ESO RIIO2 Business Plan 1 (2021-23)

January 2023 Incentives Report

23 February 2023

ESO

Contents

Introduction

The ESO's RIIO-2 Business Plan, submitted to Ofgem in December 2019, sets out our proposed activities, deliverables, and investments for 2021-26 to enable the transition to a flexible, net zero carbon energy system.

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 1" period, which runs from 1 April 2021 to 31 March 2023.

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 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. 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.

Every six months, we produce a more detailed report covering all of the criteria used to assess our performance.

Please see our website for more information.

Summary of Notable Events

In January we have successfully delivered the following notable events and publications:

- We submitted our proposal for the Balancing Reserve service to Ofgem for approval. Balancing Reserve will reduce operational costs by moving reserve procurement from the BM to day ahead. A model has been created which predicts the impact and it forecasts a benefit over the next three years of between £100m and £1500m, with a central case of £900m.
- We achieved a low carbon day record on 7 January with a new zero carbon generation maximum of ~90%.Great Britain is one of the fastest decarbonising electricity systems in the world. As the system operator we have an ambition to be able to operate the network using 100% zero carbon electricity by 2025.
- On 10 January we saw a new daily wind generation record with wind generating over 21.6GW of energy, providing 53.7% of GB electricity. This broke the record set just 12 days previously.
- The first live activations of the Demand Flexibility Service, which took place on January 23 and 24, were a key milestone, demonstrating the potential for significant reductions in energy consumption. The results showed that participating consumers were able to reduce their consumption by over 662 MWh, which is a major achievement in a rapidly changing energy landscape.
- On 31 January, we published the first Balancing Services Use of System (BSUoS) fixed tariff which will be used to recover the costs of balancing the system for the 2023/24 charging year and beyond.
- Transmission Network Use of System (TNUoS) tariffs have been updated following the approval of CUSC modification CMP343 which changes the way the Transmission Demand Residual charge is collected from electricity network users.
- Energy Code Reform is looking to update how codes work across the industry to help drive towards Net Zero. Ofgem released a Call for Input regarding Energy Code Reform before Christmas and so we submitted a response outlining our views on Code Consolidation, Code Manager Licensing and Stakeholder Advisory Forums.
- Following the publication of our GB Connections Reform - Case for Change report, we've been hosting events with industry stakeholders, one on 10 January, to present how we believe GB Connections Reform should enable quicker connections and a more diverse range of connectees.
- We published our annual Operability Strategy report at the end of 2022. On 24 January, we held a very popular webinar to provide an overview of the report content but more importantly to take questions and feedback from industry.
- On 25 January we held our second Cost Benefit Analysis Methodology Consultation for Early Competition. Over the course of the workshops we provided an overview of the consultation, in addition to providing further detail on the methodology. Stakeholders provided valuable insight during the workshops and engaged in interesting discussions.

Table 1: Summary of Metrics and RREs

This table summarises our Metrics and Regularly Reported Evidence (RRE) performance for January 2023.

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£398m vs benchmark of £194m	●
Metric 1B	**Demand Forecasting**	Forecasting error of 2.2% vs benchmark of 2.0%	●
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 5.4% vs benchmark of 5.2%	●
Metric 1D	**Short Notice Changes to Planned Outages**	4.3 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**	90.6% of actions taken in merit order	N/A
RRE 1G	**Carbon intensity of ESO actions**	8.8gCO_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 40%	N/A

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

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

Gareth Davies
ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

January 2023 Performance

This metric measures our balancing costs based on a benchmark that has been calculated using the previous three years' costs and outturn wind generation. It assumes that the historical relationship between wind generation and constraint costs continues, recognising that there is a strong correlation between the two factors. Secondly, it assumes that non-constraint costs remain at a calculated historical baseline level. A more detailed explanation follows:

At the beginning of the year the non-adjusted balancing cost benchmark is calculated using the methodology outlined below. The final benchmark for each month is based on actual outturn wind, but an indicative view is provided in advance based on historic outturn wind.

i. Using a plot of the historic monthly constraints costs (£m) against historic monthly outturn wind (TWh) from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set to determine the monthly 'calculated benchmark constraints costs'.

ii. Using a plot of historic monthly total balancing costs (£m) against historic monthly constraint costs from the 36 months immediately preceding the assessment year, a best fit straight-line continuous relationship is set, with the intercept value of that straight line used to determine the monthly 'calculated benchmark non-constraints costs'.

iii. An equation for the straight-line relationship between outturn wind and total balancing costs is then formed using the outputs of point (i.) and point (ii.).

iv. The historic 3-year average outturn wind for each calendar month is used as the input to the equation in point (iii). The output is 12 ex-ante, monthly non-adjusted balancing cost benchmark values. The sum of these monthly values is the initial 'non-adjusted annual balancing cost benchmark'. The purpose of this initial benchmark is illustrative as it will be adjusted each month throughout the year.

Total Balancing Costs[1] ***(£m)*** = (Outturn Wind *(TWh)* x 25.254 *(£m/TWh)*) + 15.972 *(£m)* + 50.4 *(£m)*

A monthly ex-post adjustment of the balancing cost benchmark is made to account for the actual monthly outturn wind. This is done by following the process described in point (iv.) above but using the actual monthly outturn wind instead of the historic 3-year average outturn wind of the relevant calendar month. The annual balancing cost benchmark is then updated by replacing the historic value for the relevant month with this actual value.

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.

[1] This is the benchmark formula for 2022-23. The benchmark for 2021-22 was calculated as: (Outturn Wind (TWh) x 12.16 (£m/TWh)) + 19.75 (£m) + 41.32 (£m)

Figure 1: Monthly balancing cost outturn versus benchmark – two-year view

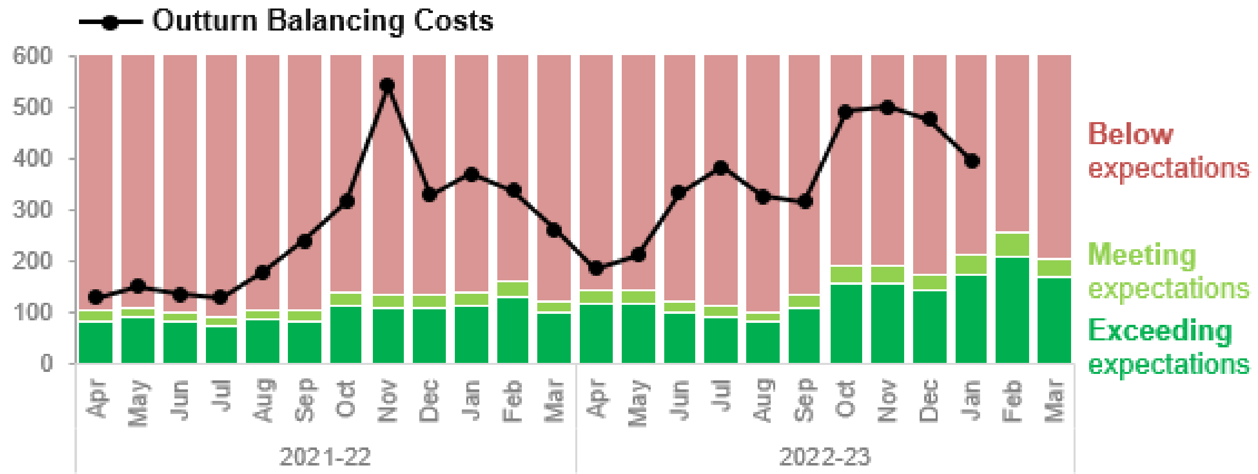


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	50	50	50	50			504
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	146	133	151	156			**1151**
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	196	183	201	206			**1654**
Outturn wind (TWh)	3.8	3.8	3.1	2.8	2.3	3.5	5.6	5.6	5.0	6.3			**41.7**
Ex-post benchmark: constraint costs (D)	80	80	62	52	42	73	125	125	110	143			**894**
Ex-post benchmark (A+D)	130	130	113	130	93	123	176	176	161	194			1398
Outturn balancing costs[2]	**188**	**213**	**335**	**385**	**327**	**318**	493	502	477	398			3635
Status	●	●	●	●	●	●	●	●	●	●			●

Rounding: monthly figures are rounded to the nearest whole number, with the exception of outturn wind which is rounded to one decimal place.

Performance benchmarks

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

[2] Please note that previous months' outturn balancing costs are updated every month with reconciled values

Supporting information

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.

January performance

The Balancing costs for January 2023 were £398m, which is a decrease of £79m from December 2022.
A new cost category, Winter Contingency, has been added to the non-constraint costs from October 2022. In response to the disruption of gas supplies to Europe, the Secretary of State approached the ESO to secure additional non-gas capacity over winter 2022/23. The ESO has contracted five generation units across three coal fired power stations to stay available across this winter to provide extra generation should it be needed to ensure electricity security of supply. These contracts began in October 2022 and are the main driver of the significant increase in non-constraint costs since September 2022.

Although the non-constraint volume of actions was lower than the previous month and the same period last year, the underlying non-constraints costs (excluding Winter Contingency) significantly decreased but remain higher than last year.
Constraint costs increased this month but remain lower than last year.
The total volume of actions was lower this month compared to January 2022, but the total cost was slightly higher compared to the corresponding period last year.

Breakdown of costs vs previous month

Balancing Costs variance (£m): January 2023 vs December 2022

		(a) Dec-22	(b) Jan-23	(b) - (a) Variance	decrease ◂▸ increase Variance chart
Non-Constraint Costs	Energy Imbalance	-11.0	-11.9	(0.9)	
	Operating Reserve	134.6	88.2	(46.4)	
	STOR	26.5	14.1	(12.5)	
	Negative Reserve	0.3	0.5	0.3	
	Fast Reserve	21.3	18.5	(2.8)	
	Response	14.9	20.2	5.3	
	Other Reserve	1.9	2.2	0.3	
	Reactive	36.5	32.6	(3.8)	
	Restoration	3.3	9.0	5.7	
	Winter Contingency	62.9	62.9	0.0	
	Minor Components	67.8	21.9	(45.9)	
Constraint Costs	Constraints - E&W	20.2	35.4	15.2	
	Constraints - Cheviot	3.1	2.3	(0.8)	
	Constraints - Scotland	1.9	13.8	11.9	
	Constraints - Ancillary	1.7	2.0	0.3	
	ROCOF	17.3	16.5	(0.7)	
	Constraints Sterilised HR	73.7	69.2	(4.5)	
Totals	Non-Constraint Costs - TOTAL	358.9	258.3	(100.7)	
	Constraint Costs - TOTAL	117.9	139.2	21.3	
	Total Balancing Costs	**476.9**	**397.5**	**(79.4)**	

As shown in the total rows from the table above, the non-constraint costs decreased by £101m this month.

Constraint spends increased by £21m.

Constraints in England & Wales and in Scotland were the main drivers behind this rise. All the other constraint categories fell this month or showed little variance from the previous month.

Within the Non-Constraint costs only Response and Restoration categories have shown an increase, while all other categories experienced a decrease in cost or showed little variance from the previous month.

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

- **Constraint-E&W: £15m increase,** due to a higher volume of BM actions required to reduce generation to manage thermal constraints.
- **Constraint-Scotland: £12m increase,** also due to a higher volume of BM actions required to reduce generation to manage thermal constraints.

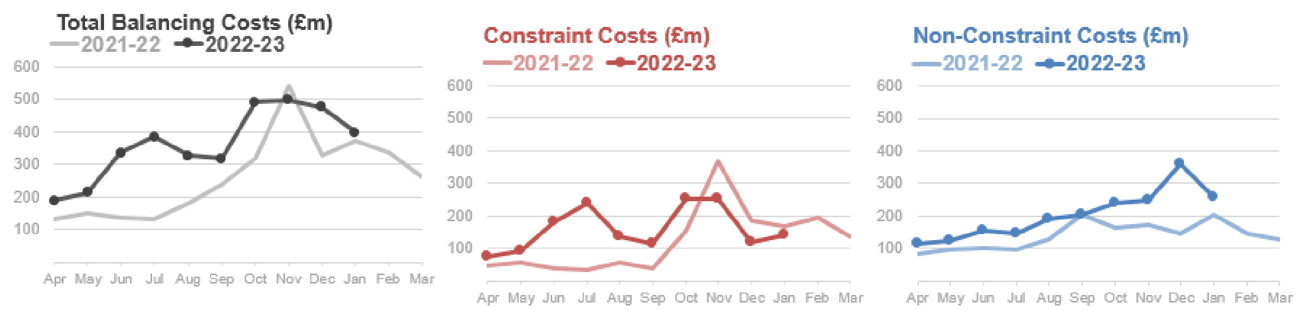
Non-constraint costs: The main drivers of the biggest variances this month are detailed below:

- **Operating Reserve: £46m decrease**. Healthy margins and a significant drop in the wholesale prices were the drivers, behind this significant reduction in cost.
- **Minor Components: £46m decrease.** We do not cover the variation in Minor Components here as it is driven by the data issue referenced earlier.

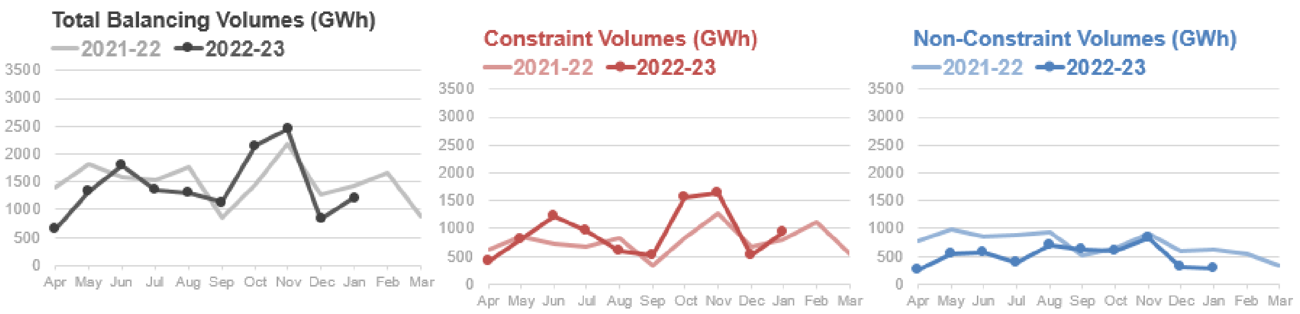
Constraint vs non-constraint costs and volumes

Restoration: Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included. To enable a direct comparison, in the graphs below these restoration costs are included for both 2020-21 and 2021-22.

Balancing COSTS (£m) monthly vs previous year



Balancing VOLUMES (GWh) monthly vs previous year



Please note that a portion of the **Minor Components** spend contributing to non-constraint cost and volume is 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.

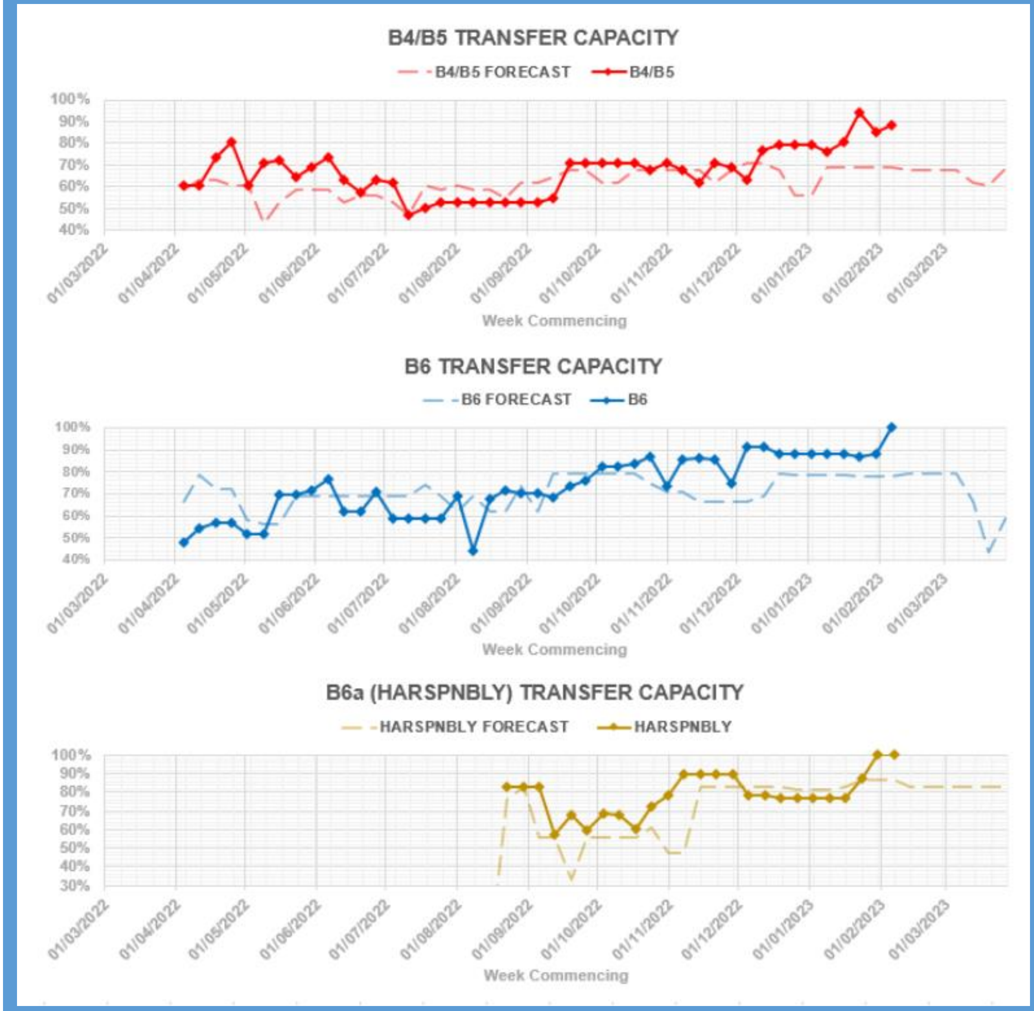
Constraint costs

Compared with the same month of the previous year:	• Constraint costs were £30m lower than in January 2022 due lower wholesale prices compared with last year
Compared with last month:	• Constraint costs showed an increase of £21m from December 2022 due to significantly higher volume of actions

Non-constraint costs

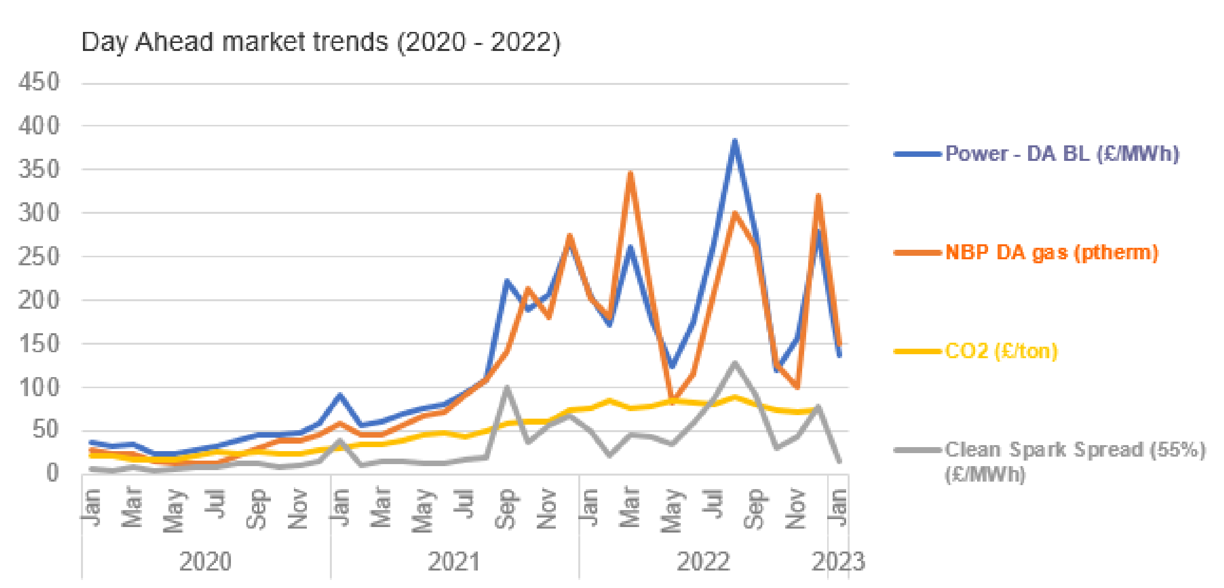
Compared with the same month of the previous year:	• Non-Constraint costs were around £55m higher than in January 2022 due to the winter contingency costs of £63m.
Compared with last month:	• Non-Constraint costs were over £100m lower than in December 2022 mainly due to a decrease in the Operating Reserve and in the costs allocated to the Minor Components category.

Network availability 2022-33



Please note that transfer capacity is discussed in more detail at each week's Operational Transparency Forum. Details of how to sign up, and recordings of previous meetings are available here.

Changes in energy balancing costs

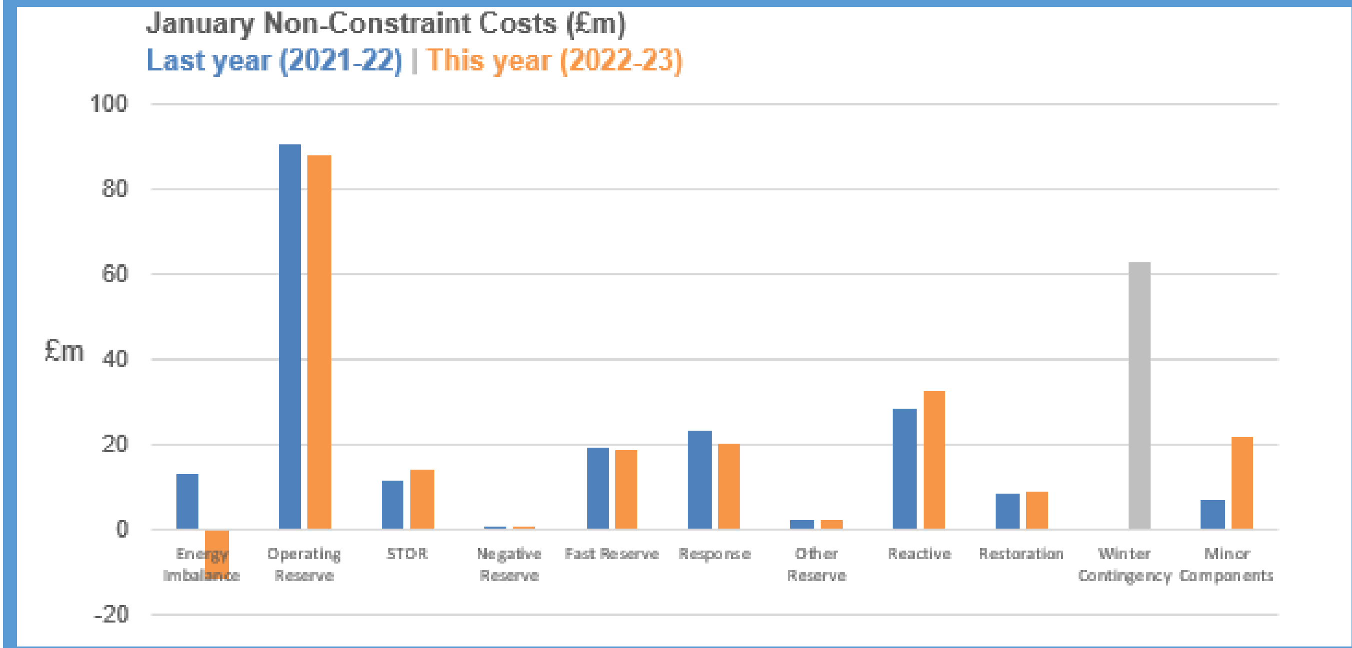


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices, day ahead Gas prices and Clean Spark Spread prices have decreased in January 2023 and remain lower compared to previous year.

Carbon prices were not available this month.

Cost trends vs seasonal norms

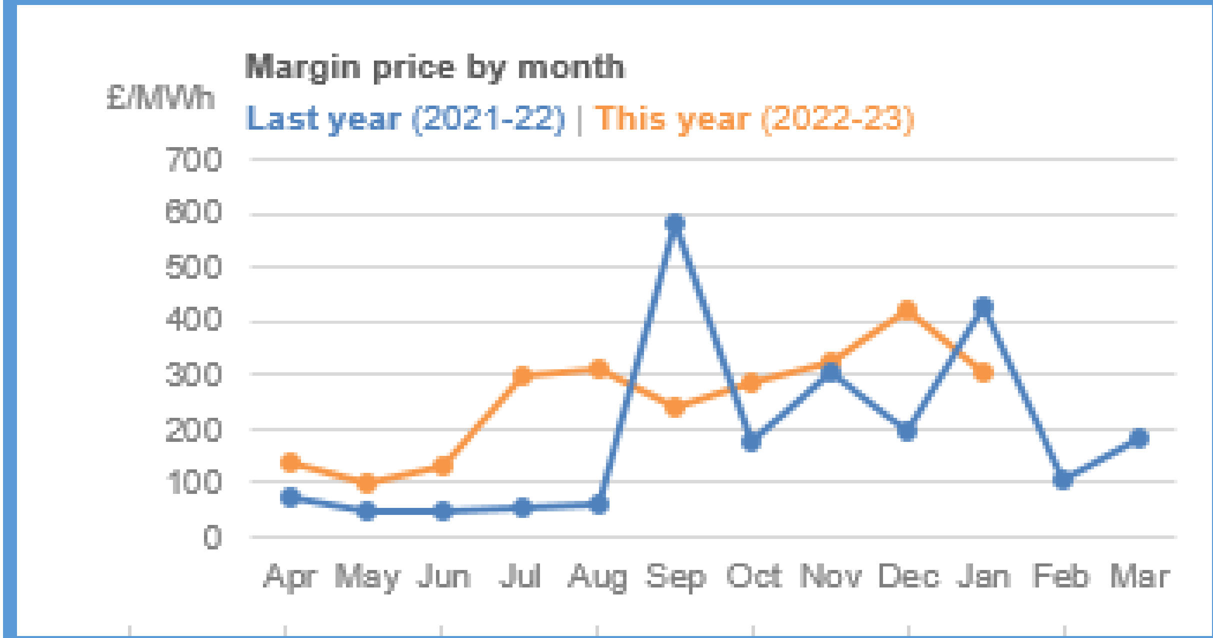


Comparing the non-constraint costs of January 2023 with those of January 2022, we can see that apart from STOR, Reactive and Minor Components which showed a non-significant increase, all the other categories showed a decrease in cost or a small deviation from the previous month.

Winter Contingency costs were introduced this year.

- STOR increased by £3m, as cleared costs of procuring the service have increased
- Reactive costs are £4m higher. Volumes from the relevant ancillary services are not available at the time of writing this report
- Winter Contingency: £63m higher. Due to the winter contingency contracts that started on October 2022. See introduction to this section for more detail.
- Minor components: £15m increase. We have identified most of the cost in this category should have been allocated to the Operating reserve category. It will be corrected once the data issue is resolved.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have decreased since December and are lower than the same month last year.

Daily costs trends

As discussed above, January balancing costs were £79m lower than the previous month.

However, we counted two days that recorded a spend of more than £20m.

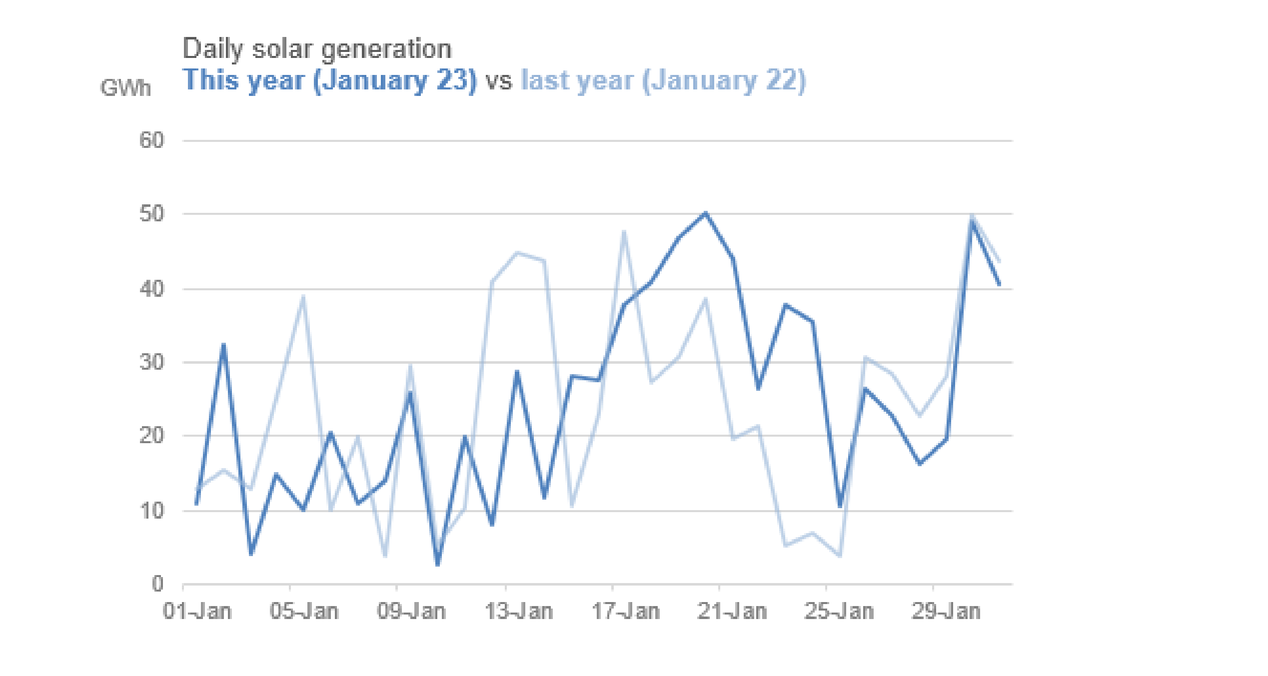
On Wednesday 25 January when out-turned costs exceeded £22m, the major cost component was the Constraint E&W and on Tuesday 31 January the major cost component was Constraint Scotland.

The average daily cost of the month was £12.8m, a £2.6m decrease from the previous month.
The main driver behind the high-cost days of the month, was the higher volume of BM actions taken to reduce generation to manage thermal constraints* and to support voltage control and the system stability.

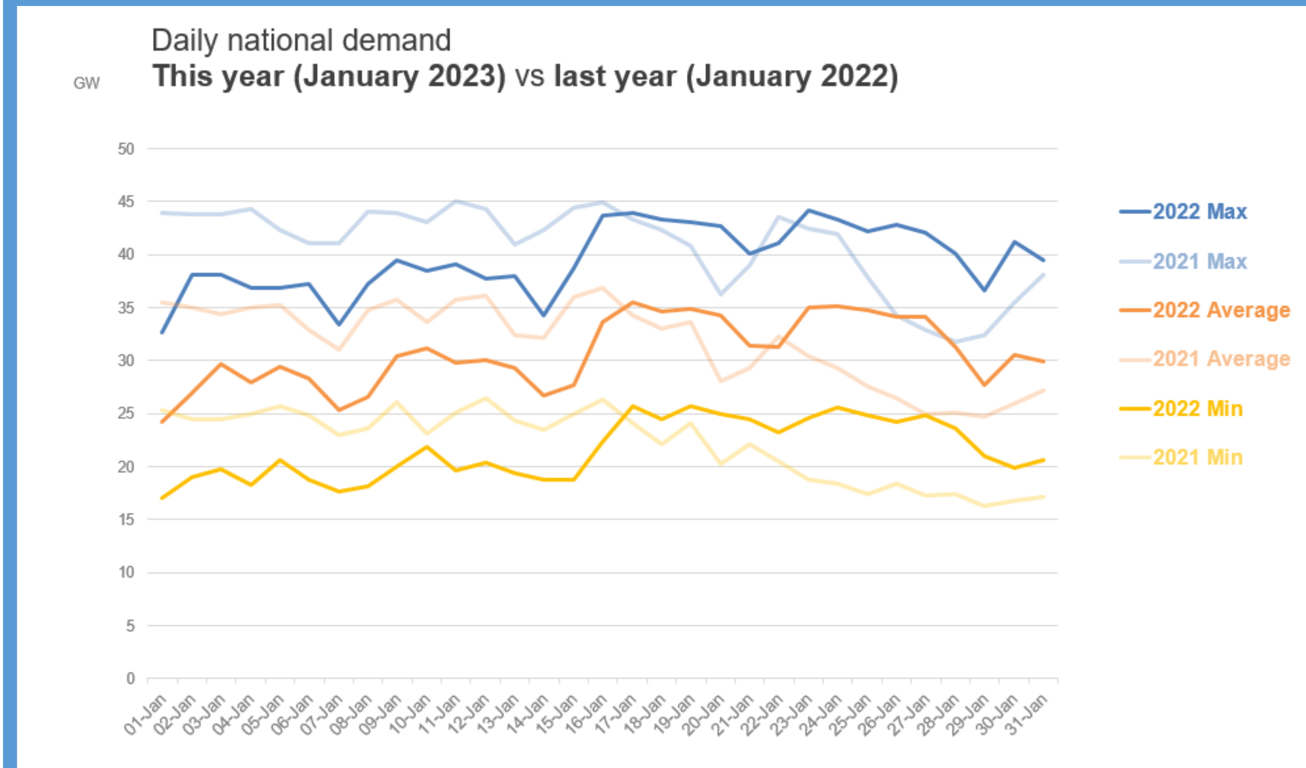
*When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance.

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 actions

Solar generation - January 2023 vs January 2022



Outturn Demand – January 2023 vs January 2022



Metric 1B Demand forecasting accuracy

January 2023 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast demand and outturn demand for each half hour period. The benchmarks are drawn from analysis of historical forecasting errors for the five years preceding the performance year.

If the Optional Downward Flexibility Management (ODFM) service is used, it will be accounted for in the data used to calculate performance. The ESO will publish the volume of instructed ODFM.

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.

Performance will be assessed against the annual benchmark of 2.1%, but monthly benchmarks are also provided as a guide. The ESO will report against these each month to provide transparency of its performance during the year.

Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark – two-year view

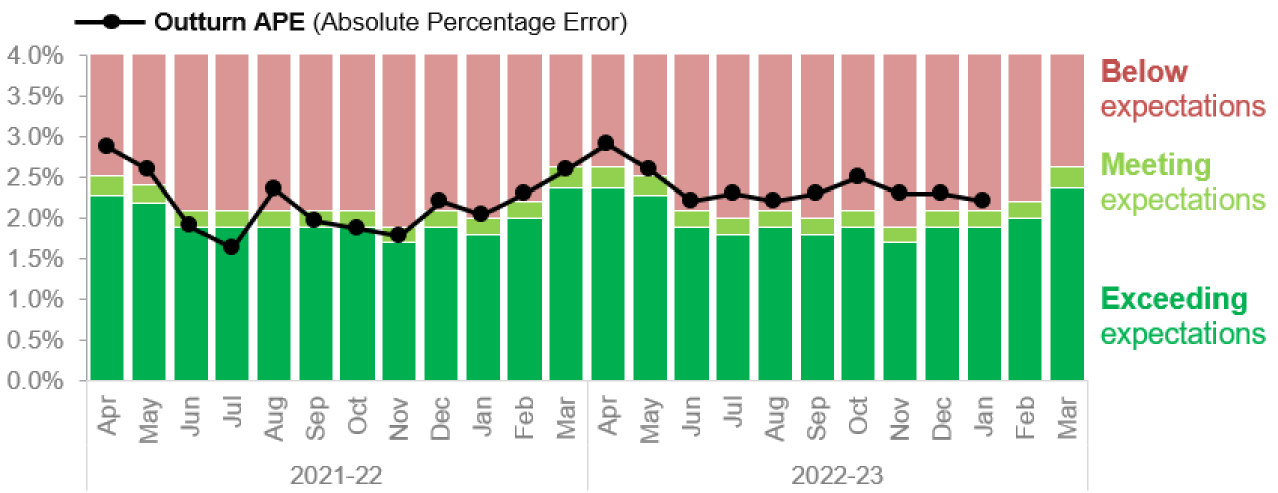


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
Indicative benchmark (%)	2.5	2.4	2.0	1.9	2.0	1.9	2.0	1.8	2.0	2.0	2.1	2.5	**2.1**
APE (%)	2.9	2.6	2.2	2.3	2.2	2.3	2.5	2.3	2.3	2.2			
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

For January 2023, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.16% compared to the indicative performance target of 2.05%, and therefore below expectations.

Measured on a MW scale however, January had an average error of 642MW, which is an improvement on the 5-year average of 725MW. National demand has continued to fall year on year. This is largely due to the continuing increase in embedded generation, which increases uncertainty and errors but decreases the 'National demand' denominator used to calculate MAPE. This has the effect of increasing the percentage errors, even if those errors have improved on a MW scale.

January had strong winds for the first half of the month, dropping for the middle section, then raising again for the final three days. In addition to this, it was a particularly sunny January – the third sunniest on record according to the MET office. These weather effects contribute to both large renewable generation (with increased uncertainty) and lower National Demand (due to embedded generation). Additionally, human behaviour factors make the New Year period particularly uncertain, contributing to the two highest error days this month (1 and 2 Jan).

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	320	22%
1500 MW	101	7%
2000 MW	40	3%
2500 MW	16	1%
3000 MW	3	0%

The days with largest MAPE were January 1, 2 and 19.

DFS tests were run on January 17, 19, 30, 31 and DFS live events occurred on 23, 24 January. These events add additional uncertainty versus regular days, and against the five year benchmark period before DFS was introduced.

Work is under way implementing the recently increased amount of weather data we receive and feed into our forecast models. Model improvements are currently being developed, though this will take time to collect enough data to robustly measure the impact of these forecast improvements (at least one full quarter), and accuracy improvements won't be seen immediately.

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. See our website for more detail on triads.

In January we saw 9 days affected by triad avoidance behaviour, totalling approximately 16,000 MW. These have the effect of increasing uncertainty when forecasting peak demands.

Metric 1C Wind forecasting accuracy

January 2023 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. 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.

Figure 3: BMU Wind Generation Forecast APE vs Indicative Benchmark – two-year view

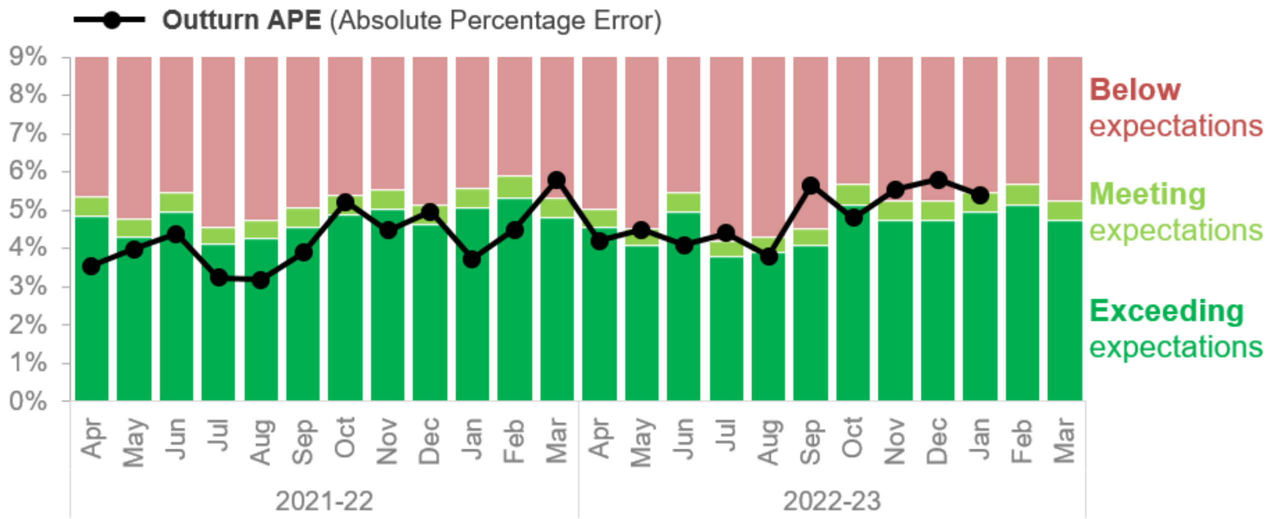


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	Full Year
BMU Wind Generation Forecast Benchmark (%)	4.8	4.3	5.2	4.0	4.1	4.3	5.4	5.0	5.0	5.2	5.4	5.0	**4.8**
APE (%)	4.2	4.5	4.1	4.4	3.8	5.7	4.8	5.5	5.8	5.4			
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

For January the wind power forecast accuracy achieved was 5.4% against a target of 5.2%, which falls within the ‘meeting expectations’ margin.

The first half of January 2023 saw high winds over much of the UK, with calmer conditions prevailing in the second half of January. On average, wind speeds in January were similar to the long-term average for January.

The January wind forecasts underpredicted the metered generation on some days and overpredicted on others. The largest errors were seen on 18–19 January, where the forecast error reached over 4 GW in magnitude. These errors were associated with small-scale but intense storms from the North (“polar vortices”) passing to the East of the UK. Despite the advances in weather forecasting over recent decades, such events remain difficult to forecast at the day-ahead stage. Small errors in the timing or intensity of such storms can lead to large wind power forecast errors.

The Energy Forecasting team at the ESO began receiving additional weather data from the Met Office on 24th November, more than doubling the number of forecast locations for which we receive weather forecasts. This new data is now being used to recalibrate the wind power forecast models. This should lead to a small improvement in wind forecasts from around April 2023. In addition, the Energy Forecasting team at the ESO will be improving our wind power forecasting software infrastructure over the coming months to enable the development of more advanced models.

Metric 1D Short Notice Changes to Planned Outages

January 2023 Performance

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

Figure 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages – two-year view

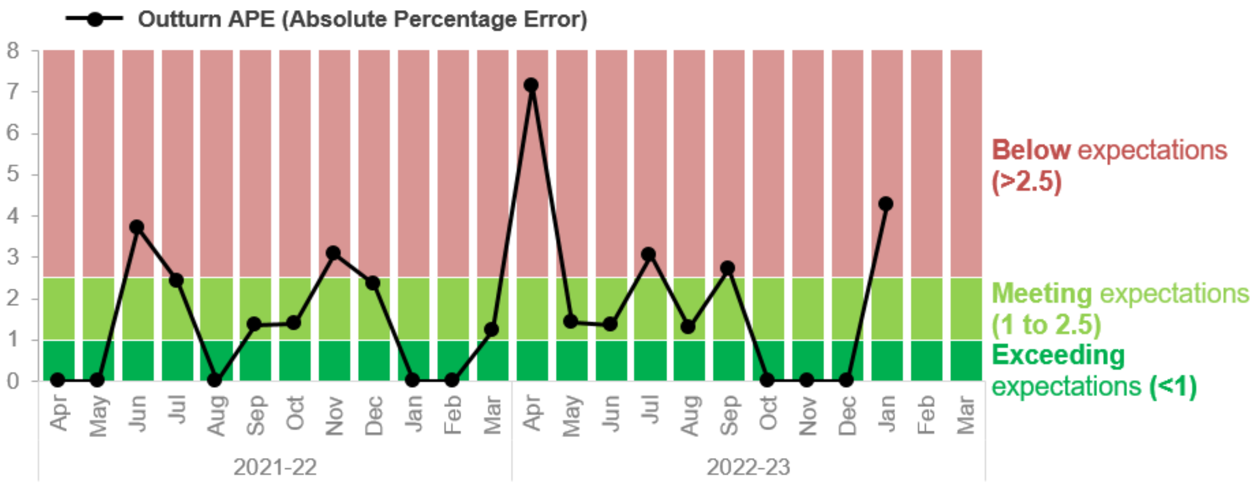


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766	739	684	635	441	467			6531
Outages delayed/cancelled	5	1	1	2	1	2	0	0	0	2			14
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3.0	1.3	2.7	0	0	0	4.3			2.1
Status	●	●	●	●	●	●	●	●	●	●			●

Performance benchmarks

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

Supporting information

In January, the ESO has successfully released 467 outages with two delays or cancellations occurring due to ESO process failures. The number of stoppages or delays per 1000 outages was 4.28, which is outside of the 'Meeting Expectations' target of less than 2.5 delays or cancellations per 1000 outages. However, the cumulative yearly number of stoppages or delays per 1000 outages still remains within the 'Meeting Expectations' target at 2.14. The events can be summarized below:

The first delay occurred due to an outage on a Super Grid Transformer (SGT) that required the substation to be re-configured to re-balance the power flows. This requirement was not identified in planning timescales. Without this reconfiguration, for a certain securable fault there would be an abnormal power flows through the Distribution Network Owners (DNO) network. The site also feeds power supplies to a power station. The control room identified this overnight before the outage was due to proceed and proposed a different substation configuration to mitigate the risk. The DNO had agreed to this original running arrangement in planning timescales but did not appear to be aware of this risk. The outage was delayed by several hours as agreement for the new configuration was then required by the DNO planners. An Operational Learning Note (OLN) has been written highlighting the considerations for substation re-configuration to prevent the abnormal flows post-fault.

The second delay was due to an 275kV circuit outage and required the substation to be re-configured to re-balance the power flows across the site. There is a requirement to inform the DNO of the potential for fault level issues within their local network. During planning timescales, and due to a human error, the DNO were not notified. In preparation for a Monday start, the control room noted the DNO were not aware. A new assessment was required in order for the DNO Outage Planners to review and accept the configuration. The DNO planners were not available until normal Monday office hours. Consequently, the outage was delayed by several hours. An Operational Learning Note (OLN) has been written capturing some preventative actions to assist in notifying the DNO when the 275kV site is to be re-configured and to better understand the DNOs fault level constraint.

RRE 1E Transparency of operational decision making

January 2023 Performance

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

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

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

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

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

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

The Dispatch Transparency dataset, first published at the end of March 2021, has already sparked many conversations amongst market participants. It is anticipated that as we continue to publish this dataset, we will be able to provide additional insight into the actions taken in the Balancing Mechanism and help build trust as we become more transparent with our decision making.

Figure 5: Percentage of balancing actions taken in merit order in the BM – two-year view

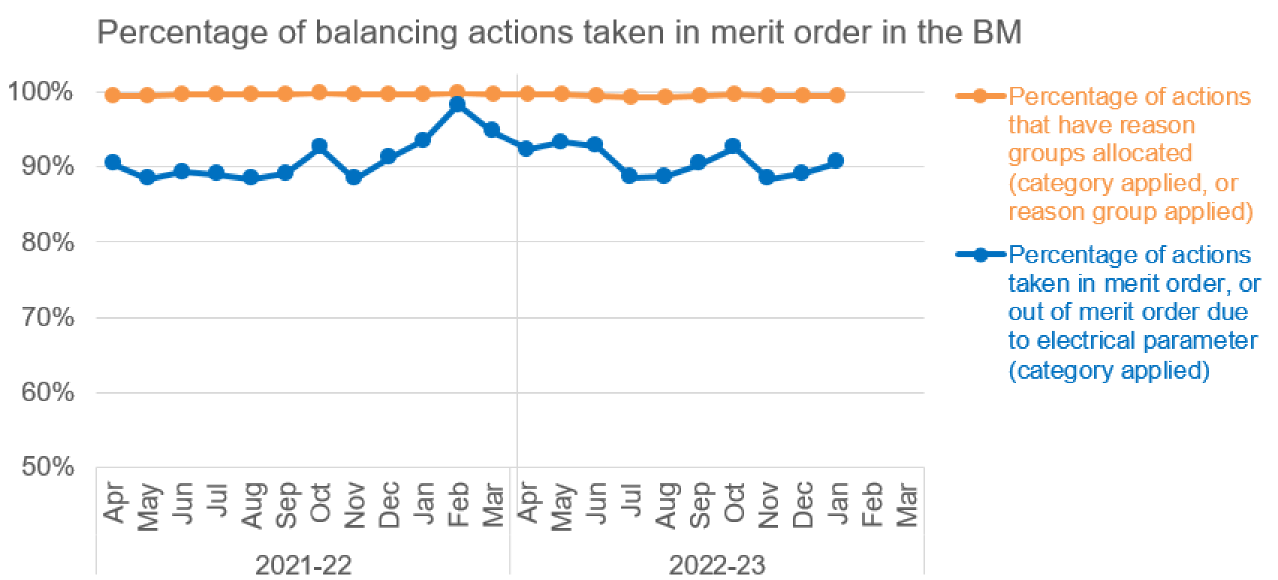


Table 6: Percentage of balancing actions taken outside of merit order in the BM

	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)	92.3%	93.3%	92.8%	88.6%	88.7%	90.4%	92.6%	88.4%	89.1%	90.6%		
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%	99.4%	99.6%	99.7%	99.6%	99.6%	99.6%		
Percentage of actions with no category applied or reason group identified	0.3%	0.3%	0.4%	0.6%	0.6%	0.4%	0.3%	0.4%	0.4%	0.4%		

Supporting information

This month 90.6% of actions were 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 January 2023, we sent 53,944 BOAs (Bid Offer Acceptances) and of these, only 227 remain with no category or reason group identified, which is 0.4% of the total.

Data issue: As mentioned in our October report, we recently identified an issue with the data used to support this metric. The impact of this issue is minor and is very unlikely to affect the reported figures.

- Over the 19-month period from April 2021, 11 days were not captured by the dataset.
- We have identified the cause in the data which is provided by an ESO legacy tool and we have implemented countermeasures to ensure any future missing days are flagged promptly and included into the dataset.
- We are unable to recreate the previous missing days due to the time elapsed.

RRE 1G Carbon intensity of ESO actions

January 2023 Performance

This 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.

Figure 6: Average monthly gCO2/kWh of actions taken by the ESO - two-year view

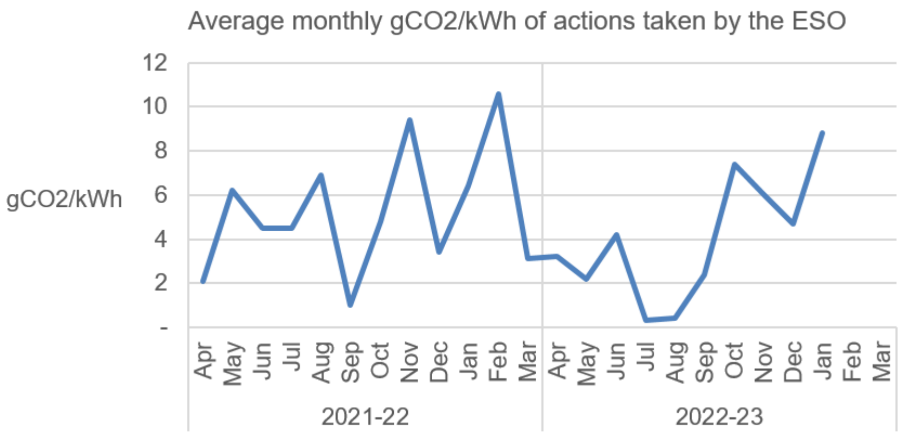


Table 7: Average monthly gCO2/kWh of actions taken by the ESO

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Carbon intensity (gCO2/kWh)	3.2	2.2	4.2	0.3	0.4	2.4	7.4	6.0	4.7	8.8		

Supporting information

In January, the average carbon intensity of balancing actions was 8.8 gCO2/kWh. This was an increase from December but is relatively normal for this time of year as temperatures drop and the demand rises. In addition, wind levels have meant that we have had to constrain off wind generation due to thermal export constraints and replace the missing energy with carbon generation. This increases the carbon intensity of our actions.

For Q1, Q2 and Q3, the average carbon intensity was 3.2 gCO2/kWh, 1.0 gCO2/kWh and 6.1gCO2/kWh respectively. Q2 saw a reduction in the carbon intensity as we were taking significantly fewer operational actions compared with previous months. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This reduces ESO interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly.

In January, the largest decrease in carbon intensity due to ESO's actions was at 00:00 on 29th January with a minimum intensity of ESO actions at –41.2 gCO2/kWh. This was the biggest reduction this financial year.

RRE 1I Security of Supply

January 2023 Performance

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 ± 0.3Hz 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.

Table 8: Frequency and voltage excursions (2022-23)

	2022-23											
	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	1	1	1	1	0	0	0	0	0	0		
Voltage Excursions defined as per Transmission Performance Report[3]	0	0	0	0	0	0	0	0	0	0		

Supporting information

There were no reportable voltage or frequency excursions in January.

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

RRE 1J CNI Outages

January 2023 Performance

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.

Table 9: Unplanned CNI System Outages (Number and length of each outage) – two-year view

Unplanned	2021-22	2022-23											
	TOTAL	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	0		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0		

Table 10: Planned CNI System Outages (Number and length of each outage) – two-year view

Planned	2021-22	2022-23											
	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	3[4] outages	0	0	0	1 outage 186 minutes	0	0	0	1 outage 165 minutes	0	0		
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0	0	0	0		

Supporting information

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

[4] July 2021: 1 outage, 216 minutes.
November 2021, 1 outage, 215 minutes.
March 2022, 1 outage, 196 minutes.

Notable events during January 2023

Balancing Reserve proposal submitted to Ofgem

In January we submitted our proposal for the Balancing Reserve service to Ofgem for approval. Balancing Reserve will reduce operational costs by moving reserve procurement from the Balancing Mechanism (BM) to day ahead. This will reduce our reliance on a few marginal generators and increase competition in the BM. It is forecast to reduce consumer costs significantly. We asked consultants Lane Clark and Peacock to model the impact and they forecast a benefit over the next three years of between £100m and £1500m, with a central case of £900m.

To enable these significant consumer savings, we have designed the service so that we can implement it quickly, to maximise consumer savings. Going forward, we are developing the service further to improve the product and widen participation. However if we delayed implementation until 2024 when these improvements are ready, we will miss out on substantial consumer savings. Therefore bringing it forward saves more than £200m, but means that we have had to make compromises on unit size so we can progress as fast as possible.

This was a tricky development that we pushed forward at pace. We started in October last year and are currently on target to go live in March.

Low Carbon day record - 7th January

Great Britain is one of the fastest decarbonising electricity systems in the world. As the system operator we have an ambition to be able to operate the network using 100% zero carbon electricity by 2025.

We assess progress against our ambition by measuring the proportion of zero carbon transmission connected generation that the system can accommodate before and after our actions. Zero carbon generation includes hydropower, nuclear, solar, wind and pumped storage technologies. We share progress through the Zero Carbon Operability (ZCO) indicator. This is reported in our Operability Strategy Report and in our ESO RIIO2 Business plan quarterly incentives reports.

Our ability to operate a zero carbon network is increasing as we are pushing forward innovative, world first approaches to transform how the power system operates.

We had a new zero carbon generation maximum of ~90% on 7 January 2023. During this new maximum, we needed to synchronise six additional carbon units for system reasons (voltage and minimum inertia). However the need for these carbon units will be removed for settlement periods such as these, through our on-going voltage and stability work. This means that by 2025 we will have the ability to operate a zero carbon network, reducing our reliance on carbon generation for ancillary services and also reducing operational costs.

New Daily Wind record – 10th January

On 10 January we saw a new daily wind generation record with wind generating over 21.6GW of energy, providing 53.7% of GB electricity. This broke the record set just 12 days previously.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

January 2023 Performance

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.

Figure 7: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

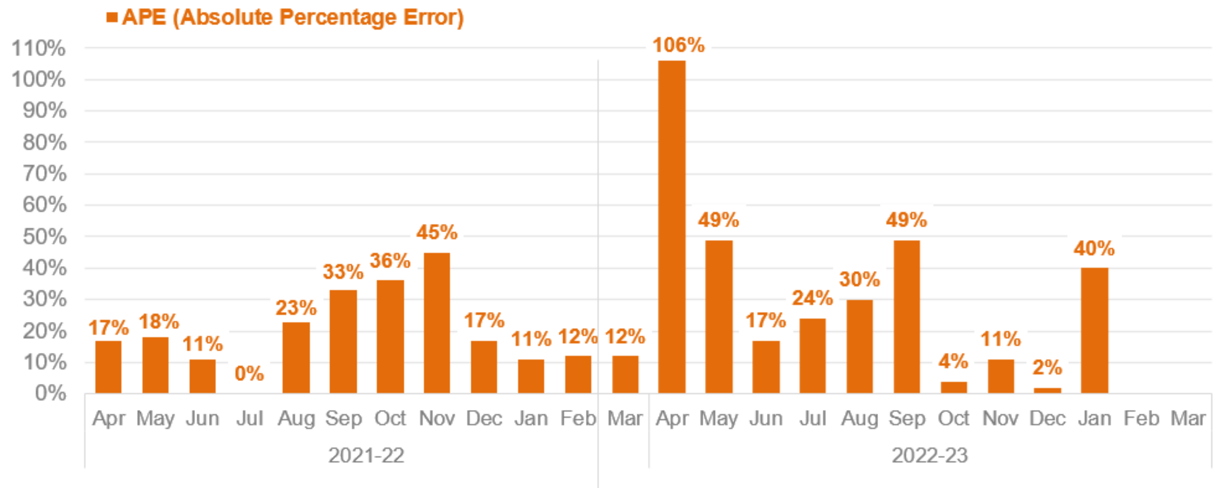


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[5] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.0	9.4	10.3	9.2	8.5	12.5	11.7	10.5	8.9		
Month-ahead forecast	11.0	9.0	7.7	7.8	11.9	12.7	12.1	13.0	10.3	12.4		
APE (Absolute Percentage Error)[6]	**106%**	**49%**	**17%**	**24%**	**30%**	**49%**	**4%**	**11%**	**2%**	**40%**		

Supporting information

The BSUoS charge (£/MWh) depends on the total BSUoS cost and the total volume. The BSUoS cost forecast 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 we expect the actual BSUoS charge to be lower than the forecast provided the actual volume is at or above the estimate (and vice versa).

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

January performance

Absolute Percentage Error (APE) increased from 2% in December 2022 to 40% in January 2023. The main driver of the variance was the outturn costs being significantly lower than expected, partly offset by the outturn volumes being slightly higher than expected.

Costs:

January outturn costs were below the 5th percentile of the forecast produced at the beginning of December. This was mainly due to the wholesale electricity prices being 74% lower in outturn (£133/MWh) than the forward market prices available at the beginning of December (£518/MWh).

Forecast for January BSUoS costs (made at the start of December): **£485 million** (Not including winter contingency costs)
Outturn costs for January: **£398 million** (£335m plus winter contingency cost £63m)

Volumes:

Estimated BSUoS Volume (made at the start of December): **47.2 TWh.**
January actual BSUoS volume: **48.8 TWh** (3.4% higher than the estimate)

Notable events during January 2023

First live activations of Demand Flexibility Service

Demand flexibility is a rapidly growing field that aims to use technology to manage and balance energy demand on the power grid. The Demand Flexibility Service (DFS) has been developed to allow the ESO to access additional flexibility when the national demand is at its highest, typically, during winter evenings, which was not previously accessible to the ESO in real-time.

The first live activations of DFS, which took place on January 23 and 24, was a key milestone, demonstrating the potential for significant reductions in energy consumption. The results showed that participating consumers were able to reduce their consumption by over 662 MWh, which is a major achievement in a rapidly changing energy landscape. This reduction in energy consumption not only has a positive impact on the environment, but also decreases costs for consumers and utilities who participate in the service. It also helps to maintain a stable and reliable energy supply for everybody.

Publication of first BSUoS Fixed Tariff

On 31 January, we published the first Balancing Services Use of System (BSUoS) fixed tariff which will be used to recover the costs of balancing the system for the 2023/24 charging year and beyond.

Since the BSUoS charge was first introduced in 2001 it has been charged on an ex-post basis, the costs to balance the system each day were what parties paid as BSUoS charges and those costs were only known after the day had occurred. In recent years the costs of balancing the system have become more volatile and trying to predict these daily costs was a major challenge for parties that pay the BSUoS charge.

With the introduction of an ex-ante fixed tariff the price per MWh is set as a tariff ahead of the settlement day and parties are able to use this to predict their own costs far more accurately. This change is predicted to lead to cost savings for the end consumer as industry parties no longer have to factor in the same risk premia as they did previously.

The fixed tariff for BSUoS represents the most fundamental change to the methodology ever made and in the build up to producing our first fixed tariff we have held several industry consultations via webinars and published a draft BSUoS tariff to seek further industry feedback. The industry feedback has helped shape our forecasting model for balancing costs and we will continue to consult with industry as the fixed tariff methodology is implemented and further refined.

Implementation of TNUoS following TCR recommendation

Transmission Network Use of System (TNUoS) tariffs have been updated following the approval of CMP343 which changes the way the Transmission Demand Residual charge is collected from electricity network users, replacing the existing half-hourly triad residual component and the current Non half-hourly unit charges.

The previous methodology incentivised inefficient actions and had different treatments for transmission and distribution. This change came about following Ofgem’s Targeted Charging Review (TCR) and implements a methodology whereby those who are liable for the Transmission Demand Residual (TDR) are placed in bands and attributed proportion of the cost. This has been incorporated into the Final Tariffs that have been published in January 2023 and will go live from April 2023.

Energy Code Reform call for Input

Energy Code Reform is looking to update how the codes work across the industry to help drive towards Net Zero. Ofgem released a Call for Input regarding Energy Code Reform before Christmas and so we submitted a response on 1 February outlining our views on Code Consolidation, Code Manager Licensing and Stakeholder Advisory Forums.

We noted that the Energy Code Reform aligns with the strategic goals of a Future System Operator (FSO) of independence, expertise, and a greater ability to set future strategy and advice. The current timescales mean the FSO transition will occur before Energy Code Reform and we support this approach as we believe this will reduce complexity and allow Energy Code Reform to be implemented with more operational clarity.

Overall, we are supportive of the approaches suggested by Ofgem and share the sense of urgency that Net Zero places on us collectively as an industry. We believe that further detail is required for developing details on the Code Manager role and how that will work. We will continue to develop our thinking on this whilst Ofgem contemplates responses from across industry.

https://www.nationalgrideso.com/industry-information/codes/energy-codes-review

Role 3 System insight, planning and network development

Please note there are no metrics for Role 3

GB Connections Reform – Case for Change event on 10th January

Following the publication of our GB Connections Reform - Case for Change report, we've been hosting events with industry stakeholders to present how we believe GB Connections Reform should enable quicker connections and a more diverse range of connectees. This will help deliver Net Zero and security of supply at the best cost to consumers.

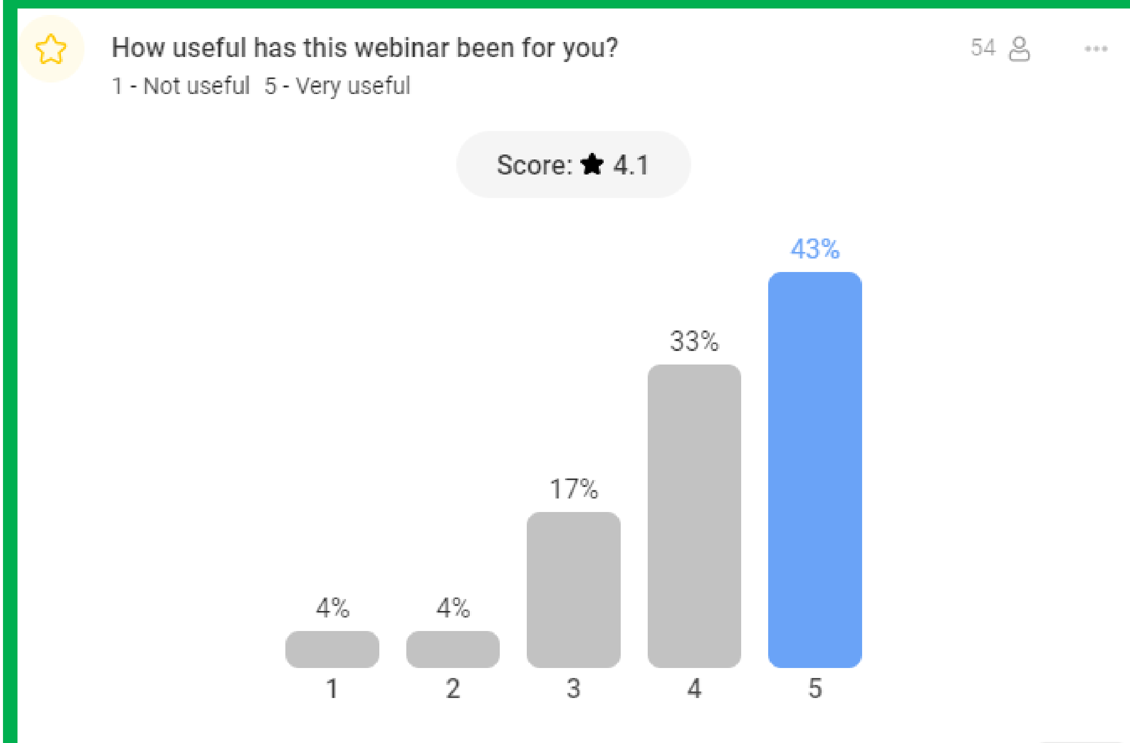
One of these events was held on 10 January, the attendance was good at just over 90 people and we obtained great engagement and feedback during the session.

2023 Operability Strategy Report webinar on 24th January

We published our annual Operability Strategy report at the end of 2022.

On 24 January 2023, we held a webinar to provide an overview of the report content but more importantly to take questions and feedback from industry. The webinar was extremely popular, with over 160 participants joining the call. We also received some great feedback scores with an average of 4.1 (out of 5). Engagement was high throughout the webinar and we had some great questions. The recording and Q&A can be found on our website here.

We will be planning some future deep dives sessions in 2023 to provide some more in depth discussions on the topics raised within the report.



Cost Benefit Analysis consultation workshop 25th January

On 25 January we held our second Cost Benefit Analysis Methodology Consultation for Early Competition. Over the course of the workshops we provided an overview of the consultation, in addition to providing further detail on the methodology. Stakeholders provided valuable insight during the workshops and engaged in interesting discussions.

We published our CBA Consultation at the end of last year. The purpose of the CBA Methodology is to assess the cost to consumers of delivering a particular onshore network project through the commercial model set out in the Early Competition Plan (ECP), versus a regulatory framework if undertaken by an incumbent Transmission Owner. The consultation and feedback from stakeholders will play a key role in helping us refine our thinking and direct subsequent work to finalise our proposal.