# ESO RIIO2 Business Plan

## Quarterly Incentives Report (October – December 2021)

26 January 2022

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# 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

In Q3 we have successfully delivered the following notable events and publications:

- In October 2021 we went live with an inertia measurement and forecasting service tool, in collaboration with GE Digital.
- In October 2021 Reactive Technologies announced the launch of its flagship grid stability measurement service that was developed with the support of the ESO.
- Virtual Energy System launched at COP26
- Scope set out in December 2021 for the review of the balancing market
- Grid Code modification GC0137, Minimum specification for equipment providing grid-forming capability, was approved to go to Ofgem for a decision in October
- The Autumn Markets Forum was held on 18 November 2021 and an update on Net Zero Market Reform was published on the same day.
- Code Administrator workshop was held on 6 December 2021
- Dynamic Regulation and Dynamic Moderation consultation closed on 15 December 2021
- The Contracts for Difference (CfD) fourth and biggest round opened on 13 December 2021
- On 20 December we published three reports on Distributed Restart
- An early consultation for C16 changes was shared in November 2021.
- In October 2021 work began on our third Bridging the Gap to Net Zero report.
- We released our Autumn Offshore Coordination progress publication in October 2021.
- We launched the Stability Pathfinder Phase 2 commercial tender in November 2021.

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) performance for Q3 2021-22.

**Table 1: Summary of Metrics**

Monthly (M) and Quarterly (Q) Metrics

| Metric | | Performance<br>December figure for monthly Metrics & RREs, Q3 figure for quarterly Metrics & RREs) | M / Q | Status<br>Oct | <br>Nov | <br>Dec | <br>Q3 |
|---|---|---|---|---|---|---|---|
| Metric 1A | **Balancing Costs** | In December, £327m vs benchmark of £123m | M | ● | ● | ● | ● |
| Metric 1B | **Demand Forecasting** | December forecasting error of 2.2% (vs benchmark of 2.0%) | M | ● | ● | ● | ● |
| Metric 1C | **Wind Generation Forecasting** | December forecasting error of 5.0% (vs benchmark of 4.9%) | M | ● | ● | ● | ● |
| Metric 1D | **Short Notice Changes to Planned Outages** | In December, 2.4 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5). | M | ● | ● | ● | ● |
| Metric 2A | **Competitive procurement** | In Q3, 46% of services procured by competitive means (vs Year 1 benchmark of 50-60%) | Q | n/a | n/a | n/a | ● |

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

**Table 2: Summary of RREs**

| RRE | | Performance<br>December figure for monthly Metrics & RREs, Q3 figure for quarterly Metrics & RREs) | M / Q |
|---|---|---|---|
| **RRE 1E** | **Transparency of Operational Decision Making** | In December, 99.8% of actions have reason groups allocated | M |
| **RRE 1F** | **Zero Carbon Operability indicator** | In Q3, the system accommodated a maximum 84.3% zero carbon transmission connected generation | Q |
| **RRE 1G** | **Carbon intensity of ESO actions** | In December 3.4gCO2/kWh of actions taken by the ESO | M |
| **RRE 1H** | **Constraints cost savings from collaboration with TOs** | In Q3, £507m avoided costs | Q |
| **RRE 1I** | **Security of Supply** | In December, 0 instances where frequency was more than ±0.3Hz away from 50Hz, and 0 voltage excursions | M |
| **RRE 1J** | **CNI Outages** | 0 outages in December | M |
| **RRE 2B** | **Diversity of service providers** | Varying diversity of providers across the different markets | Q |
| **RRE 2E** | **Accuracy of Forecasts for Charge Setting** | 17% forecasting error in December | M |

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

### Q3 2021-22 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 *(£m)*** = (Outturn Wind *(TWh)* x 12.16 *(£m/TWh)*) + 19.75 *(£m)* + 41.32 *(£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.

**Figure 1: Monthly balancing cost outturn versus benchmark (£m)**

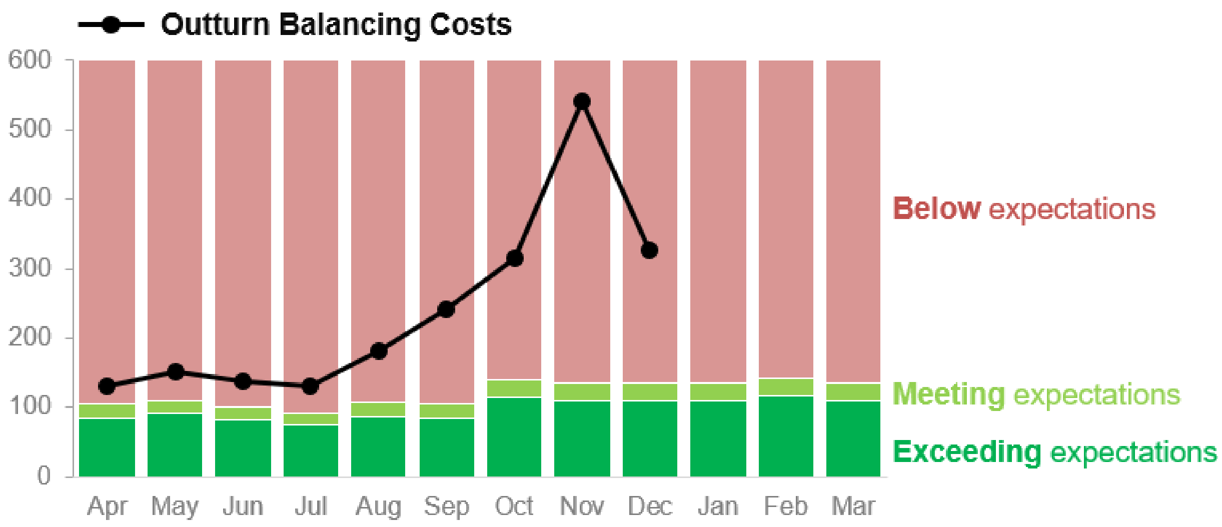



**Table 3: Monthly balancing cost benchmark and outturn** (Apr-Dec 2021)

| All costs in £m | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|
| Benchmark: non-constraint costs (A) | 41.3 | 41.3 | 41.3 | 41.3 | 41.3 | 41.3 | 41.3 | 41.3 | 41.3 | 371.7 |
| Indicative benchmark: constraint costs (B) | 59.9 | 50.6 | 52.3 | 49.2 | 58.4 | 66.9 | 76.3 | 75.0 | 82.2 | 570.7 |
| Indicative benchmark: total costs (C=A+B) | 101.2 | 91.9 | 93.6 | 90.5 | 99.7 | 108.2 | 117.6 | 116.3 | 123.5 | 942.5 |
| Outturn wind (TWh) | 2.8 | 3.2 | 2.5 | 1.9 | 3.0 | 2.8 | 5.5 | 5.1 | 5.1 | 31.7 |
| Ex-post benchmark: constraint costs (D) | 53.5 | 58.9 | 49.9 | 42.5 | 55.7 | 53.4 | 86.6 | 81.8 | 81.4 | 563.8 |
| **Ex-post benchmark (A+D)** | **94.8** | **100.3** | **91.2** | **83.8** | **97.1** | **94.8** | **128.0** | **123.1** | **122.7** | **935.7** |
| **Outturn balancing costs**[1] | **130.0** | **151.6** | **137.8** | **130.9** | **182.5** | **239.9** | **316.9** | **541.5** | **327.2** | **2158.2** |
| **Status** | ● | ● | ● | ● | ● | ● | ● | ● | ● | ● |

**Restoration is included from April 2021:** Please note that the 2020-21 incentivised balancing cost figures did not include costs for restoration, but from April 2021 these are included.

## 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

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

## Supporting information

### December performance

The balancing costs for December were £327.2m, which is more than £200m lower than the November figure of £541.5m, but still in the 'below expectations' range. Both constraint and non-constraint costs remain higher than last year, but have decreased since November when the spend was the highest on record. The main drivers for the high costs this month were large volumes of Balancing Mechanism (BM) actions to reduce generation to manage thermal constraints on windy days, and expensive operational intervention to replace sterilised headroom.

### Q3 performance

The total balancing costs for October to December (£1,186m) were higher than those for the previous 6 months combined (£973m), and significantly higher than the outturn in Q3 last year (£523m). Balancing costs rose sharply between October 2021 and November 2021, with November's balancing spend being the highest on record. December's balancing costs decreased from the previous month but remain very high and broadly in line with October's costs.

Both constraint and non-constraint costs in Q3 were significantly higher than those for the same period of the previous financial year.

The significant increase in non-constraint costs compared with last year was the result of tight system margins, scarcity pricing, and high gas prices driving up prices for Operating Reserve, Fast Reserve and Response.

Response costs were impacted by the introduction and development of the Dynamic Containment response service, which increased the overall response requirement. Volume previously procured in the Firm Frequency Response market has moved over to the Dynamic Containment market which has reduced competition in the Firm Frequency Response market and resulted in lower volumes procured through this avenue. This has left more requirement to be filled in the BM while these markets are developing and competition increases. The response procured in the BM is particularly affected by the increase in energy costs, i.e. where the cost of the action needed is increased.

The significant increase in constraint costs, particularly in November, was the result of continued very high wholesale prices, combined with high wind and reduced boundary capability due to system outages. This required us to take a large volume of Balancing Mechanism (BM) actions to reduce generation behind constraints and replace it with alternative generation.

## Breakdown of costs vs previous month

**Balancing Costs variance (£m): December 2021 vs November 2021**

| | | (a) Nov-21 | (b) Dec-21 | (b) - (a) Variance | decrease ◄► increase Variance chart |
|---|---|---|---|---|---|
| **Non-Constraint Costs** | Energy Imbalance | 11.1 | 6.7 | (4.4) | |
| | Operating Reserve | 72.5 | 44.9 | (27.6) | |
| | STOR | 7.8 | 5.6 | (2.2) | |
| | Negative Reserve | 2.3 | 0.8 | (1.5) | |
| | Fast Reserve | 23.1 | 21.5 | (1.6) | |
| | Response | 26.5 | 24.1 | (2.4) | |
| | Other Reserve | 2.8 | 1.7 | (1.1) | |
| | Reactive | 19.2 | 23.4 | 4.2 | |
| | Black Start | 4.9 | 4.2 | (0.6) | |
| | Minor Components | 10.2 | 10.1 | (0.1) | |
| **Constraint Costs** | Constraints - E&W | 41.6 | 18.2 | (23.5) | |
| | Constraints - Cheviot | 12.3 | 20.9 | 8.5 | |
| | Constraints - Scotland | 126.4 | 58.3 | (68.1) | |
| | Constraints - Ancillary | 2.7 | 0.5 | (2.1) | |
| | ROCOF | 6.9 | 3.3 | (3.6) | |
| | Constraints Sterilised HR | 171.2 | 83.1 | (88.1) | |
| **Totals** | Non-Constraint Costs - TOTAL | 180.4 | 142.9 | (37.5) | |
| | Constraint Costs - TOTAL | 361.1 | 184.3 | (176.8) | |
| | **Total Balancing Costs** | **541.5** | **327.2** | **(214.3)** | |

As shown in the total rows above, the majority of this month's decrease in costs came in constraint costs which reduced by £176.8m, whilst non-constraints costs fell by £37.5m. However, we note that November 2021 had the highest balancing costs on record, so although costs have fallen in December, they are still considerably higher than the benchmark and significantly higher than historically observed costs.

Within the constraint category, the breakdown shows that Constraints-Cheviot was the only category showing a cost increase from the previous month, which is £8.5m higher. Reactive was the only non-constraint category that increased, going up by £4.2m.

Overall, Operating Reserve, Constraint-Scotland, and Constraint Sterilised Headroom were the categories with the largest decrease from November.

The main drivers of the biggest changes this month are detailed below:

1. **Constraint Sterilised Headroom: £88.1m decrease.** The cost reduction is in line with the reduction of constraint actions in Scotland (see point 2 below), as less headroom had to be replaced elsewhere outside the constraint through BM actions. See definition below.
2. **Constraint-Scotland: £68.1m decrease.** Over the first two weeks of the month, constraints actions were needed due to windy weather that required us to take a large volume of BM actions to reduce generation output in Scotland to manage thermal constraints. No costs were incurred to resolve constraints within Scotland for the last two weeks of December, resulting in an overall reduction in the volume of BM actions compared to November.
3. **Constraint-Cheviot: £8.5m increase.** The cost increase was driven by an increase in the volume of BM actions to manage power flow restrictions on the Scotland-England network boundary to solve thermal constraints, particularly over the last seven days of the month.

### Explanation of Constraints Sterilised Headroom

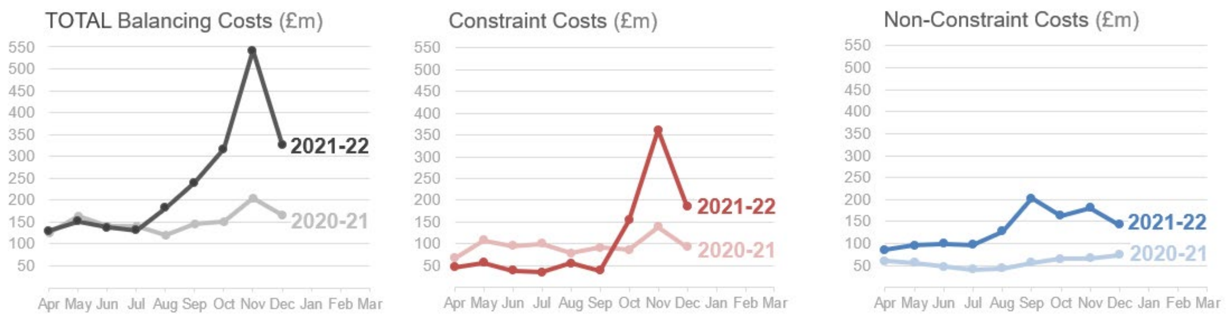
When the ESO takes balancing actions (bids and offers) to redispatch generation to resolve a system constraint (e.g. a thermal or voltage constraint), the total cost of the bids and offers which are taken to resolve the constraint are normally categorised as constraint costs, and contribute to the line items within the constraint costs section of the table above (such as E&W).

However, in a situation where margins are tight, the cost of the offer (replacement energy) would be higher than usual. In this situation, some costs (associated with the offer) would be categorised as Constraint Sterilised Headroom, rather than one of the other Constraint categories.

Constraints Sterilised Headroom is the result of post-event categorisation of balancing actions, rather than an action consciously taken by the Control Room.

## Constraint Costs vs Non-Constraint Costs

*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 for December and for Q3 as a whole are significantly higher this year than for the same period last year.  Overall constraint costs have risen in Q3, exceeding the previous year with a significant cost increase in November. The planned outage volumes ahead of clock change in October, and the large volume of actions required to manage the constraints throughout the three months were the main drivers behind the high spend. Although December 2021's non-constraint costs were lower than the previous two months they have been much higher than they were in Q3 last year, due to tight system margins and high gas prices.

**Constraint Costs**

Compared with the same month (December) of the previous year:

Constraint costs have outturned £92m higher than in 2020 this month due to:

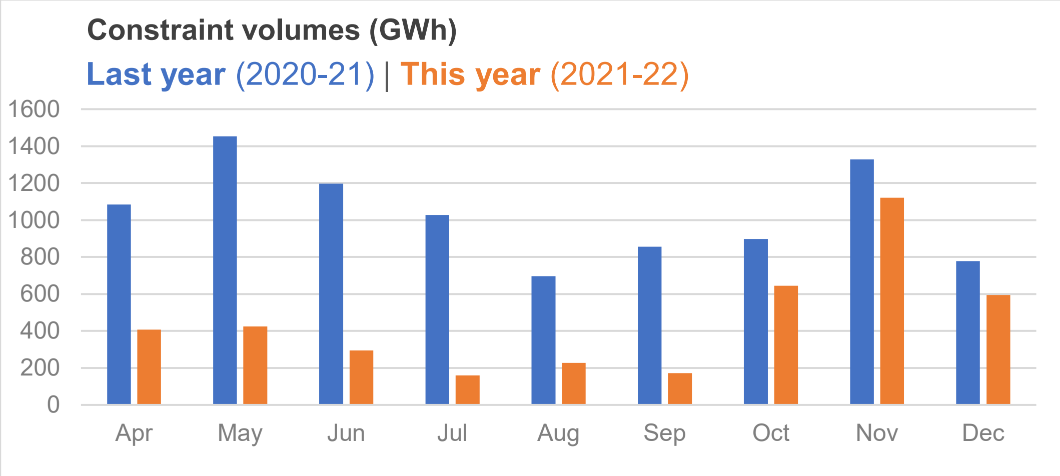
- An increased cost of actions to manage thermal constraints and network congestion during high wind periods.
- Increased spend for replacement energy and headroom associated with wind driven constraints in Scotland.

Compared with November 2021:

Constraint costs were £176.8m lower than in November due to:

- Improved boundary availability which required fewer BM actions to constrain off generation and replace energy & headroom elsewhere.

**Constraint volumes**




Compared to December 2020, December 2021 had a lower volume of constraint actions, despite the cost outturning higher.

Compared with 2020-21, this year has been a year of consistently lower volumes of actions for constraints.

Both of these comparisons show that it is the cost of the actions required rather than the volume which is driving the overall constraint cost.

**Non-Constraint Costs**

Compared with the same month (December) last year:

Non-constraint costs for December were £69m higher than the same month last year due to:

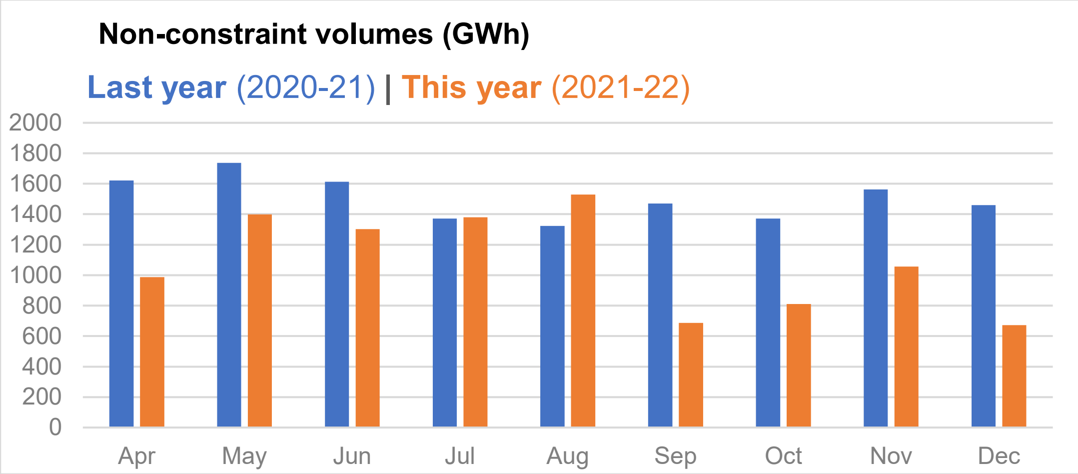
- Continued high prices submitted, or resubmitted in the BM and at the Day Ahead market stage. This means the actions which the ESO needs to take are only available at high costs. This impacts on the costs of Operating Reserve and Fast Reserve.
- Response costs remain higher than in 2020 due to the introduction of the Dynamic Containment service, and the changed requirement for response holding. This has meant a higher volume of response has been procured, and at a higher price than in 2020. There is a related reduction in the RoCoF spend within the constraint costs due to the phased implementation of the Frequency Risk and Control Report (FRCR) throughout the year.

Compared with November 2021:

Non-constraint costs were £37.5m lower than in November due to:

- Less costly Operating Reserve actions

## Non-constraint volumes

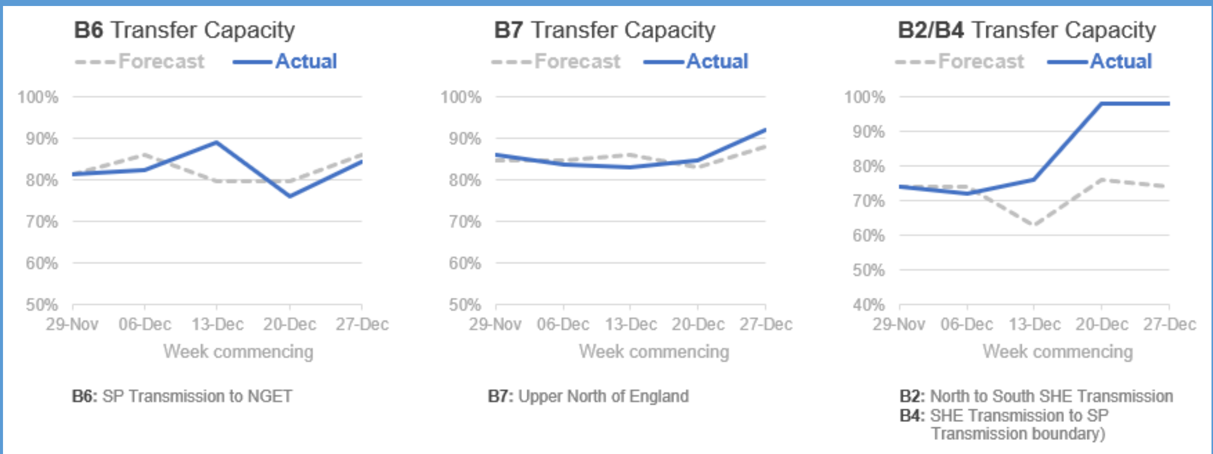



Compared with December 2020, December 2021 had a significantly lower volume of actions taken for non-constraint reasons despite the cost outturning higher.

Compared with FY 2020-21, this year has been a year of consistently lower volume of action for non-constraints with July and August the only outliers.

Both of these comparisons show that it is the cost of the actions required rather than the volume which is driving the overall non-constraint cost.

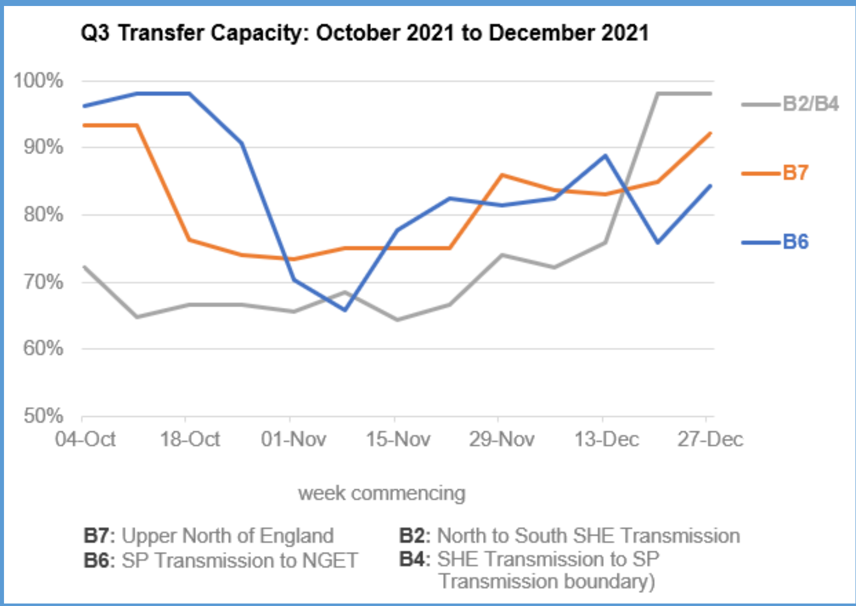
## Network availability



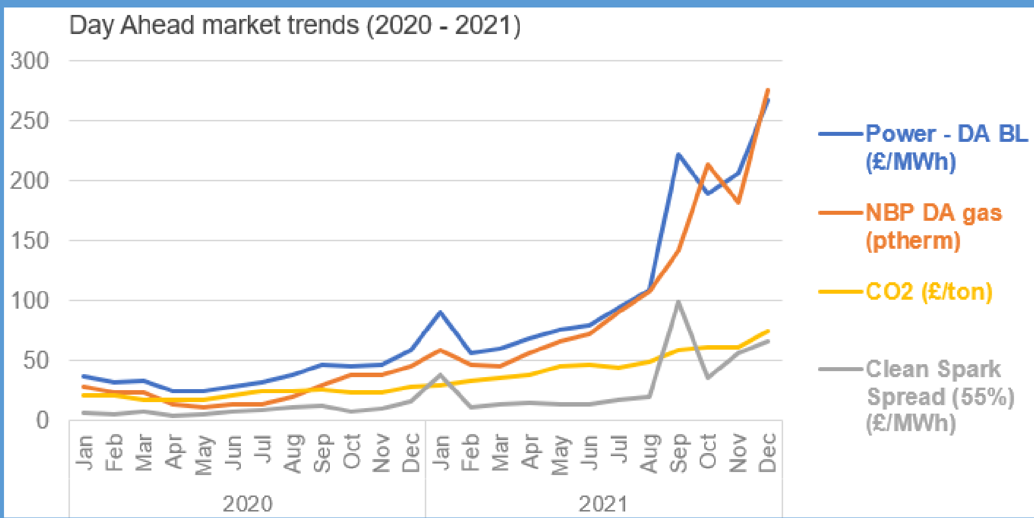

Transfer capacity has been in line with or above the forecast for the majority of the month. The reduced transfer capacity combined with windy conditions on some days led to the need for actions to manage these constraints.

As shown in the graph below, boundary capacity has been higher than or in-line with the previous month. Therefore, given the weather conditions, lower constraint costs would be expected and have outturned.

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

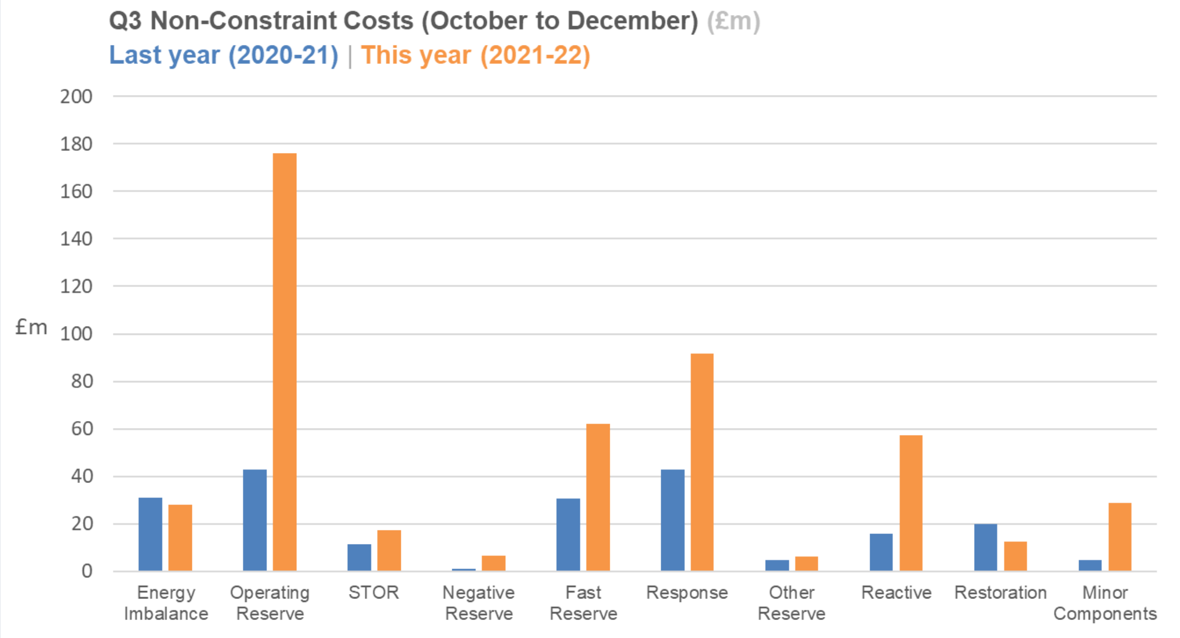



**DA BL:** Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have continued to increase in December and remain very high compared to the previous year. The day ahead gas prices have risen again in December and again, remain very high in comparison with 2020. Carbon prices continue the upward trend seen throughout 2021.

These continued higher prices impact on both the buy (offer) and sell (bid) actions available to the ESO to manage our operability requirements. This demonstrates some of the external drivers of the underlying high prices available to ESO for balancing actions.

## Cost trends vs seasonal norms




Comparing the Q3 (October 2021 – December 2021) energy costs with those of the same period last year, we can see that there has been a rise in all categories, except restoration.

- **Operating Reserve** costs have increased by £133m, driven by the high cost of BM actions. This in some part relates to the continued high wholesale market prices.
- **Fast Reserve** costs have increased by £31m, due to the higher market prices impacting on BM actions available to ESO.
- **Response** costs have increased by £49m. With the introduction of the Dynamic Containment service, this continues to be a higher spend than the previous year. There is a reduction in constraint costs due to a reduction in the actions required to manage RoCoF as a result of the introduction of the FRCR.
- **Reactive costs** have increased by £41m. As the volume of actions taken is in line with seasonal norms, the increase in spend is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.

## Drivers for unexpected cost increases/decreases

Margin prices (the amount paid for a single MWh) have fallen since November but remain high when compared to last year. The margin prices for Q3 as a whole are also significantly higher than the same period last year. This is due to the higher prices offered for actions required to be taken and due to the increased volume of actions taken to make more generation available to meet our operational margin requirements.

### Daily costs trends

As discussed above, December balancing costs were £214.3m lower than the previous month.

However, we counted four days that recorded a spend above £20m and two additional days with a spend above £15m. Windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints was the main driver behind the expensive days during the month.

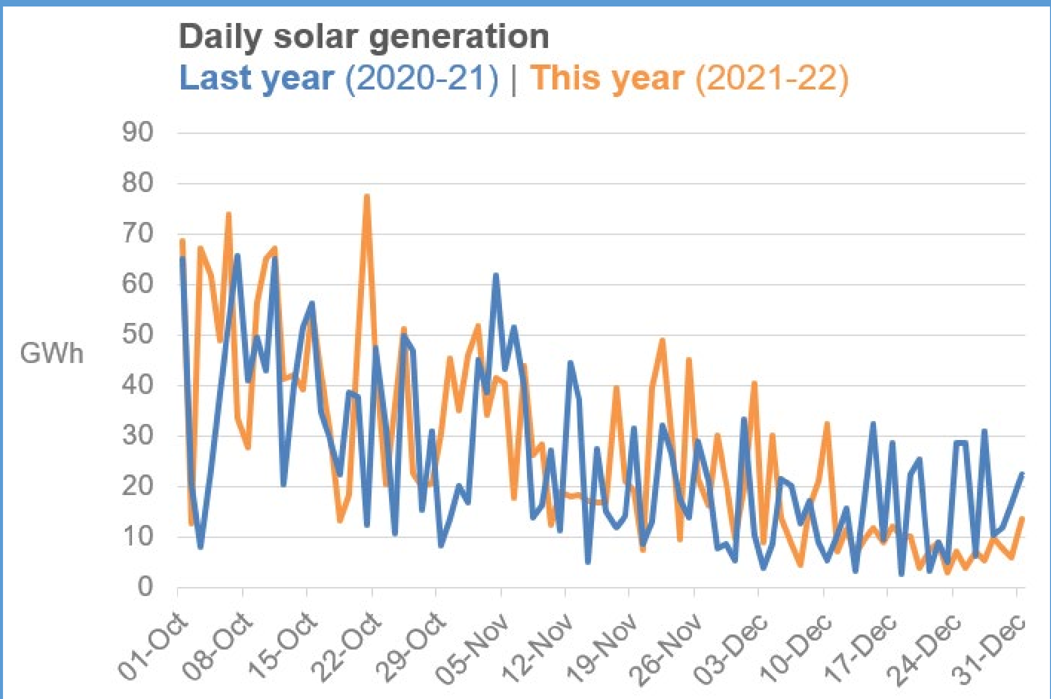
On Friday 3 December and Thursday 16 December, when costs outturned at £23.8m and £22.8m respectively, the main cost component was sterilised headroom. The combination of a reduced boundary capability due to system outages and the resultant need to reduce the output of generation behind a constraint, required  high cost BM actions to replace the sterilised headroom.

Other expensive days were Monday 13 December and Tuesday 14 December with an outturn of £23.8m and £21.3m respectively, and Monday 6 December and Saturday 25 December with a daily spend of £17.3m and £15.5m respectively.

### Significant events

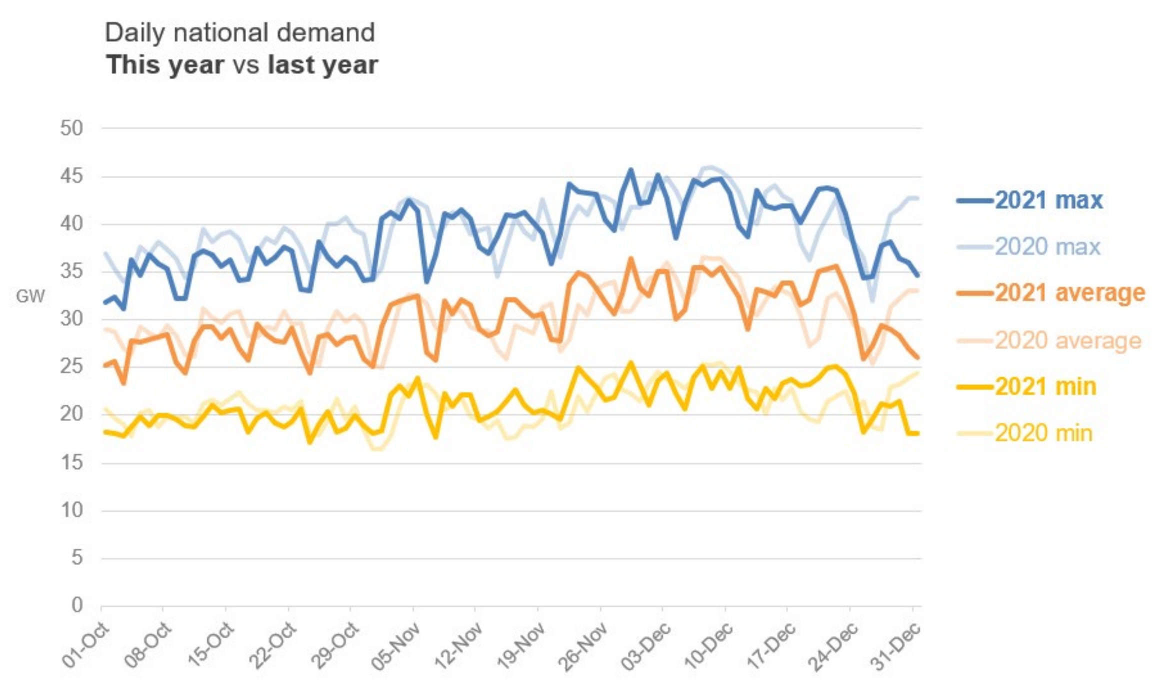
As detailed above, in recent weeks there have been several very high-cost days in the Balancing Mechanism. As those costs are ultimately borne by consumers it is important to fully understand the factors driving the market. The ESO is therefore undertaking a review of the balancing market as described in the Role 1 Notable Events section.

### Solar generation - comparison against last year




Compared to Q3 last year, solar generation was lower in Q3 2020-21. Solar generation was particularly low for the majority of December when compared to December 2020.

## Outturn Demand vs 2020-21




Outturn demand for Q3 this year has been relatively similar to the same period last year.

## Metric 1B Demand forecasting accuracy

### Q3 2021-22 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 shall 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.

Compared with last year's reporting, there are two differences in relation to metric 1B. The first one is that the performance is reported as the mean absolute percentage error (APE) rather than mean average error expressed in MW. The second difference is that the accuracy is measured for each Settlement Period, rather than each Cardinal Point.

**Figure 2: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)**

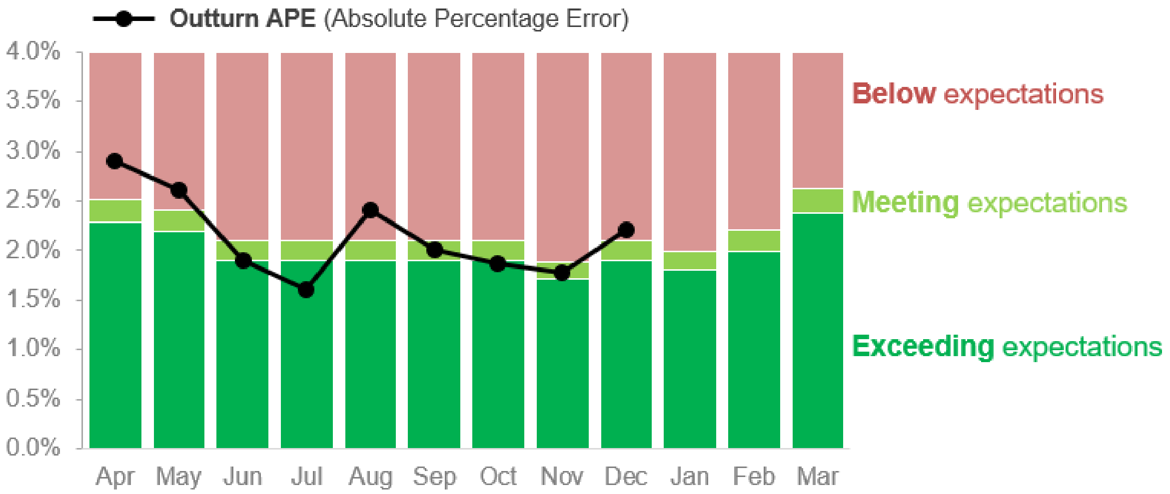



**Table 4: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)**

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Full Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Indicative benchmark (%) | 2.4 | 2.3 | 2.0 | 2.0 | 2.0 | 2.0 | 2.0 | 1.8 | 2.0 | 1.9 | 2.1 | 2.5 | **2.1** |
| APE (%) | **2.9** | **2.6** | **1.9** | **1.6** | **2.4** | **2.0** | **1.9**[2] | **1.8** | **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

[2] It has been identified that the figure of 2.0% (rounded from 1.95%) reported for October 2021 was incorrect, and has been updated to the correct figure of 1.9% (rounded from 1.87%). As a result, the October status has changed from 'meeting expectations' to 'exceeding expectations'.

## Supporting information

For **December 2021**, our MAPE (mean absolute percentage error) was 2.2% compared to the benchmark of 2.0% and therefore below expectations. For **Q3** as a whole, our performance is meeting expectations, with one month exceeding, one month meeting and one month below expectations.

### Commentary for Q3

| | |
|---|---|
| **October**<br>*Exceeding expectations* | Throughout the month, performance was comfortably within the benchmark, although the impact of the clock change weekend, which is a time when forecasting uncertainty is heightened, made the overall MAPE worse than it otherwise would have been. |
| **November**<br>*Meeting expectations* | We met expectations despite November's benchmark being the most challenging of the year, at 1.8%. Storm Arwen and its remnants impacted on performance, with Sunday 26 November & Monday 27 November being the most challenging days in the month to forecast due to the storm. |
| **December**<br>*Below expectations* | Saturday 25 December and Sunday 26 December were the most challenging days in the month to forecast. The last time the Christmas holidays followed this pattern (Christmas Day and Boxing Day during the weekend and substitute bank holidays on the following Monday and Tuesday) was in December 2010, when the amount of renewable generation capacity available on the system was substantially lower, and when demand levels were not impacted by the COVID-19 pandemic.<br>Performance in December was affected by the consequences of the rapid spread of the Omicron variant of COVID-19, which resulted in a large number of people infected, forced to self-isolate or minimising social contact to avoid the risk of the virus. On 8 December, the government announced guidance to work from home where possible from 13 December, which introduced another layer of uncertainty.<br>Holidays were also somewhat distorted by travel restrictions imposed by other countries, resulting in more people staying at home.<br>In addition, in December there was more uncertainty of demand levels during the Darkness Peak, resulting from Triad avoidance as explained below. |

We continue to use two forecasting models which run in parallel, with the models' outputs reviewed by experienced forecasters who determine the final forecast.

**Performance in December 2021: big errors**

| Error greater than | No of SPs | % out of the SPs in the month (1488) |
|---|---|---|
| 1000MW | 318 | 21% |
| 1500MW | 133 | 9% |
| 2000MW | 74 | 5% |
| 2500MW | 45 | 3% |
| 3000MW | 31 | 2% |

### Triads

December is the second month of the 2021-22 triad season. 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. The “triad avoidance” 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 and also shared on the newly created ESO Data Portal in the following dataset: Day Ahead Half Hourly Demand Forecast Performance.

There were 0 occasions of missed or late publications in Q3.

## Metric 1C Wind forecasting accuracy

### Q3 2021-22 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 (2021-22)**

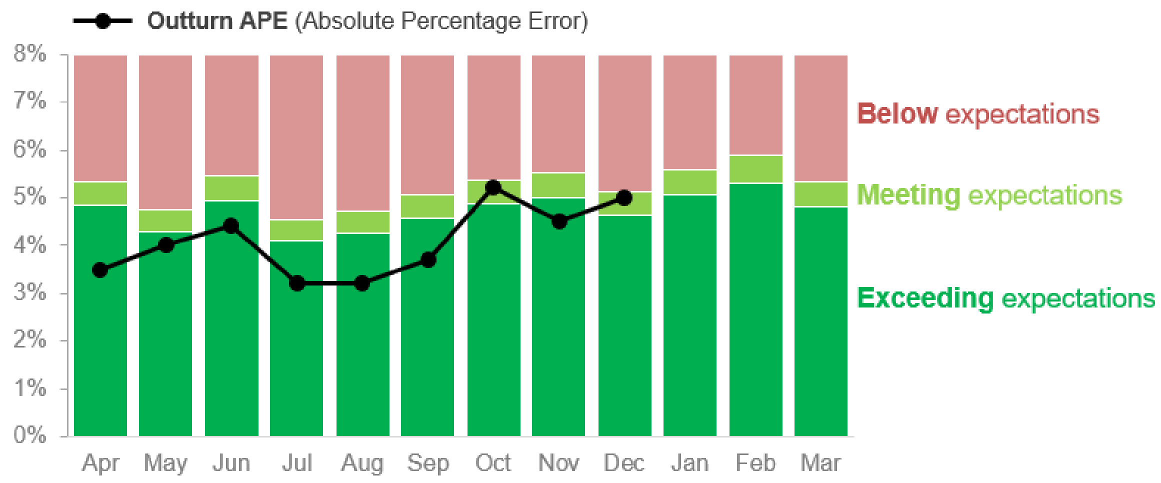



**Table 5: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)**

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | Full Year |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| BMU Wind Generation Forecast Benchmark (%) | 5.1 | 4.5 | 5.2 | 4.3 | 4.5 | 4.8 | 5.1 | 5.3 | 4.9 | 5.3 | 5.6 | 5.1 | **5.0** |
| APE (%) | **3.5** | **4.0** | **4.4** | **3.2** | **3.2** | **3.9** | **5.2** | **4.5** | **5.0** | | | | |
| 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 **December 2021**, our MAPE (mean absolute percentage error) was 5.0% compared to the benchmark of 4.9% and therefore meeting expectations.

For **Q3** as a whole our performance has been meeting or exceeding expectations in all three months.

**Commentary for Q3**

| | |
|---|---|
| **October**<br><br>*Meeting expectations* | October is usually the month when the weather transitions into the stormier Winter phase and we faced forecasting challenges with multiple low pressure centres active at the same time. Despite this, our MAPE for October was 'meeting expectations'. |
| **November**<br><br>*Exceeding expectations* | November is the month in which the weather can be the most difficult to predict, and with the remnants of ex-Tropical Storm Wanda passing over the UK, and Storm Arwen also appearing late in the month, these brought challenges. Despite these factors, our performance was 'exceeding expectations' with a MAPE of 4.5% compared to the benchmark of 5.3%. |
| **December**<br><br>*Meeting expectations* | December is traditionally a turbulent month where the number and intensity of storms arriving to the UK is governed by the position and intensity of the jet stream.<br><br>For the mid part of December between 12th and 24th the jet stream faded and was very weak. This coincided with a period of low wind, an absence of stormy conditions and greater forecast accuracy. For the remainder of December the jet stream fluctuated from the North to the South of the UK bringing stormy conditions on the following dates:<br><br>• On Friday 3 December two areas of low pressure arrived at the UK at the same time: one arriving at Southwest England and the other at Western Scotland. The interaction between these systems increased the possibility of weather forecast errors.<br><br>• 6, 7 and 8 December brought Storm Barra. This storm travelled directly across the Republic of Ireland and towards Liverpool and Manchester. As it arrived over England the low pressure system rapidly filled in and the wind speeds dropped considerably from what had been a very powerful storm. It is unusual to see a storm fade so rapidly.<br><br>Wind farms with Contract for Difference (CfD) contractual arrangements switch off for commercial reasons while prices are negative for 6 hours or more. In December there were no occasions when the electricity price went negative for 6 hours or more. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for December can be downloaded from here. |

The performance in Q3 continues to be supported by the improvements delivered during 2020-21 as part of the Platform for Energy Forecasting (PEF) project. These changes mean that we now produce forecasts more frequently and at a higher level of detail.

The other factor to consider is the impact of COVID-19. Due to social distancing and other requirements introduced to manage the pandemic, the rate of construction of new wind farms has been lower than it otherwise would have been. New wind farms are a source of forecasting error since the models have not been refined in light of metered data. With a greater proportion of mature wind farms a higher level of accuracy can be achieved.

# Metric 1D Short Notice Changes to Planned Outages

## Q3 2021-22 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**

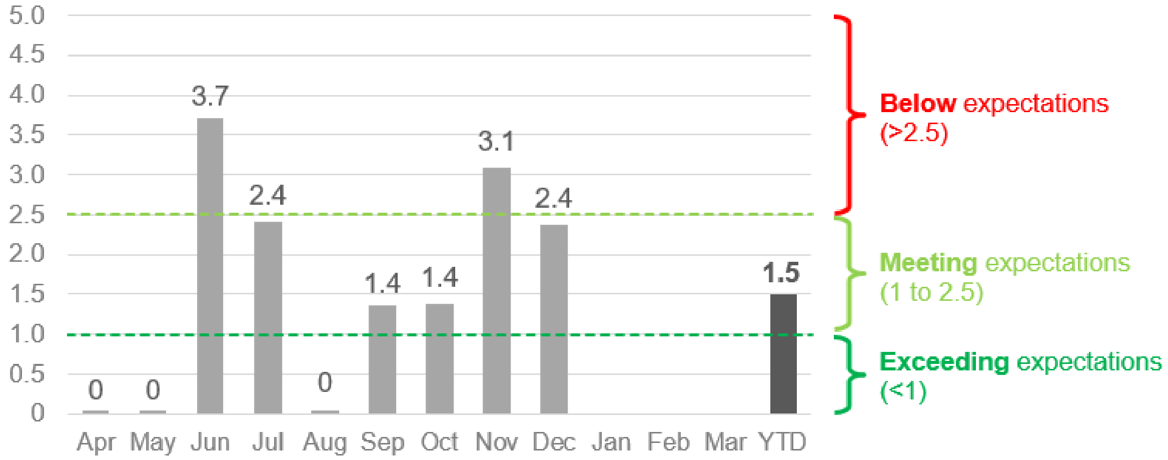



**Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages**

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Number of outages | 845 | 856 | 810 | 831 | 810 | 735 | 723 | 648 | 423 | | | | 6681 |
| Outages delayed/cancelled | 0 | 0 | 3 | 2 | 0 | 1 | 1 | 2 | 1 | | | | 10 |
| Number of outages delayed or cancelled per 1000 outages | 0 | 0 | 3.7 | 2.4 | 0 | 1.4 | 1.4 | 3.1 | 2.4 | | | | 1.5 |

## 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

**December performance: Meeting expectations**

For December, the ESO has successfully released 423 outages and there has been a total of one delay and no cancellations due to an ESO process failure. This gives a score of 2.4 per 1000 outages which is within the ‘meeting expectations’ range of 1-2.5 per 1000 outages.

**Q3 performance: Meeting expectations**

For Q3 as a whole, the total delays or cancellations due to an ESO process failure is 4. This gives a Q3 score of 2.2 per 1000 outages which is within the 'meeting expectations' range of 1-2.5 per 1000.

This is a better performance than Q3 last year (October to December 2020) when there were 2.4 cancellations or delays per 1000 outages.

**Details of the 4 delays / cancellations due to an ESO process failure in Q3:**

| | |
|---|---|
| **October**<br>*1 event* | • The single event in October was a situation where one outage was delayed by the TO which impacted another planned outage, this resulted in two outages overlapping that could not take place simultaneously due to the impact it would have on a connected customer. The overlap of the two outages, that could not occur simultaneously, was missed by human error and was not identified in the outage planning database eNAMS. An Operational Learning Note (OLN) was written to identify the corrective actions for missing the knock-on impact initially |
| **November**<br>*2 events* | • The first event in November was a Transmission Operator (TO) outage where a non-standard outage combination was required leaving a Super Grid Transformer (SGT) and generator on one section of the substation. The ESO agreed with the Distribution Network Operator (DNO) to off-load the SGT in advance of the outage, and it was assumed that the generator would disconnect itself automatically in the event of a busbar fault. The risks were not fully discussed with the generator until the ESO control room contacted them over the weekend ahead of the Monday on which the outage started. The generator requested a circuit breaker protection modification at the substation which the TO was unable to deliver. Therefore, the TO decided not to proceed with this outage. An Operational Learning Note (OLN) was written that identifies corrective measures of highlighting non-standard outage combinations with the power station to facilitate discussions on substation running arrangements and options for modifying protection settings.<br>• The second event was a delay caused by concerns within control room timescales that voltage limits would be exceeded in the event of a fault. Studies carried out by the Network Access Planning team ahead of real time had not highlighted this issue, but the real-time model used by the Control Room showed different results. Our investigation into the discrepancy between the two models is ongoing, and discussion are also taking place regarding whether our internal planning tolerances need to be reviewed to further compensate for the discrepancies between the tools. |
| **December**<br>*1 event* | • The final event for Q3 was in December where the TO had requested a busbar outage within a substation. Prior to this outage, one of the three Super Grid Transformers (SGT) supplying the DNO demand was faulted and following repair was unable to be returned to service without disrupting another customer's supply. Within the outage planning database eNAMS, it showed that the SGT was available as the repair had been fixed by the TO. However, it was missed by the planning department that the SGT, whilst available, was off-load. When the outage was requested within control timescales, the DNO demand was not securable following the next credible fault and the DNO was not agreeable to the risk. As a result the outage was delayed by one day until agreement from another customer was obtained to return the SGT before taking the busbar outage. An Operational Learning Note (OLN) is being written to identify any corrective measures. |

## RRE 1E Transparency of operational decision making

### Q3 2021-22 Performance

This Regularly Reported Evidence (RRE) shows % 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 where 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.

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

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec |
|---|---|---|---|---|---|---|---|---|---|
| Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied) | 90.4% | 88.4% | 89.3% | 89.0% | 88.4% | 89.1% | 92.6% | 88.4% | 91.2% |
| Percentage of actions that have reason groups allocated (category applied, or reason group applied) | 99.6% | 99.6% | 99.7% | 99.8% | 99.8% | 99.7% | 99.9% | 99.7% | 99.8% |
| Percentage of actions with no category applied or reason group identified | **0.4%** (173) | **0.4%** (147) | **0.3%** (56) | **0.2%** (87) | **0.2%** (81) | **0.3%** (109) | **0.1%** (61) | **0.3%** (232) | **0.2%** (93) |

## Supporting information

This month 91.2% 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. We were unable to allocate reason groups for 0.2% of the total actions this month.

During Q3 (October 2021 to December 2021) as a whole, we sent 167,695 BOAs (Bid Offer Acceptances) and of these, only 386 remain with no category or reason group identified, an average of 0.2%.

# RRE 1F Zero Carbon Operability Indicator

## Q3 2021-22 Performance

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

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

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

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

**Part 1 – Defining the maximum ZCO limit for BP1**

The ESO will define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP1, explaining which deliverables are critical to increasing the limit.

**Table 8: Forecast maximum ZCO% after our operational actions**

| BP1 2021-23 | Maximum ZCO limit | Calculation and rationale |
|---|---|---|
| Start of BP1 (Q1 2021-22) | **80% - 85%** | The calculation of the maximum ZCO limit for the start of BP1 is based on the generation plant mix. We assume that the zero-carbon generation output is high, i.e. it is windy with significant contributions from nuclear, pumped storage and hydro, and then overlay system constraints. This overlay reduces the final ZCO as we remove zero carbon generation and add on carbon-producing generation such as CCGT or biomass to meet our response, inertia and voltage requirements. This range is compared with real-world system data to ensure consistency. For example, we are forecasting a maximum ZCO limit of between 80% to 85% and the April maximum ZCO figure is 84.6%. |
| End of BP1 (Q4 2022-23) | **85% - 90%** | The forecast of the maximum ZCO limit that the system can accommodate at the end of BP1 uses a very similar methodology. However, we factor in our forecast changes to the generation mix and significant operational developments. These developments are in line with our operational strategy and more detail is set out in our Operability Strategy Report. The most significant developments that impact ZCO will be improvements to our new response products, the stability pathfinders, stability market, the accelerated loss of mains change programme, the implementation of the Frequency Risk and Control methodology, the voltage pathfinders and reactive reform. All of these developments are increasing our ability to operate a zero carbon system by either increasing the operability envelope where secure system operation is possible, or by enabling new zero carbon providers of ancillary services. |

**Part 2 – Regular reporting on actual ZCO**

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

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

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in Q3 was 95% on 6 November, settlement period 47. However, for that period the final ZCO dropped to 77% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month. Figure 6 further below shows the underlying data by settlement period and highlights when the maximum monthly values occurred.

**Table 9: Q3 maximum zero carbon generation percentage by month**

| **Month** | **Highest ZCO% in the month** (after ESO operational actions) | **ZCO% provided by the market** (during the same day and settlement period) | **Date / Settlement Period** |
|---|---|---|---|
| April | 84.6% | 91.5% | 05 Apr / SP29 |
| May | 79.4% | 89.2% | 04 May / SP6 |
| June | 71.7% | 75.1% | 14 June / SP6 |
| July | 72.8% | 85.7% | 29 Jul / SP9 |
| August | 74.8% | 92.7% | 16 Aug / SP11 |
| September | 77.4% | 88.9% | 30 Sep / SP48 |
| October | 83.2% | 90.1% | 31 Oct / SP13 |
| November | 83.4% | 94.5% | 01 Nov / SP1 |
| December | 84.3% | 90.6% | 25 Dec / SP15 |

**Figure 5: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred)**

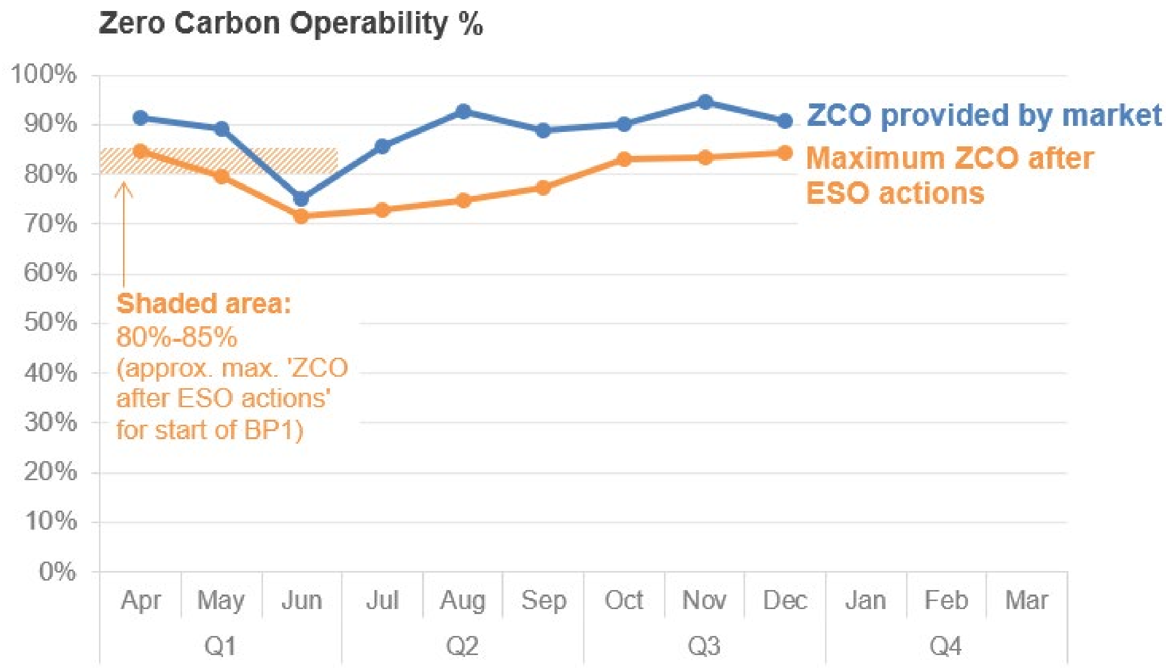
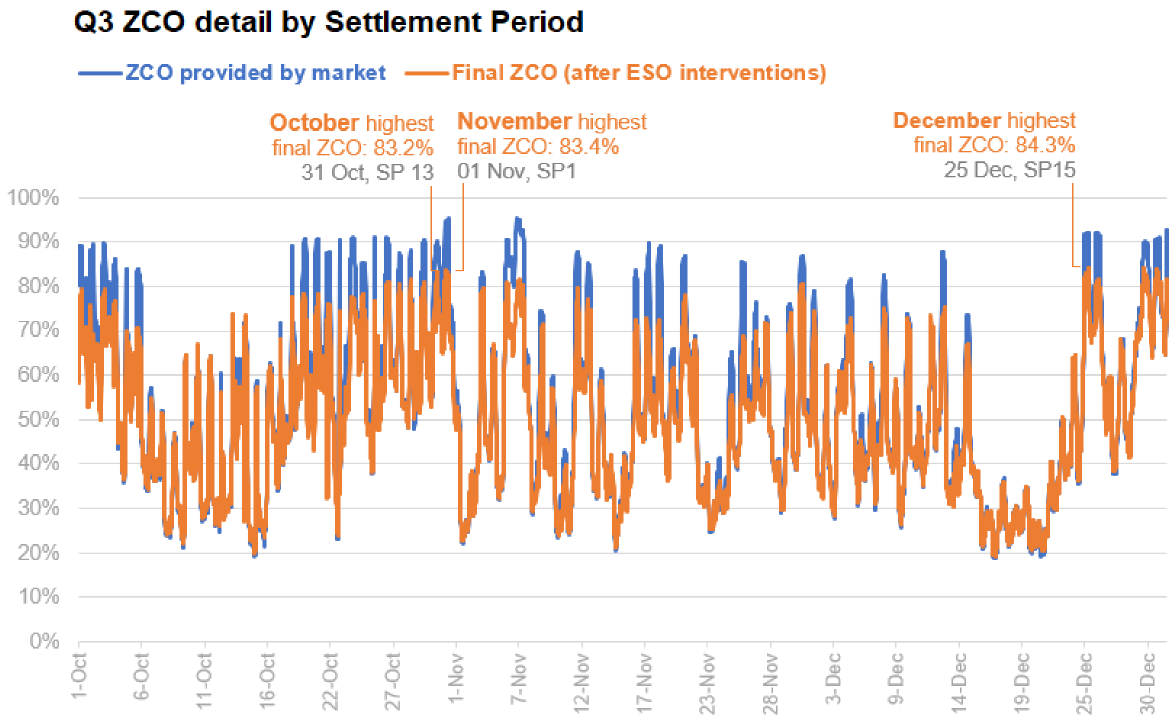



**Figure 6: Q3 ZCO by Settlement Period, before and after ESO operational actions**



## Supporting information

The highest zero carbon percentage outturn in Q3, following ESO actions was 84.3%, which occurred on 25 December, Settlement Period (SP) 15. During that SP the market provided 90.6% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 84.3%.

As expected, the Q3 ZCO figures have increased since Q2 and are back to the level seen at the start of Q1. Q2 figures are lower than Q1 and Q3 because the demand (not shown on the graph above) was lower in Q2 due to warmer weather. At times like these, when the demand is low but the renewable output remains high, the ZCO after ESO actions is often lower. This is because we still have to take similar sets of actions (to manage operability constraints such as voltage) but these actions represent a larger proportion of the overall amount of generation.

The other point to note is how closely linked the ZCO figure is with wind output - the low wind spells during the middle of December are clearly visible on the graph above where the ZCO% drops below 30%. Conversely, the maximum ZCO figures align with settlement periods of high renewable output, such as when it is windy. Usually (but not exclusively), these figures occur at times of low solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will still be needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

Since April, two Stability Pathfinder Phase 1 service providers have gone live at Deeside and Keith. Together they increase system inertia by ~3.6GVAs, which could potentially remove the need to synchronise a Combined Cycle Gas Turbine (CCGT) unit for inertia. This usually occurs over the summer and shoulder months and would increase the ZCO figure by around 1%, dependent on system conditions. Going forward we expect to see further increases in ZCO as the other Stability Pathfinder Phase 1 projects commission.

## RRE 1G Carbon intensity of ESO actions

### Q3 2021-22 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.

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

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Carbon intensity (gCO2/kWh)** | 2.1 | 6.2 | 4.5 | 4.5 | 6.9 | 1.0 | 4.8 | 9.4 | 3.4 | | | |

### Supporting information

In December 2021 the average difference between the carbon intensity of FPNs (Final Physical Notifications) and balancing actions was 3.4 gCO2/kWh. The biggest increase following balancing actions was 42.10 gCO2/kWh and the biggest decrease was -20.16 gCO2/kWh.

The biggest decrease of -20.16 gCO2/kWh occurred on 11 December at 05:00am. The biggest decrease in carbon intensity in the whole Q3 period was -24.61 gCO2/kWh.

The biggest increase of 42.10 gCO2/kWh occurred on 7 December at 06:00pm. The biggest increase in the whole Q3 period was 90.92 gCO2/kWh.

For Q3 as a whole, the average carbon intensity of balancing actions was 5.85 gCO2/kWh. December 2021 (3.4 gCO2/kWh) had a lower average than both October 2021 (4.75 gCO2/kWh) and November 2021 (9.37 gCO2/kWh).

## RRE 1H Constraints Cost Savings from Collaboration with TOs

### Q3 2021-22 Performance

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

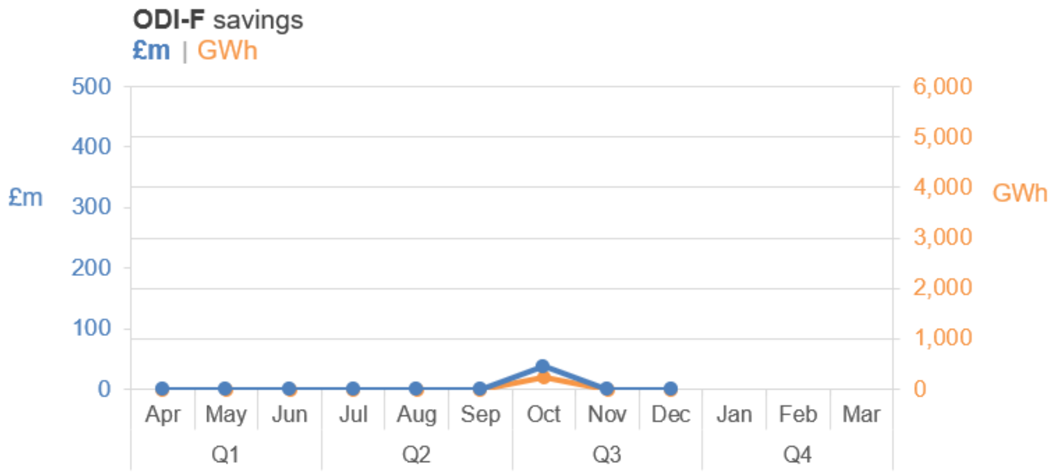
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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

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

**Figure 7: Estimated £m savings in avoided constraints costs (ODI-F)**

(Estimated savings in GWh are also shown for context)




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

**Figure 8: Estimated £m savings in avoided constraints costs (Other)**

(Estimated savings in GWh are also shown for context)

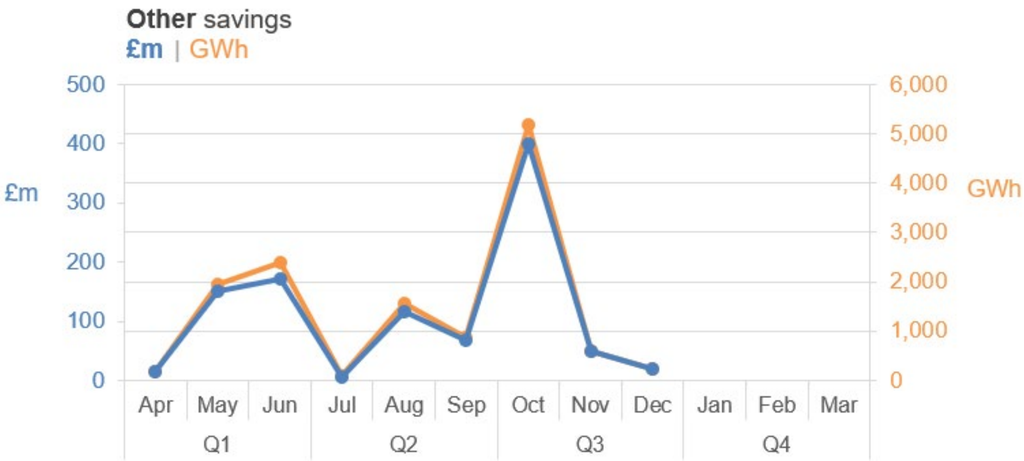



**Table 11: Estimated £m savings in avoided constraints costs**

| | | Jul | Aug | Sep | Jul | Aug | Sep | Oct | Nov | Dec | YTD |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **ODI-F** savings | £m | - | - | - | - | - | - | 38 | - | - | **38** |
| **Other** savings | £m | 15 | 151 | 171 | 6 | 116* | 68* | 401 | 49 | 19 | **994** |
| **ODI-F** savings | GWh | - | - | - | - | - | - | 244 | - | - | **244** |
| **Other** savings | GWh | 189 | 1,942* | 2,391 | 107 | 1,552* | 873* | 5,177 | 592 | 247 | **13,070** |

*The updates to previous months' figures are due to updating previous estimates when actual values become available.

## Supporting information

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

The Network Access Planning (NAP) team has progressed and approved six enhanced service provisions from TOs through STCP 11.4 that provide constraint cost savings this year. These are:

1. A temporary operating regime was agreed with the TO which allowed sufficient time for manual post fault actions to be taken to secure the network. This was over a two-week period, when there was a lack of generation available in a specific part of the network to provide voltage support post fault. The enhanced service provision provided by the TO included providing additional personnel on site and in the control room, enhanced mitigation checks and dedicated monitoring equipment in place across three 400kV substations for a two-week period. This proposal was approved, alleviating the need to buy on 725MW of conventional generation and saving £37,830,000.
2. Changing the overload protection setting on a circuit which is due to provide continuous improvement to a constraint in the Dumfries and Galloway area saving thermal constraint costs. The savings from this initiative span the entire year and will be prorated over the full 12 months at the end of year when the value of the savings will be calculated. The installation of an overload protection scheme will allow increased flow across the SSE-SP boundary. Again, the savings from this initiative span the entire year and will be prorated over the full 12 months at end of year.

3. Provision of dynamic ratings on circuits 1 and 2 of a major transmission route in the North West of England to allow increased thermal loading based on expected weather conditions. The enhanced service provided by the TO included monitoring the limiting equipment, enhanced line checks and provision of daily ratings using dynamic weather data. This proposal has been approved as it is expected to increase the thermal boundary transfer capability in the local area by 200MW and will be used during future outages on either of these circuits. Estimated constraint costs savings are £24k per day during the next planned outage on the route
4. Increasing the rating on a circuit into the South East of England which allows an increase in the South-East import constraint limit.
5. Increasing the rating on circuits to allow the final high-priority decommissioning of circuits in central London.

In Q3 2021-22, NAP realised £38m of constraint cost savings through STCP 11.4. Some of the above active enhanced service provisions are yet to realise constraint cost savings due to these constraints not being active during this period. Others, as detailed in points 3 and 4 above cannot be captured in a single month in the ODI-F table below but rather will be prorated over the 12-month period at end of year.

However, some of the enhancements which are yet to realise savings will be useful in the coming months, and identifying and implementing these opportunities early has meant that the cost saving actions will be available over the winter period when they are most valuable.

In some cases, these opportunities for enhancement can only be delivered during outages to the relevant equipment. We are working with the TOs to ensure that this work can be delivered at minimum cost to the consumer by accommodating the work during existing planned outages, or by agreeing additional outages into the plan at optimal times.

STCP 11-4 opportunities, also proposed by ESO, and the TOs, that are in progress with the relevant TOs and will most likely be active in Q4 2021-22 include:

- Re-scheduling of asset replacement works to restore a circuit breaker from fault which controls a mechanically switched capacitor and is forecasted to increase the North England voltage constraint limit by 100MW.
- The temporary uprating on a major 275kV route in Central Scotland to allow an increase in North-South flows in Scotland during works on an adjacent 400kV route.
- Improved ratings on a Scotland – England boundary circuit which will increase the Scotland-England boundary thermal limit.
- There are initial discussions regarding the uprating of a cable in South West Scotland which have proved promising. The NAP team are currently carrying out a cost-benefit analysis for this.

**Other Savings (Customer Value Opportunities):**

The Network Access Planning team has made excellent progress over the last nine months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded over 135 instances (37 in Q3 2021-22) where the ESO's actions directly resulted in adding value to end consumers and its innovative ways of working facilitated increased generation capacity to connected customers.

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

In Q3 2021-22 NAP realised a total of **6,015,800 MWh which is approximately £467m**. Some examples of these instances in Q3 2021-22 include:

- The initial outage plan to deliver a new substation required a 29-week double circuit outage on a main transmission circuit in the main interconnected transmission system (MITS). The ESO worked with the TO to review the scheme and find ways to reduce the impact on the system, which resulted in taking one single circuit out of service at a time. Through this approach we released about 2,192,400MWh of renewable generation to the market, creating considerable value for the end consumer.
- A current year outage clashed with another scheme outage that was planned in year ahead timescales in the same geographical area. To secure this, the ESO would have needed to pull back 1000MW of generation in the South West of England for 9 days. The ESO worked in partnership with the TO to review all possible options to deliver the work whilst reducing the impact on the system. After careful optimisation, the TO worked to finish the year ahead works early, before commencing the current year outage. This action released about 216,000MWh of renewable generation to the market.
- The ESO, working with the TO, facilitated the formation of a temporary circuit in the South of Scotland to restore the MITS to minimise constraint costs and improve network conditions. This temporary circuit was suggested to facilitate access to the network when typically, it would be difficult to release due to the impact it has on the system. This action released about 2,227,200MWh of renewable generation to the market.

These and many more represent a total of **13,070,617MWh (approximately £994m)** of extra generation capacity, which would have otherwise been constrained at a cost to the consumer.

*(We assumed average values of £78/MWh for wind and £55/MWh for other generation)*

## RRE 1I Security of Supply

### Q3 2021-22 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. We will 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 12: Frequency and voltage excursions**

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

### Supporting information

There were no reportable voltage or frequency excursions in Q3.

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

## RRE 1J CNI Outages

### Q3 2021-22 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 13: Unplanned CNI System Outages** (Number and length of each outage)

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

**Table 14: Planned CNI System Outages** (Number and length of each outage)

| Planned | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Balancing Mechanism (BM) | 0 | 0 | 0 | 1 outage 216 minutes | 0 | 0 | 0 | 1 outage 215 minutes | 0 | | | |
| Integrated Energy Management System (IEMS) | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | | | |

### Supporting information

In Q3 there was one planned CNI system outage, in November 2021. The outage was required in order to deploy a software release of changes and enhancements to the BM production systems. The change impacted the key BM Suite components used for scheduling and dispatch of generation. As part of this outage, we were also able to plan and complete maintenance and configuration tasks to enable the continued focus on resilience of the system.

There were no unplanned outages during Q3.

## Notable events during Q3

### GE Digital's inertia measurement and forecasting service tool

In October we went live with an inertia measurement and forecasting service tool that we collaborated on with GE Digital. It measures frequency and power flow changes between regions of Britain 50 times a second to give our control engineers a real-time view of system inertia. It includes a machine learning model which also integrates with our control room system to give a 24-hour ahead forecast of system inertia – a vital view for our engineers in ensuring security of supply. As the first operational installation, the tool is currently in use by our business teams to understand the improved accuracy and develop the processes to integrate into our operational teams. Our intention is to launch this into the Control Room in Spring 2022 monitoring the inertia within Scotland as the first region, with the intention that it will be rolled out to all of GB once all Transmission Owners have installed the required monitoring devices.

### Reactive Technologies grid stability measurement service

In October, Reactive Technologies announced the launch of its flagship grid stability measurement service, developed with the ESO, following the construction of the world's largest continuously operating grid-scale ultracapacitor in Teesside. This unit is continuing to undergo testing and forms a critical part of the second innovative solution that will providing a real-time view of the system inertia. It is anticipated that the system will go live in Spring 2022.

### Virtual Energy System launched at COP26

On Friday 5 November, we announced the launch of an industry-wide programme to develop the Virtual Energy System[5] – a world first, real time replica of Great Britain's entire energy system. It will work in parallel to our physical system, affording a virtual environment through which we can share data, and model scenarios to make our decision-making more robust. On 1 December 2021 we also hosted a one-day conference which provided an opportunity for the energy industry and wider stakeholders to find out more about the programme, and how to get involved. We were joined by industry panellists and presenters from across Ofgem, BEIS, Energy Digitalisation Taskforce, Energy Systems Catapult and more.

### ESO sets out scope of balancing market review

On Monday 6 December, we set out three key areas in scope of our review of the balancing market. The first key area is a review of the bids into the balancing market on high-cost days since 1 August 2021, looking at price and technical parameters. The data review, alongside wider electricity market information, will be used to provide insights as to what might be driving the behaviours. Secondly, we will review the current market rules to determine whether there is anything inherent to them that is perpetuating the current behaviours. Thirdly, we will seek engagement from market participants to obtain insights on their current behaviours and their thoughts around current market rules.

We are still in the process of appointing the right consultants to undertake this piece of work who can provide meaningful insights and maintain impartiality. Once onboarded we will share a revised timeline for this piece of work and engagement with stakeholders. The terms of reference can be found on our website.[6]

[5] https://www.nationalgrideso.com/virtual-energy-system
[6] https://www.nationalgrideso.com/news/balancing-market-review-terms-reference

# Role 2 Market development and transactions

## Metric 2A Competitive Procurement

### Q3 2021-22 Performance

This metric measures the overall % of services procured through competitive means (auctions and tenders) calculated by £ expenditure.

Please note the following points when interpreting the data for this metric:

- For **Restoration**, there may be a significant lag time between when a contract is agreed and when it comes into effect. Therefore, in some cases actions we take in the current quarter may not impact Metric 2A until months or years later.

- For **Frequency Response** (FR), a lower '% of services procured through competitive means (auctions and tenders)' may appear to indicate that the market has become less competitive, but can actually be a sign of the opposite. When the market becomes more competitive, the market price drops. This can lead to a reduction in overall competitively procured spend and therefore a lower percentage of total services that are competitively procured.

**Figure 9: Percentage of £m spend by procurement method**

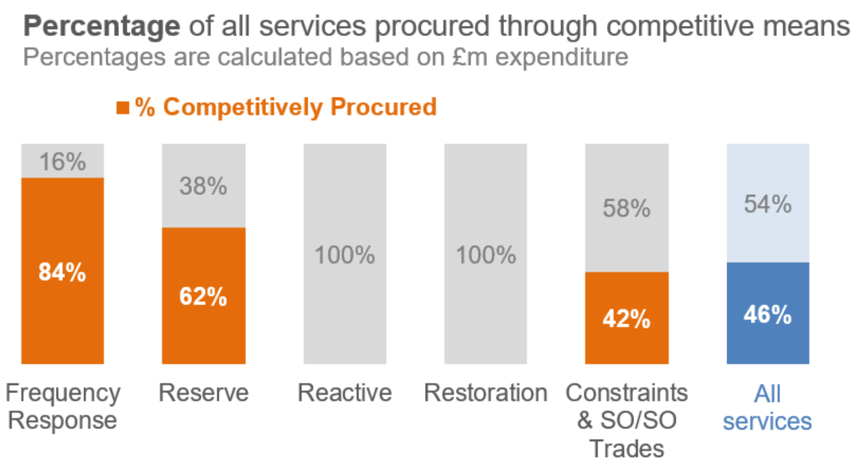



**Figure 10: Absolute £m spend by procurement method**

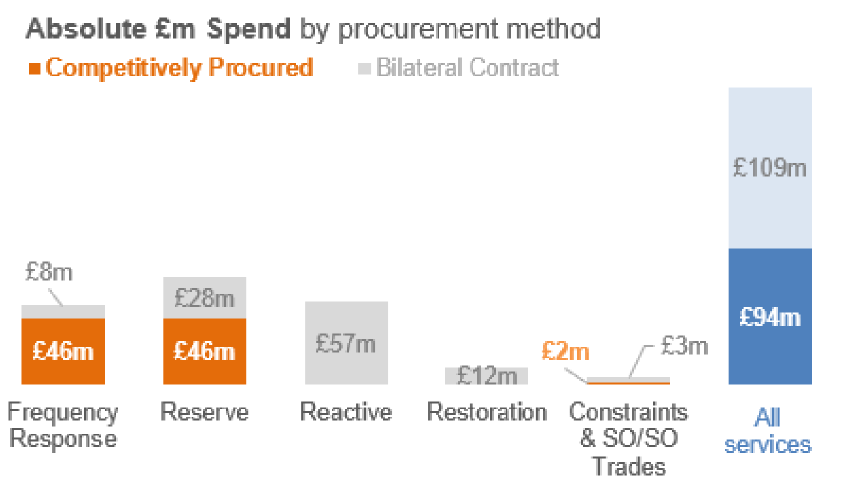


**Table 15: Percentage of services procured through competitive means by Quarter**

| Services | Q1 | Q2 | Q3 | Q4 | YTD |
|---|---|---|---|---|---|
| Frequency Response | 91% | 83% | 84% | | 86% |
| Reserve | 61% | 62% | 62% | | 62% |
| Reactive | 0% | 0% | 0% | | 0% |
| Restoration | 0% | 0% | 0% | | 0% |
| Constraints & SO/SO Trades | 89% | 376%[7] | 42% | | 132% |
| **All services** | **57%** | **61%** | **46%** | | **54%** |
| **Status (All services)** | ● | ● | ● | | ● |

## Performance benchmarks (Year 1)

- **Exceeding expectations:** >60%
- **Meeting expectations:** 50-60%
- **Below expectations:** <50%

## Supporting information

### Average Market Prices

| | Q1 | Q2 | Q3 | Q4 |
|---|---|---|---|---|
| Dynamic Containment (£/MW) | 17 | 17 | 9.1 | |
| Firm Frequency Response (FFR) Weekly Auction - Dynamic Low High (DLH) (£/MW) | 8.1 | 7.1 | 6.8 | |
| FFR Weekly Auction - Low Frequency Static (LFS) (£/MW) | 4.0 | 4.0 | 3.9 | |
| Optional Fast Reserve (£/MWh) | 102 | 123 | 280 | |
| Short Term Operating Reserve (STOR) Day ahead (£/MW) | 3.3 | 2.5 | 6.0 | |

### Frequency Response

As expected, competition in the Dynamic Containment (DC) market has continued to increase over the past quarter. There is now sufficient market depth for competition to start to reduce the cleared price to below the cap of £17/MW, with the average cleared price over the quarter being £9.1/MW. However, this increased competition has meant that some providers are moving between DC and FFR markets to maximise value and therefore we expect that average prices may increase next quarter. Bilateral costs for frequency response do not change due to the small number of contracts with fixed fees. Therefore increasing competition can show up as a reduction in the percentage of spend in competitively procured markets, as mentioned above.

[7] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data.

### Reserve

The average availability price for Short Term Operating Reserve (STOR) more than doubled in Q3 to £6.17/MWh, reflecting the sharp rise in wholesale electricity prices and the first incidences of acute system tightness since STOR day ahead procurement was launched. Nevertheless, with elevated prices and price volatility in the Balancing Mechanism, successfully securing sufficient reserve ahead of time became increasingly cost-effective throughout Q3, relative to securing the equivalent volume in real time. This can be seen as the total reserve spend is similar to the previous quarter despite the average price being higher.

### Reactive

We continue to develop our thinking around market-based procurement of reactive power and are working with a partner company to explore potential reactive market designs through an innovation project. We have not procured any market-based contracts for reactive support in Q3.

### Restoration

Contracts were awarded through open and competitive tenders for the South West and Midlands in 2020 and the Northern Region in early 2021, however the spend associated with them will be included in future reporting periods. We plan to launch a further competitive event in Q1 2022- 23 for services in the South-East region.

### Constraints & SO/SO Trades

Very little spend has been accrued on constraints and SO/SO trades this quarter, as shown in the chart above. This has led to a lower overall percentage of competitive spend, compared to previous quarters.

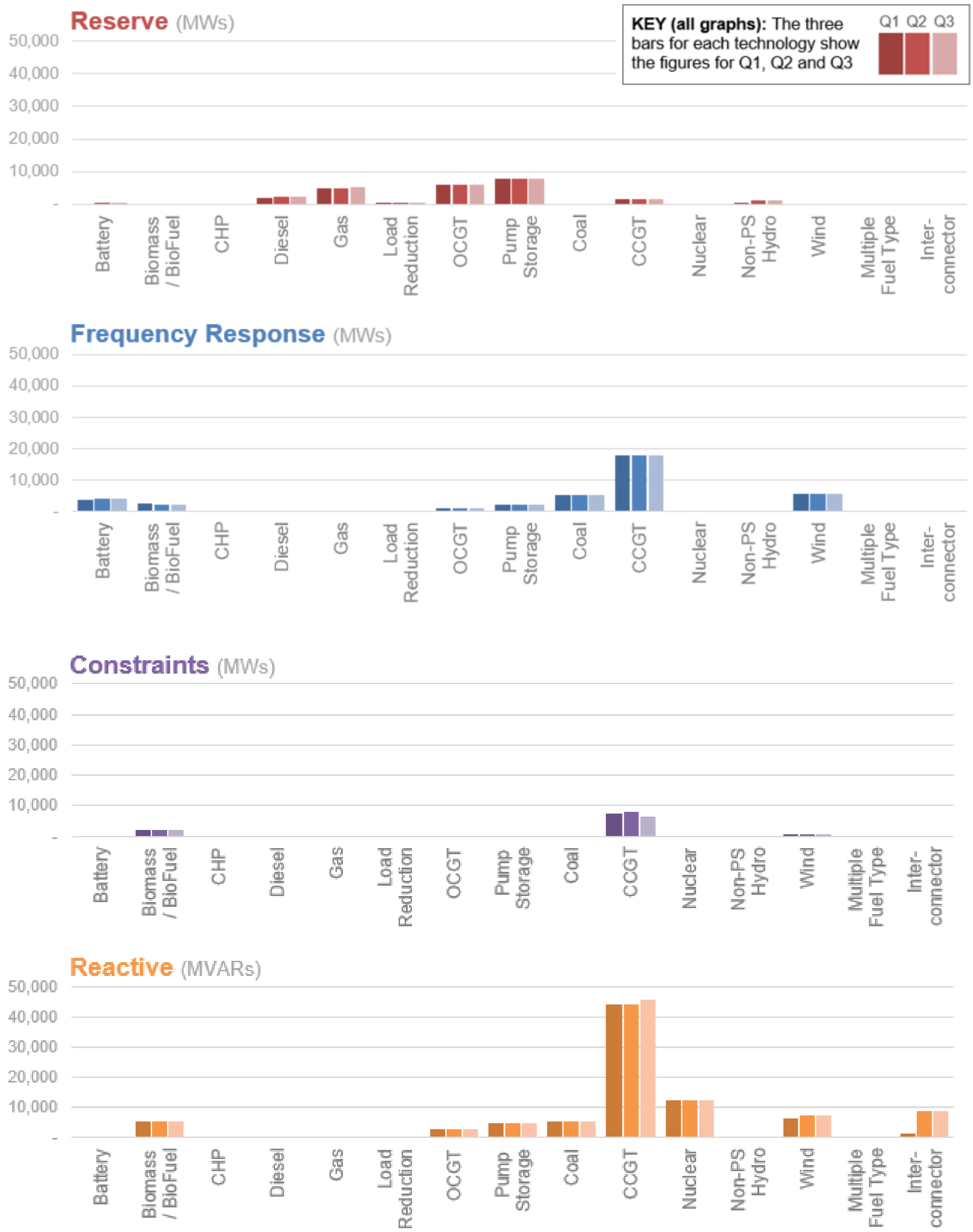
# RRE 2B Diversity of Service Providers

## Q3 2021-22 Performance

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

There are four services we report on below: Frequency Response (MFR, EFR, FFR, Dynamic Containment), Reserve (STOR, Fast Reserve), Reactive, Constraints. Data on Restoration services is not included in this report due to the sensitive nature of the information, which will be provided to Ofgem separately.

**Figure 11: Q3 total contracted volumes by service type**



## Table 16: Q3 monthly contracted volumes provided to the ESO by service type

### Reserve

| MWs | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Q1 | Q2 | Q3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | 7,788 | 7,786 | 7,786 | 8,000 | 8,000 | 8,001 | 8,045 | 8,049 | 8,049 | **23,360** | **24,001** | **24,143** |
| Battery | - | - | - | 20 | 20 | 20 | 28 | 23 | 23 | **-** | **60** | **74** |
| Biomass/BioFuel | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| CHP | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Diesel | 689 | 687 | 687 | 727 | 727 | 728 | 729 | 738 | 738 | **2,063** | **2,182** | **2,205** |
| Gas | 1,695 | 1,695 | 1,695 | 1,691 | 1,691 | 1,691 | 1,711 | 1,711 | 1,711 | **5,085** | **5,073** | **5,133** |
| Load Reduction | 72 | 72 | 72 | 50 | 50 | 50 | 65 | 65 | 65 | **216** | **150** | **195** |
| OCGT | 2,061 | 2,061 | 2,061 | 2,061 | 2,061 | 2,061 | 2,061 | 2,061 | 2,061 | **6,183** | **6,183** | **6,183** |
| Pump Storage | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | 2,600 | **7,800** | **7,800** | **7,800** |
| Coal | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| CCGT | 479 | 479 | 479 | 479 | 479 | 479 | 479 | 479 | 479 | **1,437** | **1,437** | **1,437** |
| Nuclear | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Non-PS Hydro | 192 | 192 | 192 | 372 | 372 | 372 | 372 | 372 | 372 | **576** | **1,116** | **1,116** |
| Wind | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Multiple Fuel Type | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Interconnector | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |

### Frequency Response

| MWs | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Q1 | Q2 | Q3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | 13,146 | 12,808 | 13,047 | 13,195 | 13,013 | 13,088 | 13,232 | 12,780 | 13,331 | **39,001** | **39,296** | **39,343** |
| Battery | 1,360 | 1,038 | 1,246 | 1,390 | 1,258 | 1,331 | 1,475 | 1,033 | 1,618 | **3,644** | **3,979** | **4,126** |
| Biomass/BioFuel | 785 | 785 | 805 | 825 | 757 | 737 | 737 | 737 | 717 | **2,375** | **2,319** | **2,191** |
| CHP | - | - | - | - | - | - | - | - | - | - | - | - |
| Diesel | 44 | 44 | 42 | 24 | 42 | 64 | 64 | 64 | 64 | **130** | **130** | **192** |
| Gas | - | - | - | - | - | - | - | - | - | - | - | - |
| Load Reduction | - | - | - | - | - | - | - | - | - | - | - | - |
| OCGT | 373 | 373 | 373 | 373 | 373 | 373 | 373 | 373 | 373 | **1,119** | **1,119** | **1,119** |
| Pump Storage | 728 | 728 | 728 | 728 | 728 | 728 | 728 | 728 | 728 | **2,184** | **2,184** | **2,184** |
| Coal | 1,782 | 1,782 | 1,782 | 1,782 | 1,782 | 1,782 | 1,782 | 1,782 | 1,782 | **5,346** | **5,346** | **5,346** |
| CCGT | 5,999 | 5,999 | 5,999 | 5,999 | 5,999 | 5,999 | 5,999 | 5,999 | 5,999 | **17,997** | **17,997** | **17,997** |
| Nuclear | 92 | 92 | 92 | 92 | 92 | 92 | 92 | 92 | 92 | **276** | **276** | **276** |
| Non-PS Hydro | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | 70 | **210** | **210** | **210** |
| Wind | 1,881 | 1,881 | 1,881 | 1,881 | 1,881 | 1,881 | 1,881 | 1,881 | 1,855 | **5,643** | **5,643** | **5,617** |
| Multiple Fuel Type | 32 | 16 | 29 | 31 | 31 | 31 | 31 | 21 | 33 | **77** | **93** | **85** |
| Interconnector | - | - | - | - | - | - | - | - | - | - | - | - |

### Constraints

| MWs | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Q1 | Q2 | Q3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | 3,123 | 3,123 | 3,253 | 3,448 | 3,650 | 2,765 | 2,685 | 2,685 | 2,685 | **9,499** | **9,863** | **8,055** |
| Battery | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Biomass/BioFuel | 595 | 595 | 595 | 595 | 595 | 595 | 595 | 595 | 595 | **1,785** | **1,785** | **1,785** |
| CHP | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Diesel | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Gas | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Load Reduction | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| OCGT | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Pump Storage | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Coal | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| CCGT | 2,505 | 2,505 | 2,635 | 2,845 | 3,055 | 2,170 | 2,075 | 2,075 | 2,075 | **7,645** | **8,070** | **6,225** |
| Nuclear | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Non-PS Hydro | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Wind | 23 | 23 | 23 | 8 | - | - | 15 | 15 | 15 | **69** | **8** | **45** |
| Multiple Fuel Type | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |
| Interconnector | - | - | - | - | - | - | - | - | - | **-** | **-** | **-** |

## Reactive

| MVARs | Apr-21 | May-21 | Jun-21 | Jul-21 | Aug-21 | Sep-21 | Oct-21 | Nov-21 | Dec-21 | Q1 | Q2 | Q3 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Total** | 27,889 | 27,889 | 27,889 | 30,534 | 30,534 | 30,534 | 30,534 | 30,534 | 31,870 | **83,667** | **91,602** | **92,938** |
| Battery | - | - | - | - | - | - | - | - | - | - | - | - |
| Biomass / BioFuel | 1,734 | 1,734 | 1,734 | 1,734 | 1,734 | 1,734 | 1,734 | 1,734 | 1,734 | **5,202** | **5,202** | **5,202** |
| CHP | - | - | - | - | - | - | - | - | - | - | - | - |
| Diesel | - | - | - | - | - | - | - | - | - | - | - | - |
| Gas | - | - | - | - | - | - | - | - | - | - | - | - |
| Load Reduction | - | - | - | - | - | - | - | - | - | - | - | - |
| OCGT | 967 | 967 | 967 | 967 | 967 | 967 | 967 | 967 | 967 | **2,901** | **2,901** | **2,901** |
| Pump Storage | 1,630 | 1,630 | 1,630 | 1,630 | 1,630 | 1,630 | 1,630 | 1,630 | 1,630 | **4,890** | **4,890** | **4,890** |
| Coal | 1,731 | 1,731 | 1,731 | 1,731 | 1,731 | 1,731 | 1,731 | 1,731 | 1,731 | **5,193** | **5,193** | **5,193** |
| CCGT | 14,832 | 14,832 | 14,832 | 14,832 | 14,832 | 14,832 | 14,832 | 14,832 | 16,156 | **44,496** | **44,496** | **45,820** |
| Nuclear | 4,095 | 4,095 | 4,095 | 4,095 | 4,095 | 4,095 | 4,095 | 4,095 | 4,095 | **12,285** | **12,285** | **12,285** |
| Non-PS Hydro | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | 189 | **567** | **567** | **567** |
| Wind | 2,192 | 2,192 | 2,192 | 2,437 | 2,437 | 2,437 | 2,437 | 2,437 | 2,449 | **6,576** | **7,311** | **7,323** |
| Multiple Fuel Type | - | - | - | - | - | - | - | - | - | - | - | - |
| Interconnector | 519 | 519 | 519 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | 2,919 | **1,557** | **8,757** | **8,757** |

## Supporting information

### Reserve

We continue to procure both Short Term Operating Reserve (STOR) and Fast Reserve as we develop a new suite of reserve products under our reserve reform programme. The STOR service has been procured at day ahead via a daily auction since April 2021 with around 40 units regularly bidding in to secure a share of the ~ 1300MW daily requirement for STOR. Due to the technical requirements (response time/delivery duration) the service continues to be delivered by the more traditional Diesel, Gas and Coal fuels. For Fast Reserve, we currently procure an optional service where a small number of (prequalified) more traditional technologies contract on the day to make their capacity available.

With the forthcoming reserve products coming online through 2022, initially with Negative Slow Reserve (downward service) and Positive Slow Reserve (upward service), we would expect to see new technologies and smaller plant entering the market. For the Negative Slow product, these new providers will include smaller renewable providers as well as those that had previously offered the Optional Downward Flexibility Management (ODFM) service, whilst we expect to retain the existing STOR players as well as attracting new technologies for the Positive Slow product. As the new products are introduced through 2022, we will continue to procure STOR and Optional Fast Reserve in parallel.

### Frequency Response

Frequency Response continued to be procured through the monthly competitive Firm Frequency Response (FFR) tenders and the daily Dynamic Containment (DC) day ahead auctions. Q3 saw the move to the Electricity Forward Agreement (EFA) Block procurement of both High and Low DC response. This move to EFA block procurement corresponded with the move away from the introductory flat buy order, to shaped buy orders. This has allowed a fluid movement of providers tendering and being contracted for their units across the two services. DC has grown to 60+ units registered, totalling 1,000+MW that can bid into the daily auctions. Frequency Response has seen the continued growth of these services being delivered through battery storage assets.

During Q3 the ESO has continued to develop the two new frequency products of Dynamic Moderation (DM) and Dynamic Regulation (DR) with corresponding industry consultations closing in December 2021. With the DM and DR products going live in 2022 we will cease to procure the Monthly tendered FFR service. We would expect to see providers that had previously tendered into the FFR tender moving to the new services.

The Dynamic Low High and Low Frequency Static weekly auctions ceased in November after the 2 year trial period finished. The success and learning of the auction trial enabled the new suite of Frequency services to use the auction platform for the daily auctions.

### Constraints

Constraint costs are when the ESO pays generators to constrain their output due to network capacity limitations and typically for them to increase or decrease MWs on the system. Historically, this service has been limited to the providers that are connected to the transmission network. Once the Constraint Management Pathfinder goes live, this will potentially increase the number of technology types providing this service in 2022.

### Reactive

The reactive power service is delivered primarily by providers who have Mandatory Service Agreements and are typically connected to the Transmission Network. These providers would also be in the Balancing Mechanism (BM). The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. We expect contracts with more diverse technologies to be put in place in 2022.

## RRE 2E Accuracy of Forecasts for Charge Setting

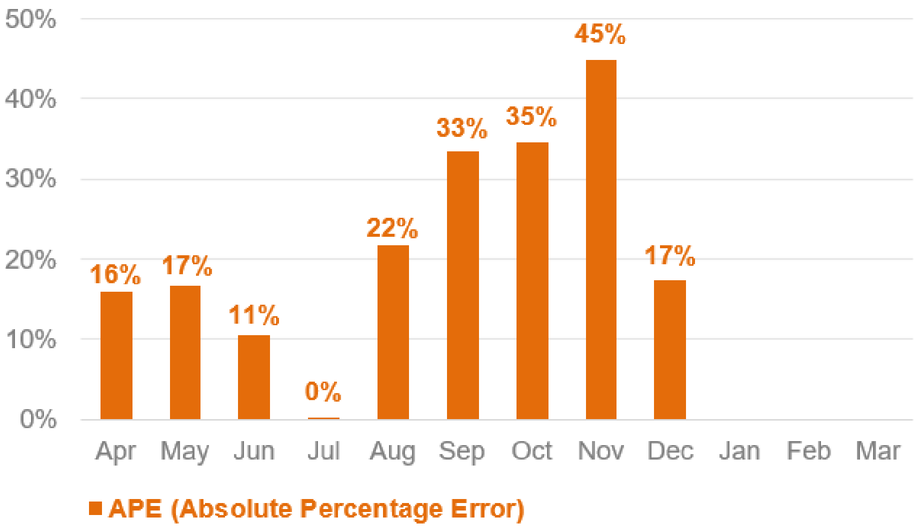
### Q3 2021-22 Performance

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.

**Table 17: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance**

| | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | Jan | Feb | Mar |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Actual | 3.8 | 4.5 | 4.6 | 4.2 | 5.8 | 7.1 | 8.4 | 12.5 | 7.5 | | | |
| Month-ahead forecast | 3.2 | 3.7 | 4.1 | 4.2 | 4.5 | 4.7 | 5.5 | 6.9 | 6.2 | | | |
| **APE (Absolute Percentage Error)[8]** | **16%** | **17%** | **11%** | **0%** | **22%** | **33%** | **35%** | **45%** | **17%** | | | |

**Figure 12: Monthly BSUoS forecasting performance (Absolute Percentage Error)**




### Supporting information

Outturn BSUoS for December was lower than the previous month but remained high. Continued high Balancing Mechanism prices impacted significantly on the costs of actions taken to operate the system.

Accuracy of the forecast over the quarter has been relatively low, however, the percentage error for December was significantly lower than the preceding two months.

Work on revising the BSUoS forecasting methodology and also incorporating a revised view of constraint costs is ongoing. This will provide more accurate forecasting for BSUoS cost scenarios.

[8] 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.

## Notable events during Q3

### GC0137 Minimum specification for equipment providing grid-forming capability

This modification proposes to add a non-mandatory technical specification to the Grid Code, relating to what is referred to as Virtual Synchronous Machine ("VSM") or Grid Forming capability. This specification will enable applicable parties (primarily those utilising power electronic converter technologies (wind farms, HVDC interconnectors, and solar parks) to offer an additional grid stability service which will enable their participation in a commercial market-based system to provide this support. At the end of an involved development process the final report for this modification was submitted to Ofgem for a decision following approval at the October 2021 meeting of the Grid Code Panel. The specification will allow participation in future pathfinders to provide stability products and is a key step to net zero. It is a world first as the UK is the first country to have set specifications for this and ENTSO-E are using it as an input for their work. An industry expert group has also been formed to produce more detailed guidance on the requirements and to aid effective participation.

### Autumn Markets Forum

On 18 November we held our Autumn Markets Forum[9]. This was a one day interactive event providing an update of how the ESO is developing new and existing markets to enable the transition to net zero. The following topics were covered:

- Markets Roadmap - What next?
  - Over 125 attendees joined to hear ESO provide updates on its Markets Roadmap, Response and Reserve reform activities, and stability market design
- Net Zero Market Reform
  - Over 120 attendees joined to discuss the publication of Phase 2 of ESO's Net Zero Market Reform programme, covering the case for change as well as our proposed framework for assessing reform options in Phase 3
- Energy Code Review
  - Over 80 attendees joined to hear about the BEIS / Ofgem Energy Code Reform work as well as the ESO's thinking after the recent consultation

### Net Zero Market Reform update published

On 18 November, we also published an update on our Net Zero Market Reform project, which is exploring how GB electricity markets could be redesigned to support a carbon-free electricity system by 2035, and a net zero economy by 2050, at lowest cost. Following completion of Phase 1 (scoping and stakeholder landscape) in March 2021, the latest update presents our conclusions from Phase 2 (case for change and identification of options). It draws together the results of modelling analysis with insights from ESO experts and external stakeholders. We identify the key challenges for markets to address on the road to net zero, set out our framework for assessing the different market design alternatives, and present the list of options we are taking forward for detailed consideration in our next phase of work. The full update can be found here.

In the first two weeks following publication, the update was downloaded more than 350 times. It has also generated a lot of interest from across the industry with many individuals, organisations and trade associations requesting time to discuss the update further and being keen to get more involved in the Net Zero Market Reform project going forward. Engagement will continue into Q4 2021-22 and we have our next series of Net Zero Market Reform events on 17 and 18 January where will be hosting two detailed events.

## Code Administrator Workshop

As part of our Code Administrator deliverables plan[10] for 2021-22, we promised to set up workshops throughout the year to collaborate and co-create with stakeholders. We held a Code Administrator Workshop[11] on 6 December.

This session was aimed at people who already have some involvement or understanding of the code change process. For completely new attendees, we were open to helping them understand what we do and how we might be able to help.

During the session the following was covered:

- Who we are and what each of us lead on
- Shared recent Customer feedback and provided an update on our Code Administrator Deliverables Plan
- Updated Code Modification Tracker - an overview of the co-creation work so far and seeking further feedback
- Chairing of Workgroups - what we have learned so far and how we are building our capability as a team
- An opportunity to ask any questions

We asked participants how likely they were to recommend the event to a friend or colleague - this received an average satisfaction score of 8.83.

We plan to run further workshops in 2022 and continue to co-create with stakeholders to make incremental changes to align with the future of Energy Code Reform.

## Dynamic Moderation and Dynamic Regulation Consultation

Following the closure of the EBR Article 18 Consultation for Dynamic Moderation (DM) and Dynamic Regulation (DR) on 15 December 2021, we have submitted consultation responses and proposed changes to Ofgem. DM and DR are both pre-fault services, which form part of our new faster-acting frequency response products alongside Dynamic Containment. DM provides rapid response to keep frequency within operational limits whereas DR is designed to slowly correct continuous but small deviations in frequency with the aim to continually regulate frequency around the target of 50Hz.

To ensure providers are aware of the changes in plenty of time ahead of the launch, we have provided a summary document on our website[12]. We are hosting a webinar on 25 January to discuss the consultation changes and the next steps for onboarding.

We have published the Testing Analysis Tool and user guide for both DM[13] and DR[14]. These documents complete the suite of testing documentation. We have also shared technical IT details for both BM and non-BM providers. During the consultation we published an FAQ[15] document including questions from providers and webinars, which we will continue to update.

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9 https://www.nationalgrideso.com/research-publications/markets-forum-roadmap-2025/events
10 https://www.nationalgrideso.com/document/191576/download
11 https://subscribers.nationalgrid.co.uk/t/ViewEmail/d/595A823D365305932540EF23F30FEDED/72523BCBCC00A969B3138EAD4DECE712?alternativeLink=False
12 https://www.nationalgrideso.com/document/230406/download
13 https://www.nationalgrideso.com/industry-information/balancing-services/Frequency-Response-Services/Dynamic-Moderation/Document-library
14 https://www.nationalgrideso.com/industry-information/balancing-services/Frequency-Response-Services/Dynamic-Regulation/Document-library
15 https://subscribers.nationalgrid.co.uk/t/d-l-aditkdk-tdechuhl-y/

## Contracts for Difference

The Contracts for Difference (CfD)[16] fourth and biggest round – which aims to secure 12GW of electricity capacity – opened on 13 December; with £285m per annum funding available for low-carbon technology. This round is open to an expanded number of renewable energy technologies; with offshore wind, onshore wind, solar, tidal, and floating offshore wind all eligible to bid.

The Delivery Body has produced a comprehensive support package[17] for the Industry; including guidance materials, webinars/ pre-recorded videos and email/ phone support in order to enable efficient and effective management of both new and existing applicant journeys. We've also advised on and implemented all the policy changes made by BEIS into our IT systems and have been reviewing and updating internal processes accordingly. As well as being responsible for managing and operating the front end of the process, including assessing the eligibility of applications, the Delivery Body will also run the actual allocation/ auction process if required.

## Distributed Restart

On 20 December we published three reports:

- Distribution Restoration Future Commercial Structure and Industry Codes Recommendations[18]
    - This final report from the Procurement and Compliance workstream covers the full end to end procurement process and the drafting of the industry codes needed to future proof the designs.
- Demonstration of Black Start from DERs (Live Trials Report) Part 1[19]
    - The primary focus of this report (part 1) is to provide an overview of the three live trial sites, (Galloway, Chapelcross and Redhouse), the technical issues faced and the learnings obtained.
- Project Progress Final Report[20]
    - This report provides an annual progress review for Distributed ReStart which shows the project has continued to deliver its outcomes on time and under budget.

## Early consultation for C16 changes

The ESO is required to establish statements and guidelines (regarding procurement of balancing services, etc) within specified timescales, in accordance with special condition C16 within the transmission licence.

We compiled and shared our early thoughts with stakeholders during a workshop[21] in November 2021 followed by a release of an informal early consultation[22] with stakeholder responses due in December 2021.

We were keen to create more opportunities for interested stakeholders to discuss any changes that they would like to be proposed ahead of the annual review. We wish to build clarity on the changes recommended, and to gain feedback on stakeholder priorities. Stakeholders were encouraged to challenge or support the topics discussed. These type of engagement events have created an important source of information for this year's review. Stakeholders have thanked us for sharing our early thoughts on changes to our products and services, and provided positive feedback on the clarity of our communication.

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[16] https://www.cfdallocationround.uk/
[17] https://www.emrdeliverybody.com/CfD/Round-4.aspx
[18] https://www.nationalgrideso.com/document/226916/download
[19] https://www.nationalgrideso.com/document/226951/download
[20] https://www.nationalgrideso.com/document/226946/download
[21] https://www.nationalgrideso.com/document/221016/download
[22] https://www.nationalgrideso.com/document/221066/download

Feedback from previous years (November 2020) has highlighted the need for the ESO to provide further clarity on specific products and implementation plans. Previously, we have received lots of detailed comments and suggestions for areas of further review. In November - December 2021, we have looked to address these areas and/or to provide a plan showing how these areas will be addressed over time. Through earlier and continued engagement, stakeholders' queries have been reduced and concerns addressed earlier.

# Role 3 System insight, planning and network development

Please note there are no monthly or quarterly metrics or RREs for Role 3.

## Notable events during Q3

### Bridging the Gap 2022 – Peaks and Troughs

Our third Bridging the Gap to Net Zero report builds on our 2021 peaks and troughs focus. Over the past three months we have been discussing with stakeholders the challenges of dealing with the dynamic peaks and troughs resulting from a low carbon energy system. We've identified a series of milestones and actions, which need to happen over the next ten years to make sure we are able to meet the 2035 zero carbon electricity system target in a cost effective way. We are now in the process of defining the key messages and writing up our findings in time for publication and a launch webinar in March.

### Autumn Offshore Coordination progress publication

On 18 October 2021, we released our Autumn Offshore Coordination progress publication[23], providing a consolidated view of the latest activities across the ESO Offshore Coordination project, explaining how these activities align with the wider Offshore Transmission Network Review (OTNR), and signposting upcoming project milestones and opportunities to engage.

Following this, on 21 October, we hosted two industry webinars, one specifically for offshore developers, to provide an update on project progress and signpost next steps and opportunities to inform future work; and a project-wide progress webinar where the Offshore Coordination project team discussed progress since the start of the year and provided an opportunity for all other market participants to ask questions. Across both webinars we had more than 300 attendees and over 60 questions were raised and answered.

We have now appointed two stakeholder engagement agencies (Grayling and PublicFirst), to provide support with developing the strategy for the engagement of the other public stakeholders. Public First have subsequently conducted opinion polling and focus groups with residents of coastal regions, to garner insights into public views on climate change, renewable generation, and associated infrastructure, and to inform future messaging for community engagement representatives and for wider stakeholder engagement.

Within the OTNR Pathway to 2030 workstream, we extended the application of Central Design Group (CDG) Terms of Reference (ToR) to all subgroups. We have now implemented and gained sign off for the ToR for all the CDG Subgroups; The CDG has also signed off the options and environmental assessment methodology.

In collaboration with the TOs we have revised and gained sign off for the revised Holistic Network Design (HND) delivery plan, with delivery planned by the end of June 2022. The new HND timeline with a summary of the content of the associated HND publication package which will be published on the ESO website.

To provide independent assurance of the HND, we have appointed Atkins, whose assurance review of the HND has now commenced. A further consultancy agency, Guidehouse, has been appointed and successfully delivered their first report, to assess whether the proposed HND and its associated publication package fulfils the requirements of the CDG ToR.

At the end of October, in line with our commitments under the OTNR Early Opportunities workstream, we provided a detailed update to Ofgem and BEIS on progress to date on benefits of projects that have opted in for coordination opportunities, assessment of the barriers to delivery of the different coordination models, and initial thoughts on required codes and standard changes. We

[23] https://www.nationalgrideso.com/document/214981/download

have also subsequently delivered code and standard workshops on the Connection and Use of System Code (CUSC) (especially Section 14 and Section 15), Grid Code, SO-TO Code (STC) and Security and Quality of Supply Standard (SQSS), with positive feedback received from the 25-plus developers and wider industry attendees.

Throughout this period, we have also submitted and published on the ESO website[24] our response to the BEIS Enduring Regime (ER) consultation and the BEIS Energy National Policy Statement consultation. We have also strongly supported OTNR's ER policy development and the sub-groups across the ER policy areas. Likewise, all ESO workstream teams have supported and informed the review of the OTNR delivery plan prior to its re-baselining.

**Launch of Stability Pathfinder Phase 2 commercial tender**

The commercial submission window for NOA Stability Pathfinder Phase 2 opened to the industry on 9 November 2021. Phase 2 is seeking to procure additional volumes of inertia, short circuit level and fast acting dynamic voltage support across Scotland between 2024 and 2034. This is due to the increase in asynchronous generation such as wind and solar and the closure of existing synchronous units in Scotland.

The tender stage is the final step in the Phase 2 process following the completion of the Expression of Interest and Feasibility Study stages in previous quarter in 2021. These previous steps allowed interested participants to submit and demonstrate the capability of their proposals, and also allowed them to provide their feedback into tendering requirement documents.

The submission window closed on 14 January 2022. The ESO will carry out an assessment to select the economic combination of solutions to meet the Stability requirement. Successful tenderers will be awarded contracts in early March 2022 to deliver the solutions from as early as September 2022.

[24] https://www.nationalgrideso.com/future-energy/projects/offshore-coordination-project/project-documents