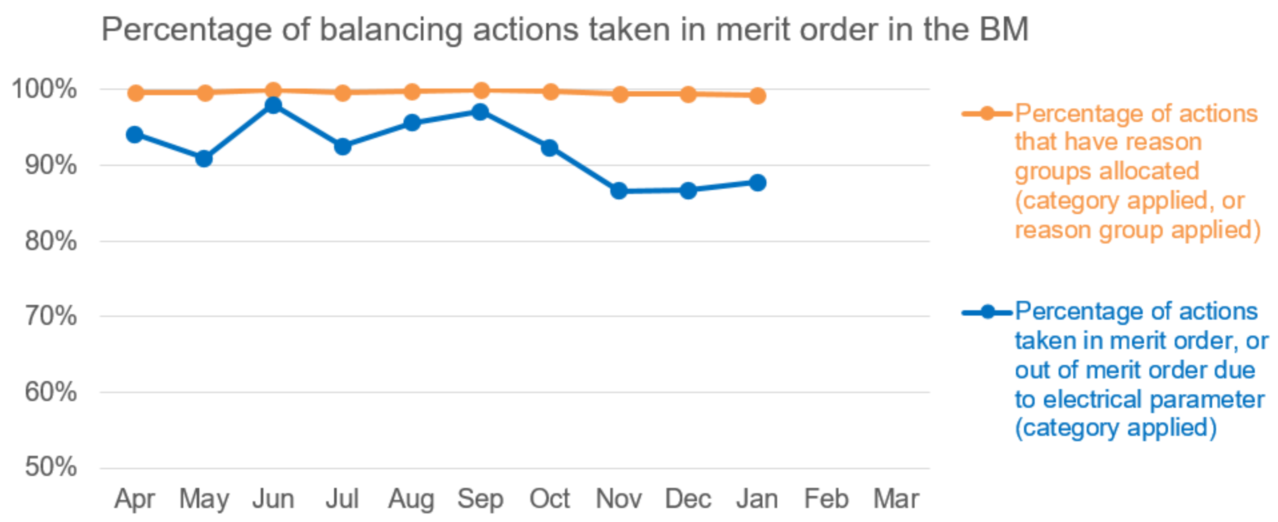


Table 7: Percentage of balancing actions taken outside of merit order in the BM

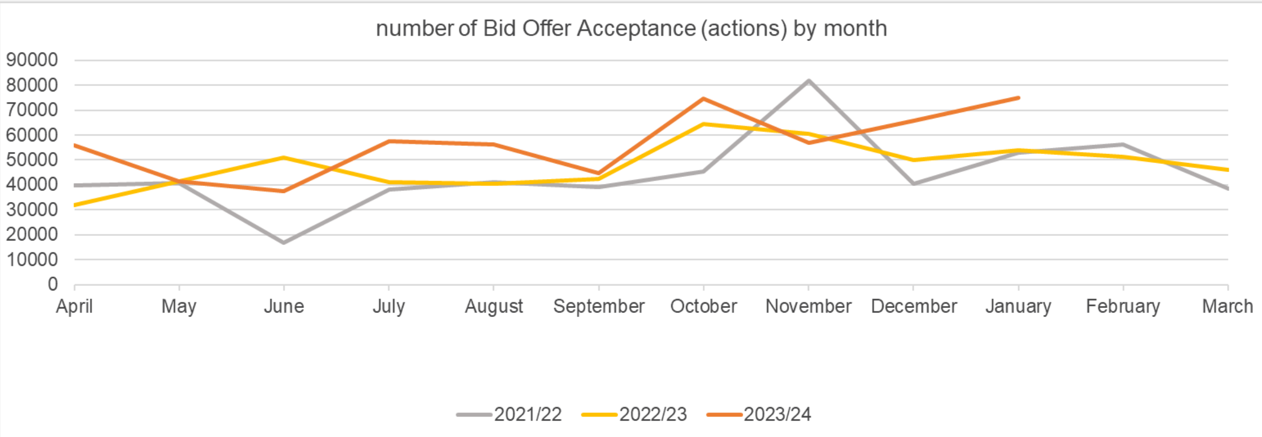
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	94.1%	90.9%	98.0%	92.5%	95.6%	97.1%	92.3%	86.6%	86.7%	87.8%		
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.6%	99.9%	99.7%	99.8%	99.9%	99.8%	99.5%	99.5%	99.2%		
Percentage of actions with no category applied or reason group identified	0.3%	0.4%	0.1%	0.3%	0.2%	0.1%	0.2%	0.5%	0.5%	0.8%		

Supporting information

January performance

This month 87.8% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. 11.4% 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 January, there were 74929 BOA (Bid Offer Acceptances) and of these, only 621 remain with no category or reason group identified, which is 0.8% of the total.

The number of BOA's will always vary from day to day and month to month in response to the system needs. However, numbers overall are significantly higher for the first 10 months of the current financial year reaching 98% of the total for the previous year and 6% higher than the total of 2021/22. This appears to reflect the control engineers' increasing use of combinations of more economic smaller units to provide services within the Balancing Mechanism. We expect this trend to continue following the implementation of the Open Balancing Platform in December 2023.



Other activities

We continue to closely support LCP for the second phase of their independent analysis to provide greater insight into how the data can be used to identify and explain the reasons for out of merit despatch decisions.

We are developing the detailed plans for delivery of the improvements for Dispatch Transparency data, to incorporate the outcomes of the LCP analysis and continue to improve understanding and reporting. More information on this improvement timeline plus how we intend to engage with wider industry going forward and on an enduring basis will be provided at the follow-up storage webinar following LCP completion of the second phase work, expected March 2024.

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

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.

January 2023-24 performance

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

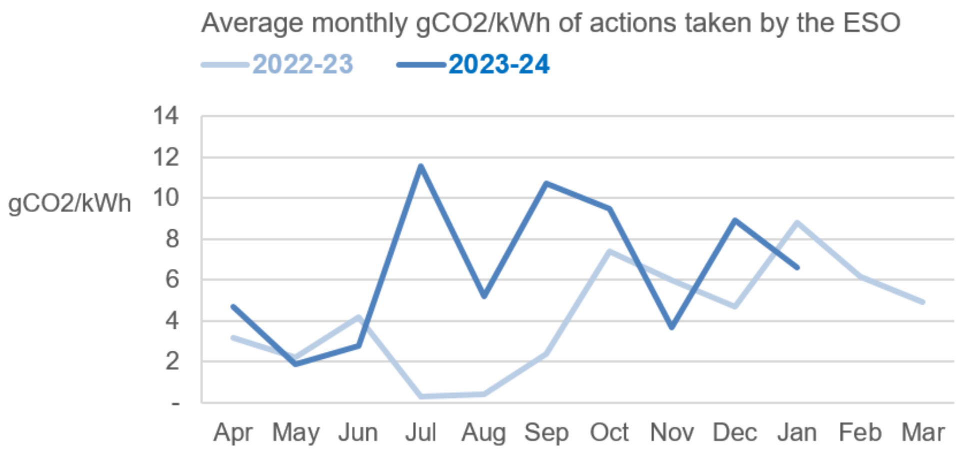


Table 8: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	4.7	1.9	2.8	11.6	5.2*	10.7*	9.5*	3.7	8.9	6.6		

Supporting information

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

In January, the average carbon intensity of balancing actions was 6.6gCO2/kWh. This is 2.2g lower than January 2023 (which was 8.8gCO2/kWh).

Across the month, ESO actions reduced the carbon intensity in 36% of settlement periods.

The ESO had very little impact on carbon intensity from 1 to 19 January. The average carbon intensity of balancing actions during this period was 0.6gCO2/kWh. Decreasing wind levels through this period meant more gas units were required by the market to meet demand, meeting our system needs at the same time. However, the generation from gas units fluctuated widely on a daily basis through the period. For example, on the 14

January, gas generation decreased by ~12GW to 3GW in 8 hours; this was then followed by an increase to 18GW in 6hours. Despite this, we continued to operate the system without significant impact on carbon intensity, keeping the average to +1.3gCO2/kWh.

The greatest impact of ESO actions on carbon intensity was seen over the weekend of 27-28 January, raising the carbon intensity by 34g on average across the weekend. High winds in North Scotland led to a yellow weather warning and up to 4GW of bids on wind units to resolve north to south transmission constraints. Constraints in Scotland and Northern England required 4.6GW of wind bids to solve. Pump Storage assets were used to reduce volume of constrained wind but this was restricted once the lakes were full. A number of fossil units were run to replace the constrained wind including 4 units for voltage reasons. Transmission outages prevented other operational actions being used for voltage control and required an additional fossil unit to support system volts. A number of interconnector issues also led to the loss of up to 500MW of import, requiring replacement on fossil units.

The lowest carbon intensity provided by the market was on the 23 January 22:00-22:30 (39gCO2/kWh) with high wind (~19GW) and other zero carbon sources providing around 80% of the generation mix (after ESO actions). Ten fossil units were required to meeting voltage needs with a further unit to provide additional inertia, which raised the carbon intensity to ~85gCO2/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.

January 2023-24 performance

Table 9: Frequency and voltage excursions (2023-24)

	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0	0	0	0		
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0	0	0	1	0		
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0		

Supporting information

January performance

There were no reportable voltage or frequency excursions in January.

[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.

January 2023-24 performance

Table 10: 2023-24 Unplanned CNI System Outages (Number and length of each outage)

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

Table 11: 2023-24 Planned CNI System Outages (Number and length of each outage)

	2023-24											
Planned	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	1 outage (185 mins)	0	0	1 outage (265 mins)	1 outage (145 mins)	1 outage (170 mins)	0	1 outage (203 mins)		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0		

Supporting information

January performance

In January, 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.

There were no other planned outages during January.

There were no unplanned outages during January.

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).

January 2023-24 performance

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

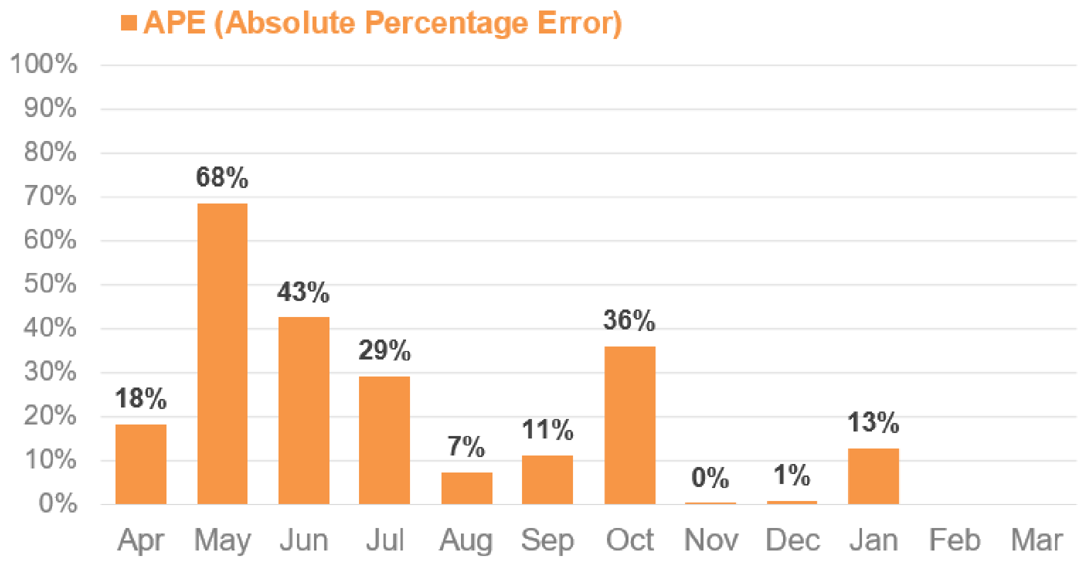


Table 12: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[4] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4	12.8	16.5	10.5	10.6	8.9		
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4	10.6	10.5	10.6	10.0		
APE (Absolute Percentage Error)[5]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**	**36.0**	**0.0**	**0.7**	**12.7**		

[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

January Performance:

Actuals out-turned below forecast for January, with an Absolute Percentage Error of 12.7%.

The increase in absolute percentage error from last month was a result of below forecast costs and above forecast volume both resulting in a reduced £/MWh.

Costs:

January outturn costs were around the 45th percentile of the forecast produced at the beginning of December. There was an 8% decrease in average wholesale electricity price between the December forecast for January (£78/MWh) and January outturn (£72/MWh).

Volumes:

January actual volume was above the December forecast.

Forecast for January made at the start of December: 26.1TWh

Outturn volume for January: 27.2TWh

Notable events during January 2024

2.2 million sign up to Demand Flexibility Service

On 18 January, following confirmation of market data, we can now confirm the outcomes of the first 6 test events and 2 live events held across November and December 2023. So far over 2.2 million businesses and households have signed up to participate in the Demand Flexibility Service, along with 43 providers, eclipsing participation levels at this stage last year. Across the 8 total events held in 2023 consumer households and businesses have saved a total of 2,507MWh, enough to power over 7.5million households during these events, roughly 27% of GB households.

This year's Demand Flexibility Service launched in November 2023, and since then, we have run seven test events to encourage participation and gain insights into demand flexibility. Alongside these events, two live events were held to balance operational margins on the national electricity network. The results are impressive, with over 2,507MWh delivered across the six tests and two live events, enough to power over 7.5 million homes for an hour. The British public and commercial industries have shown strong support for the service, as seen in the response to the two live events held on 29 November and 1 December. Participants delivered an average of 497MWh across each hour and a half session, enough to power nearly 1.5 million homes. We have also introduced within-day as well as day-ahead test notifications for winter 23/24, allowing for shorter notice to ask consumer households and businesses to change their electricity usage. We have plans to hold further test events until the end of March to promote further learning from the Demand Flexibility Service. Overall, the service has made a significant impact and is a great achievement for the team.

Local Constraint Market webinar following go live success

Local Constraint Market (LCM) is a world first for the ESO in employing an established and open-markets platform to enable distributed assets to assist in system balancing actions. After 8 months of successful trials, LCM is now live and operational.

On 16 January 2024, the LCM ESO team along with Piclo Energy hosted the Futures and Fairer Access webinar. This webinar and more information on the LCM can be found on our website.

The webinar follows project go-live in the Electricity National Control Centre (ENCC) on the 11 December 2023. The emphasis for this webinar was on updating LCM providers with progress - briefly introducing the LCM to new providers, together with a recap of what the service has achieved throughout its trial phase and the first month of live operational use in the ENCC.

The event also helped update our stakeholders on C16 consultations we have heard are important to them to be able to access LCM and ensure our markets are open and encouraging competition. The latter falls under the Futures and Fairer Access initiative within LCM to further increase volumes and manage providers' expectations regarding pricing. We encouraged feedback for the LCM into the informal and formal C16 consultations. We aim to continue to listen to our suppliers and aggregators as well as our wider stakeholders to ensure ESO remains open and transparent.

The webinar was well received by industry with around 80 total attendees. At the end of the webinar, we had a productive open Q&A session with industry. Going forward, the LCM team continues to welcome any feedback on the service, either through our C16 consultations or the Future of Balancing Services dot box for anything else (box.futureofbalancingservices@nationalgrideso.com).

Improving connection charge billing processes

On 4 January, we successfully released connection charging into the new settlements and revenue billing system (STAR). STAR is the strategic platform for the ESO's highly complex and unique billing and invoicing processes. It's progressively replacing two existing systems for electricity transmission charging (includes billing) and for payment of the balancing services (ancillary settlements business).

The ESO is responsible for recovering around £230m per year on behalf of the transmission operators. This latest release enables annual charge setting and billing to run from STAR from January 2024 onwards with greater efficiency, compliance, and improved customer experience. Improvements for the customer include a greater level of breakdown of their connection charges and allowing the invoice and billing information to be e-mailed to multiple people.

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 January 2024

Regional Development Programme (RDP)

The ESO has led on the development of an automated initiative to manage electricity supply and demand in the case of a system fault.

As part of the RDP initiative, the ESO, Scottish and Southern Electricity Networks (SSEN) and National Grid Electricity Distribution (NGED) on the South Coast have developed an automated scheme to manage small to medium-sized generators connected to a distribution network under certain transmission network conditions.

This solution is known as the N-3 intertripping scheme. Intertrip services are systems that automatically disconnect a generator or demand from the transmission system during a system fault. Under this new solution the same principle is extended to the distribution system to cover for an N-3 event.
An N-3 condition in the transmission system is defined as a planned single circuit outage followed by a fault outage on a double circuit.

The delivery of technical systems for the solution completed last year with support from the Digital, Data and Technology (DD&T) team. We completed all business change activities this month and enabled the complete go-live on 22 January.

The solution is yet another positive step in the direction of achieving a zero-carbon future. It will allow renewable distributed energy resources to ensure energy generation and continued operability of the network.

Operability Strategy Report webinar

On 23 January, we held our annual Operability Strategy Report webinar, following on from publication of the report. We presented the report's key messages to industry and held a question and answer session. We highlighted key achievements on our journey to meeting our zero carbon ambition for 2025 and our strategy to meeting the challenges we expect to face before a net zero electricity system in 2035. The webinar was well received, scoring 4 out of 5 for useful content and 90% of attendees learnt something new. The webinar recording, report and Q&A document are available on the website.