nationalgridESO

ESO RIIO-2 Business Plan

November Monthly Incentives Report

23 December 2021

Contents

Introduction

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

The ESO's Delivery Schedule sets out in more detail what the ESO will deliver, along with associated milestones and outputs, for the "Business Plan 1" period, which runs from 1 April 2021 to 31 March 2023.

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

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

Every quarter, we report on a larger set of performance measures, and also provide an update on our progress against our Delivery Schedule in the RIIO-2 deliverables tracker.

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

Please see our website for more information.

Summary

In November 2021 we have successfully delivered the following notable events and publications:

- Review of the balancing market announced
- Virtual Energy System launched at COP26
- Changes to the Balancing Mechanism successfully implemented under Release R0
- New dataset (2-14 days ahead demand forecast) introduced by the Energy Forecasting team on the ESO Data Portal, giving data at an improved resolution
- The Autumn Markets Forum was held on Thursday 18 November and an update on Net Zero Market Reform was published on the same day
- Changes to Short Term Operating Reserve (STOR) terms and conditions were approved by Ofgem
- Carbon Intensity Dashboard launched
- Electricity Ten Year Statement (ETYS) 2021 published
- Revised timeline communicated for NOA Stability Pathfinder Phase 3
- Stability Pathfinder Phase 2 commercial tender launched

The table below summarises our Metrics and Regularly Reported Evidence (RRE) performance for November 2021:

Table 1: Summary of Metrics and Regularly Reported Evidence

Metric/Regularly Reported Evidence		Performance	Status
Metric 1A	**Balancing Costs**	£541m vs benchmark of £123m	🔴
Metric 1B	**Demand Forecasting**	Forecasting error of 1.8% (vs benchmark of 1.8%)	🟢 (light green)
Metric 1C	**Wind Generation Forecasting**	Forecasting error of 4.5% (vs benchmark of 5.3%)	🟢
Metric 1D	**Short Notice Changes to Planned Outages**	3.1 delays or cancellations per 1000 outages due to an ESO process failure (vs benchmark of 1 to 2.5).	🔴
RRE 1E	**Transparency of Operational Decision Making**	99.7% of actions have reason groups allocated	N/A
RRE 1G	**Carbon intensity of ESO actions**	9.4gCO2/kWh of actions taken by the ESO	N/A
RRE 1I	**Security of Supply**	0 instances where frequency was more than ±0.3Hz away from 50Hz for more than 60 seconds, 0 voltage excursions	N/A
RRE 1J	**CNI Outages**	1 planned system outage	N/A
RRE 2E	**Accuracy of Forecasts for Charge Setting**	Month ahead BSUoS forecasting accuracy (absolute percentage error) of 45%	N/A

Below expectations 🔴 **Meeting expectations** 🟢 (light green) **Exceeding expectations** 🟢

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

Gareth Davies
ESO Regulation Senior Manager

Role 1 Control Centre operations

Metric 1A Balancing cost management

November 2021 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.

1. 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'.
2. 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'.
3. 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.).
4. 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

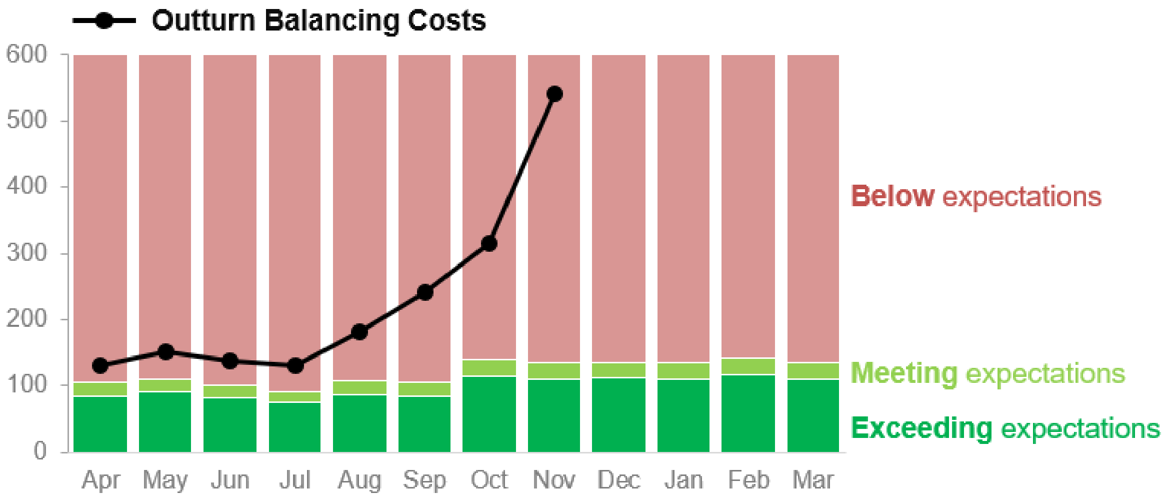


Table 2: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	YTD
Benchmark: non-constraint costs (A)	41.3	41.3	41.3	41.3	41.3	41.3	41.3	41.3	330.6
Indicative benchmark: constraint costs (B)	59.9	50.6	52.3	49.2	58.4	66.9	76.3	75.0	488.4
Indicative benchmark: total costs (C=A+B)	101.2	91.9	93.6	90.5	99.7	108.2	117.6	116.3	819.0
Outturn wind (TWh)	2.8	3.2	2.5	1.9	3.0	2.8	5.5	5.1	26.7
Ex-post benchmark: constraint costs (D)	53.5	58.9	49.9	42.5	55.7	53.4	86.6	81.8	482.4
Ex-post benchmark (A+D)	**94.8**	**100.3**	**91.2**	**83.8**	**97.1**	**94.8**	**128.0**	**123.1**	**813.0**
Outturn balancing costs[1]	**130.0**	**151.7**	**137.8**	**130.9**	**182.4**	**240.3**	**315.6**	**541.2**	**1829.8**
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

The balancing costs for November were £541.2m, which is £225.5m higher than October, and in the 'Below Expectations' range.

November's balancing cost spend is the highest on record. During the month we have seen 23 days where the daily balancing costs exceeded £10m and 10 of these where the cost was over £20m. Whilst both constraint and non-constraint costs have increased from the previous month, more than two thirds of the spend has been on constraint related actions.

The significant increase in constraint costs is 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. We have seen several very high-cost days in the BM in recent weeks and as a result are undertaking a review of the balancing market. We are also working with Ofgem to consider options for revising the benchmark for this metric.

Breakdown of costs vs previous month

Balancing Costs variance (£m): November 2021 vs October 2021

		(a) Oct-21	(b) Nov-21	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	10.2	11.1	0.8	
	Operating Reserve	58.5	72.5	14.0	
	STOR	4.1	8.7	4.6	
	Negative Reserve	3.4	2.3	(1.1)	
	Fast Reserve	17.4	24.0	6.6	
	Response	41.1	26.2	(14.8)	
	Other Reserve	1.9	2.3	0.4	
	Reactive	13.4	17.4	4.0	
	Black Start	3.0	5.1	2.1	
	Minor Components	9.0	10.0	1.0	
Constraint Costs	Constraints - E&W	30.6	41.6	11.1	
	Constraints - Cheviot	11.0	12.3	1.3	
	Constraints - Scotland	38.1	126.4	88.3	
	Constraints - Ancillary	6.5	3.1	(3.5)	
	ROCOF	19.3	6.9	(12.4)	
	Constraints Sterilised HR	48.2	171.2	123.0	
Totals	Non-Constraint Costs - TOTAL	161.9	179.7	17.7	
	Constraint Costs - TOTAL	153.7	361.5	207.8	
	Total Balancing Costs	**315.6**	**541.2**	**225.5**	

As shown in the total rows above, the majority of this month's significant increase in costs came in constraint costs which increased by £207.8m, with non-constraints costs increasing by £17.7m.

Against the Constraint category, the breakdown shows that Constraints - Scotland and Constraint Sterilized Headroom (HR) were the two categories with the largest increase from October. A decrease in monthly cost was seen across the following categories: Response, Negative Reserve, Constraints - Ancillary and RoCoF.

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

- **Constrained Sterilised Headroom: £123m increase.** This increase in constrained sterilised headroom is a cost associated with constraints. This significant increase is a result of reduced boundary capability (due to system outages), high wind levels and a resultant need to increase the generation constrained off behind a constraint. Headroom that was available on the constrained generation needs to be replaced through actions in the BM – which are high cost actions.

- **Constraint – Scotland: £88.3m increase**. Throughout the month constraints actions were needed due to prevalent windy weather that required us to take a large volume of BM actions to reduce generation to manage thermal constraints. The most expensive days for this category were Tuesday 23 November and Wednesday 24 November with a daily spend of around £30m and £50m respectively.

- **Operating Reserve: £14m increase**. Nearly 60% of the monthly spend for this category was incurred on Tuesday 2 November when repositioning of plants required additional units to be instructed in time for the darkness peak. Offers of up to £4050/MWh were accepted to meet the operational margin requirements, generating a daily spend of nearly £42m.

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.

Overall November balancing costs are higher this year than for the same period last year. Constraint costs significantly exceed the previous year, due to the cost of actions required to manage the constraints. Non-constraint costs have been consistently higher than previous years across, due to tight system margins and high gas prices, and have increased from October 2021 costs.

Constraint Costs

Compared with the same period last year:

Constraint costs have outturned 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 cost in all constraint categories – including the cost of replacement energy and headroom associated with particular constraints.

Compared with the previous month:

Constraint costs were higher than in October due to:

- Low boundary availability which required BM actions (which are expensive) to constrain off generation and replace energy & headroom elsewhere

Non-Constraint Costs

Compared with the same period last year:

Non-constraint costs remain significantly higher this year than 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.

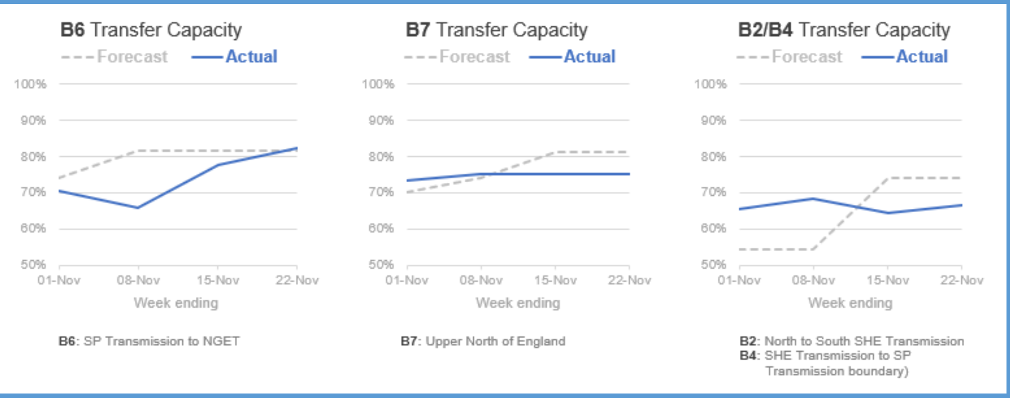
- Response costs remain higher than in 2020 due to the introduction of the Dynamic Containment service, and the amended requirement for response holding. This has meant a higher volume of response has been procured, and at a higher price than in 2020.

Compared with the previous month:

Non-constraint costs were higher than in October due to:

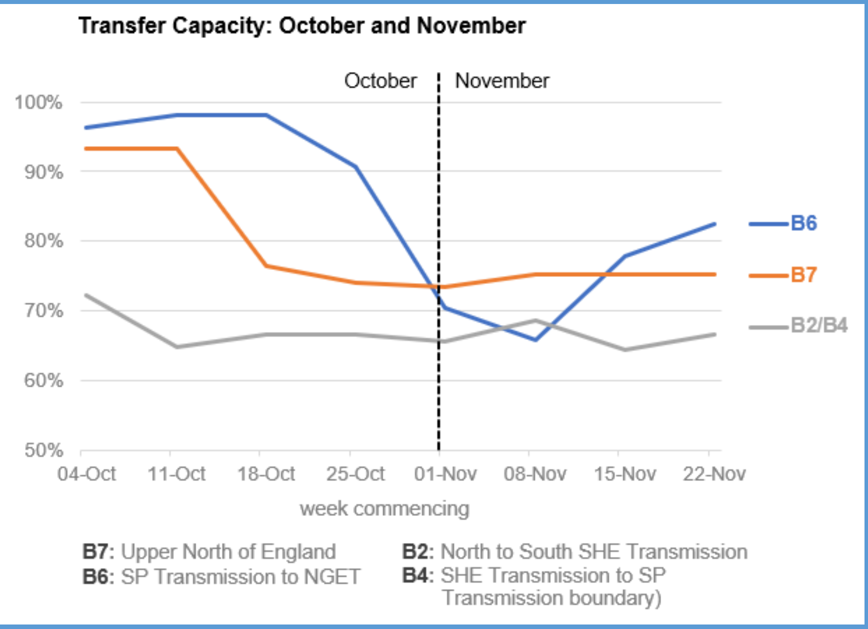
- Increased costs in Operating Reserve due to high BM prices being submitted by units which are required for system operation.

Network availability



Transfer capacity has been lower than forecast for the majority of this month which, combined with windy conditions has led to the need for actions to manage these constraints.

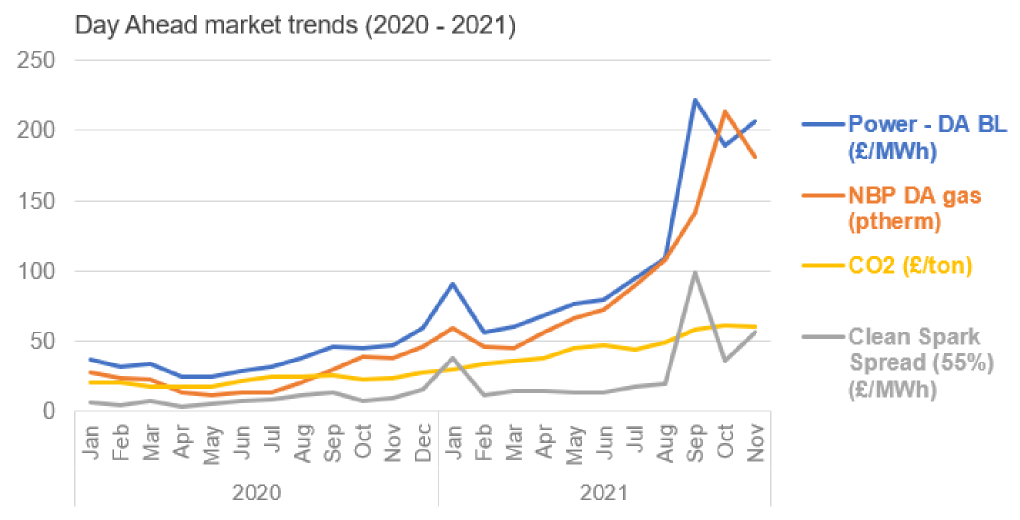
As shown below, boundary capacity has been significantly lower than the previous month. Therefore, given the weather conditions, higher constraint costs would be expected.



The cost of these actions is shown in the high ‘Constraints – Scotland’ and Constrained Sterilised Headroom costs for this month. These actions, required to manage the constraint, are taken within the BM and are subject to the higher BM prices discussed earlier.

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

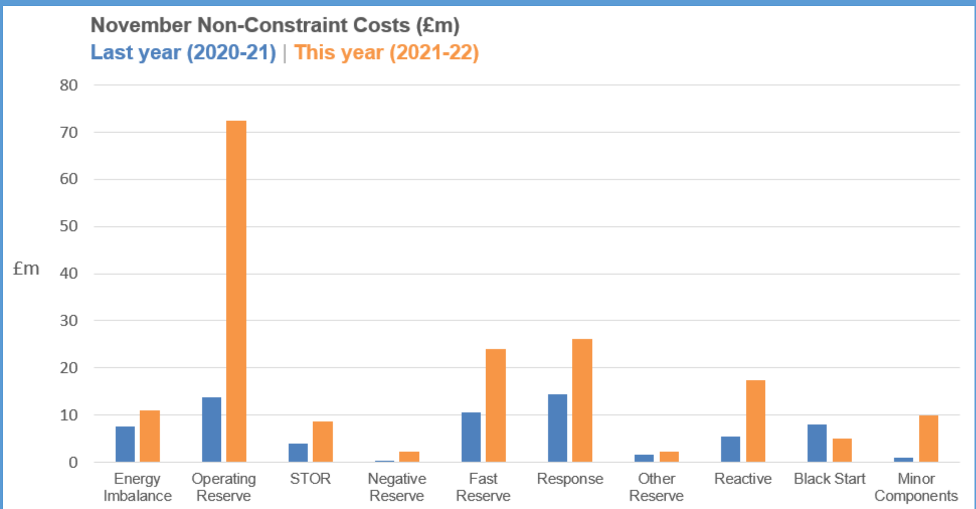


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices have increased from October and remain high compared to the previous year. The day ahead gas prices have fallen slightly from October but again, remain 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

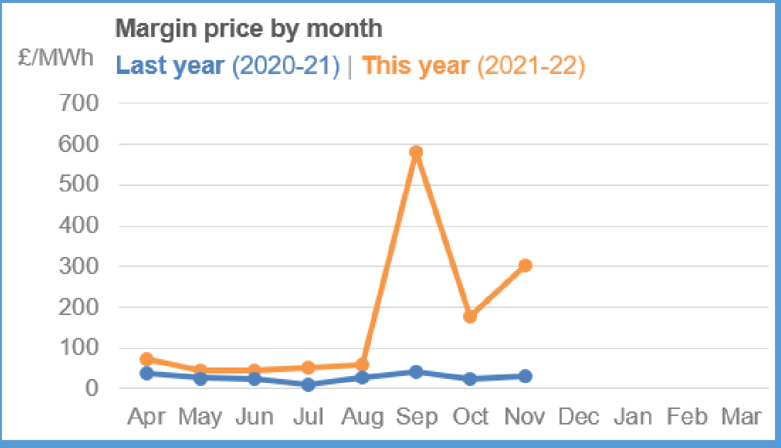


Comparing this year's November energy costs with those of November last year we can see that there has been a rise in all categories, except Black Start.

- **Operating Reserve** costs have increased by nearly £59m, 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 nearly £14m due to the higher market prices impacting on BM actions available to ESO.
- **Response** costs have increased by nearly £12m. With the introduction of the Dynamic Containment service, this continues to be higher spend than the previous year.

- **Reactive costs** have increased by £12m. As the volume of actions taken is in line with seasonal norms, this 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 increased since October and remain high when compared to last year. This is due to the increased number of actions taken to make more generation available to meet our operational margin requirements.

Daily costs trends

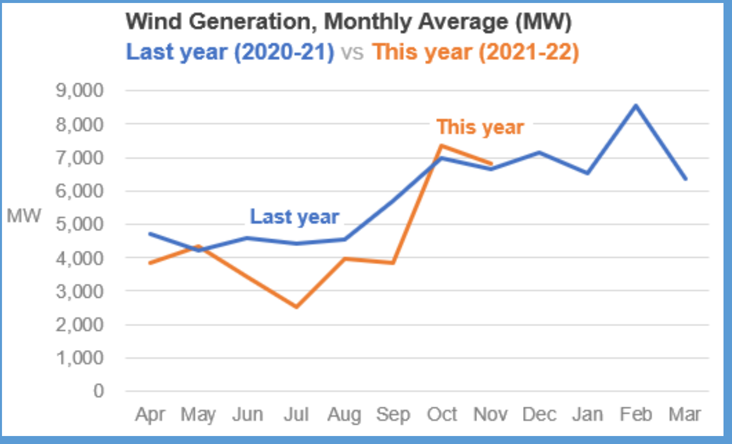
There were several high cost days during November 2021 where expensive actions were needed to ensure all operability requirements were met. During periods of high wind and system outages, expensive actions were required (including actions to provide voltage support) to ensure system inertia remained above the minimum required level.

In November there were 23 days on which the daily spend passed £10m, of which 10 days recorded a daily spend above £20m. The most expensive days were Tuesday 2 November with a daily spend of over £44m, and Wednesday 24 November with a daily spend of nearly £65m. High cost days and balancing cost trends are discussed every week at the Operational Transparency Forum to give ongoing visibility of the operability challenges and the associated Electricity National Control Centre (ENCC) actions.

Significant events

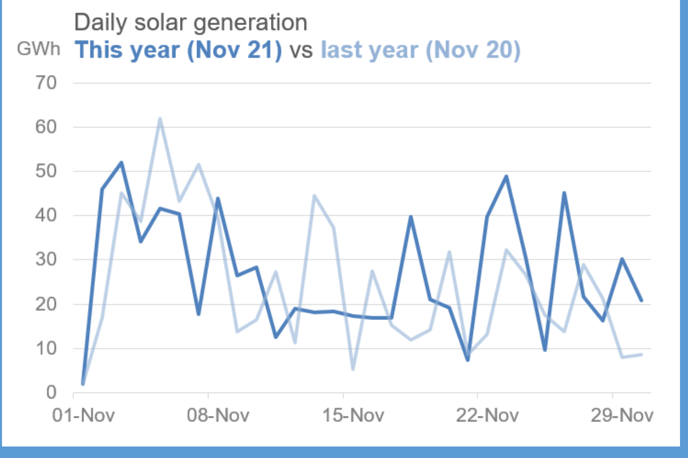
As detailed above, in recent weeks there have been several very high-cost days in the Balancing Mechanism. As those costs are ultimately borne by consumers it is important to fully understand the factors driving the market. The ESO will therefore undertake a review of the balancing market: please see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

Wind generation[2]



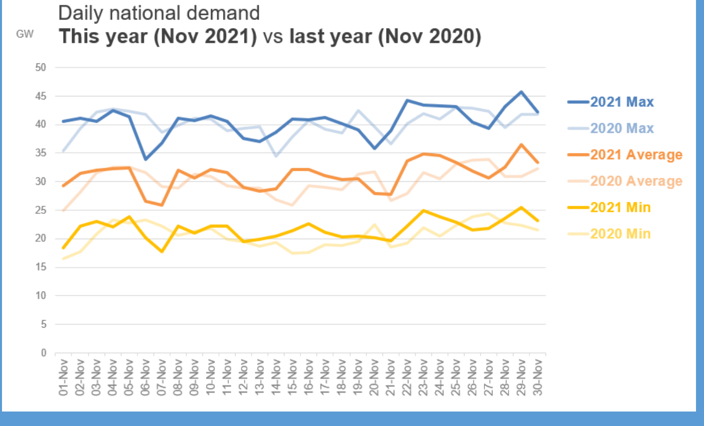
The average wind generation output in November was slightly down from October, and slightly lower than November last year.

Solar generation - comparison against last year



Solar generation this year was higher in the later part of November.

Outturn Demand vs 2020-21



Outturn demand for November this year has been lower than the same period last year. During both 2021 and 2020, no very low demands were observed in November.

[2] The Wind Generation graph and related commentary was corrected in this revised version of the report on 26 January 2022

Metric 1B Demand forecasting accuracy

November 2021 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.

If triad avoidance was detected, it will be accounted for in the data used to calculate performance. The volume of estimated triad avoidance is shared with Ofgem, and we intend to publish it on the Data Portal from January 2022.

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)

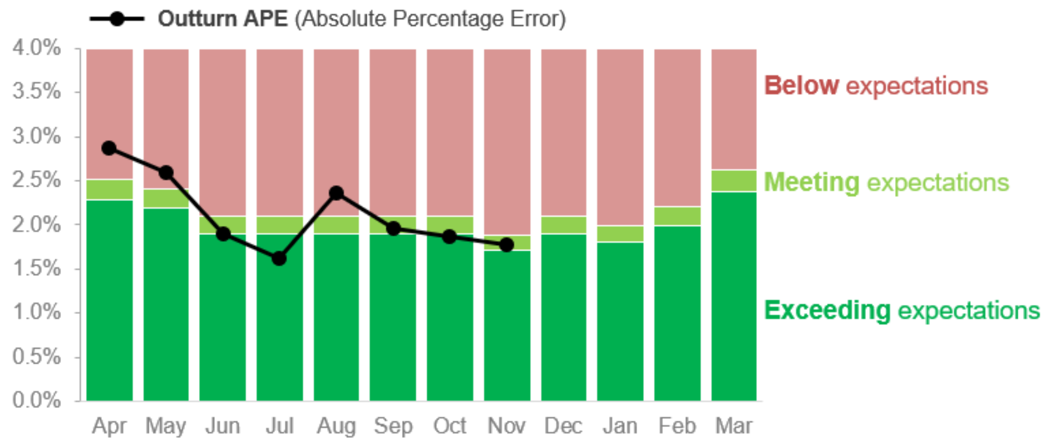


Table 3: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2021-22)

	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**[3]	**1.8**					
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

[3] The October APE was corrected from 2.0% to 1.9% in this re-published version of the November report on 26 January 2022. The October status has changed from 'meeting expectations' to 'exceeding expectations'.

Supporting information

For November 2021, our MAPE (mean absolute percentage error) was 1.8% compared to the benchmark of 1.8% and therefore ‘meeting expectations’.

November’s benchmark of 1.8% is the lowest of the year, in other words the most challenging APE figure to hit.

Storm Arwen and its remnants impacted on performance, and Sunday 26 November & Monday 27 November were the most challenging days in the month for forecasting accuracy.

We continue to use two forecasting models which run in parallel, with the models’ outputs reviewed by experienced forecasters who determine the final forecast. This approach allowed us to meet expectations.

Performance in November 2021: big errors		
Error greater than	No of SPs	% out of the SPs in the month (1440)
1000MW	288	16%
1500MW	84	6%
2000MW	25	2%
2500MW	6	0%
3000MW	1	0%

Triads

November is the first 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.

November is the first month in the “triad avoidance” season. It 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.

In November there were no instances of missed or late publication of forecast data.

Metric 1C Wind forecasting accuracy

November 2021 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)

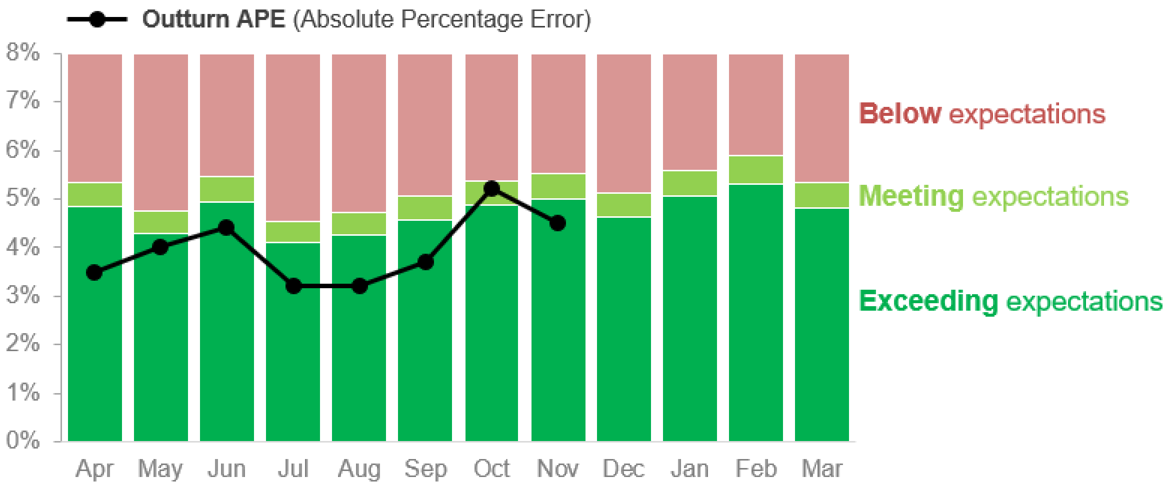


Table 4: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2021-22)

	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**					
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 November 2021, our MAPE (mean absolute percentage error) was 4.5% compared to the benchmark of 5.3% and therefore ‘exceeding expectations’.

November is the month in which the weather can be the most difficult to predict. Wind power forecast error is normally greatest when there are ramping events with wind power transitioning from low to high or vice versa. This is normally caused by low pressure systems moving across the UK and in particular when those systems pass directly over areas with large numbers of wind turbines. This was the case on 1, 6 and 12 November when a low pressure system passed over Scotland.

Another weather feature that brings increased forecasting errors is the remnants of ex-tropical storms. The decomposition of a tropical storm is quite difficult to predict accurately because it tends to decay into lots of smaller, complex weather features. On Monday, 8 November the remnants of ex-Tropical Storm Wanda passed over the UK bringing lots of rain and weather that is more challenging to forecast.

If a low pressure system is particularly strong then it is usually given a name. This was the case on 25 and 26 November when Storm Arwen appeared. Storm Arwen was unusual because it formed north of Scotland and the action of the jetstream pushed it in a southerly direction directly down the east coast of Scotland and England where it passed directly over many wind farms.

Wind farms with Contracts for Difference (CFD) contractual arrangements switch off for commercial reasons when prices are negative for 6 hours or more. This behaviour can affect the amount of wind generation and as price signals cannot be factored into forecasts, this can make our forecasts less accurate. In November there was one occasion when the electricity price went negative, but only for three consecutive hours. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for November can be downloaded here.

In November there were no instances of missed or late publication of forecast data.

Metric 1D Short Notice Changes to Planned Outages

November 2021 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

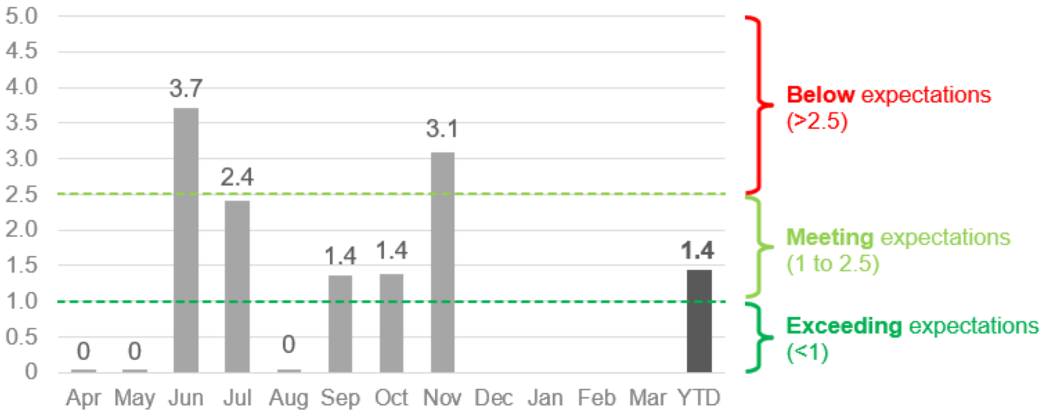


Table 5: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	845	856	810	831	810	735	723	648					6258
Outages delayed/cancelled	0	0	3	2	0	1	1	2					9
Number of outages delayed or cancelled per 1000 outages	0	0	3.7	2.4	0	1.4	1.4	3.1					1.4

Performance benchmarks

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

Supporting information

For November, the ESO has successfully released 648 outages and there has been a total of one cancellation due to an ESO process failure, and one delay. This gives a score of 3.09 delays or cancellations per 1000 outages and therefore in the ‘below expectations’ range.

For April to November as a whole, the total delays or cancellations due to an ESO process failure is 9 out of 6,258 outages. This gives a score of 1.44 per 1000 outages which is within the ‘Meets Expectations’ range. This is an improved performance compared to the same period last year (April 2020 to November 2020) when there were 2.85 cancellations or delays per 1000 outages (17 cancellations/delays out of 5,960 outages).

1. 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) has been 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.

2. 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. We are currently investigating the discrepancy between the two models. We are also in preliminary discussions regarding whether our internal planning tolerances need to be reviewed to further compensate for the discrepancies between the tools.

RRE 1E Transparency of operational decision making

November 2021 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 6: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov
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%
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%
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)

Supporting information

For November, 99.7% of actions were either taken in merit or taken out of merit due to electrical parameters. For the remaining actions, where possible, we allocate actions to reason groups for the purpose of our analysis. We were unable to allocate reason groups for 0.3% of the total actions for this month. Although this remains a low percentage, we continue to look to understand any further trends or reasons for these actions being taken out of merit order.

RRE 1G Carbon intensity of ESO actions

November 2021 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 7: 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				

Supporting information

November 2021 saw an average difference between the carbon intensity of Final Physical Notifications (FPNs) and balancing actions of 9.4gCO2/kWh.

26% of the time the actions taken by the control room lowered the carbon intensity from the market position as we secure and balance the system. The maximum difference was 90.9 gCO2/kWh and the minimum was -24.6gCO2/kWh[4]. It is important to note that the ESO licence does not permit us to take actions based on carbon efficiency, but purely on cost.

Operability challenges caused by renewable volatility continue to be addressed predominantly by running gas generation (primarily Combined Cycle Gas Turbines, CCGT).

Coal, which is has a high carbon intensity, was running for 71% of the settlement periods in the month. This is higher than usual, and most likely caused by the high gas prices.

[4] The minimum difference between the carbon intensity of FPNs and balancing actions was corrected from 24.6gCO2/kWh to -24. 6gCO2/kWh in this re-published version of the November report on 26 January 2022.

RRE 1I Security of Supply

November 2021 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 8: 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				
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz	0	0	0	0	0	0	0	0				
Voltage Excursions defined as per Transmission Performance Report[5]	0	0	0	0	0	0	0	0				

Supporting information

There were no reportable voltage or frequency excursions in November.

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

RRE 1J CNI Outages

November 2021 Performance

This Regularly Reported Evidence (RRE) shows the number and length of planned and unplanned outages to Critical National Infrastructure (CNI) IT systems.

The term 'outage' is defined as the total loss of a system, which means the entire operational system is unavailable to all internal and external users.

Table 9: Unplanned CNI System Outages (Number and length of each outage)

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

Table 10: 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				
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0	0				

Supporting information

In November there was one planned CNI system outage. The outage was required in order to deploy a software release of changes and enhancements to the BM systems. The change, which is detailed in the Role 1 notable events section, 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.

Notable events during November

ESO to conduct review of the balancing market.

In recent weeks there have been some 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 will therefore undertake a review of the balancing market. It will be run by the ESO Market Monitoring Team and will be carried out by external consultants. There are many issues that can, and will, have contributed to the high costs. Our review will seek to ensure that consumers can continue to have confidence in the market. The terms of reference can be found on our website here.

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 – 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. For more details, please see our Virtual Energy System page.

Updates to the Balancing Mechanism (BM) control room systems successfully implemented

With this release, we have removed 8,000 hours of workarounds for our control room engineers by installing automated instruction repeat and data input functionality. This will help them focus on important, value-add activities in an increasingly complex operating environment and ensure their wellbeing. To maintain continued safe and secure system operation, we've made priority asset health updates and implemented changes recommended by internal best practice process reviews. In addition, we can now make better use of wind power, building on the Power Available phase 2 go-live in March 2021, through changes that will improve the economic advice presented to the control room. This is a stepping stone towards achieving our zero-carbon operation ambition. This is the first of a series of releases using our new release-based approach to delivery, in line with our move to an Agile-focused way of working to deliver our transformational plan.

New dataset introduced by the Energy Forecasting team

The Energy Forecasting team introduced an improved dataset on the ESO Data Portal, 2-14 Days Ahead Demand Forecast. Previously, the forecast from day 2 to day 14 was published on the ESO Data Portal for each Cardinal Point: these are points on the demand curve that carry significant meaning.

The team worked on increasing the resolution of the data, and it is now presented for each half hour/ settlement period from 2 to 14 days ahead. The data is refreshed every day, therefore anyone who accesses this dataset benefits from the latest forecast.

The improved dataset has been met with positive feedback from the industry, including at the Operational Transparency Forum.

Role 2 Market development and transactions

RRE 2E Accuracy of Forecasts for Charge Setting

November 2021 Performance

This Regularly Reported Evidence (RRE) shows the accuracy of Balancing Services Use of System (BSUoS) forecasts against the actual outturn charges.

Figure 5: Monthly BSUoS forecasting performance (Absolute Percentage Error)

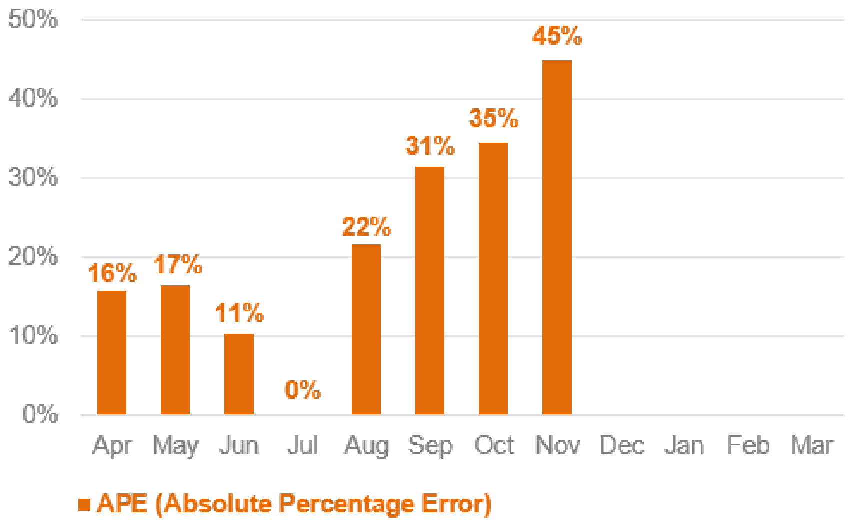


Table 11: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance

	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				
Month-ahead forecast	3.2	3.7	4.1	4.2	4.5	4.7	5.5	6.9				
APE (Absolute Percentage Error)[6]	**16%**	**17%**	**11%**	**0%**	**22%**	**33%**	**35%**	**45%**				

Supporting information

The outturn BSUoS for November was the highest outturn to date this year. Continued high Balancing Mechanism prices impacted significantly on the costs of actions taken to operate the system. Increased wind levels caused constraint costs to rise due to increased congestion on the system, reduced boundary capabilities and the need to synchronise machines for voltage support and inertia.

From January 2022 we will be incorporating a revised data set, forecasting constraint costs in the BSUoS forecasts. This forms part of our Constraints 5 Point Plan, and will provide more accurate forecasting for BSUoS cost scenarios.

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

Notable events during November

Autumn Markets Forum

On 18 November we held our Autumn Markets Forum. 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, reform activities in Response and Reserve, and in 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

The event presentations can be accessed here.

Net Zero Market Reform update published

On 8 November, we also published an update on our Net Zero Market Reform project, which is exploring how GB electricity markets can 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 2 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.

Ofgem approves changes to STOR terms and conditions

On 8 November, Ofgem published its decision to approve proposed amendments to the Short Term Operating Reserve (STOR) terms and conditions (T&Cs) submitted by the Electricity System Operator (ESO) on 1 October 2021. Ofgem stated that it considers that proposals to allow the STOR auctions to compare the costs of overholding, underholding and the original curtailable cost will lead to lower costs to consumers and reduce volatility. These changes have now been implemented by the ESO. The new algorithm was successfully released onto the auction platform on 19 November, with the first auction at 05:00 on 20 November.

Role 3 System insight, planning and network development

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

Notable events during November

Carbon intensity dashboard launched

On 1 November we launched our carbon intensity dashboard. It shows, in real time, the carbon intensity of the system and our balancing actions as well as the current generation mix. It provides unprecedented transparency around and insight into our actions – and how close we're getting to zero carbon operation. The dashboard can be accessed here.

ETYS 2021 published

The Electricity Ten Year Statement (ETYS) is the ESO's view of future transmission requirements and the capability of Great Britain's National Electricity Transmission System (NETS) over the next 10 years. Using the data from our Future Energy Scenarios (FES), we identify points on the transmission network where more transfer capacity is needed to continue to deliver electricity reliably. Once we have assessed the network requirements, we invite stakeholders to propose solutions to these requirements. These proposals are assessed through our Network Options Assessment (NOA) process, where the most economic and efficient solution is given a recommendation to proceed, and others put on hold or stop. See our website here for more details or to download the full publication. The key messages this year are below.

1. Growth in north-south power flows continues with high variability
1. In the next decade the GB Electricity Transmission System will face growing needs in a number of regions
2. Timely delivery of network reinforcements recommended by the NOA will significantly help to reduce network constraints

Launch of Stability Pathfinder Phase 2 commercial tender

The commercial submission window for NOA Stability Pathfinder Phase 2 opened on 9 November. 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 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 earlier this year. These previous steps allowed interested participants to submit and demonstrate the capability of their proposals and also allowed them to provide feedback on various documents.

The submission window is open until 14 January 2022 after which the ESO will carry out an assessment to select the economic combination of solutions to meet the Stability requirement. Further information on Phase 2 can be found here.

NOA Stability Pathfinder Phase 3 update

The Phase 3 invitation to tender was launched 20 December 2021, with tender returns due 16 May 2022. Tender launch was originally planned for November 2021, but was postponed due to detailed power system studies showing significant fault level issues. Following collaboration with NGET these issues have now been mitigated, which if unaddressed would have prevented new solutions from connecting to the majority of our targeted substations.

We have re-opened the expression of interest window for market participants, with a deadline of 31 January 2022.