ESO RIIO2 Business Plan 2 (2023-25)

Mid-Year 2023-24 Incentives Report

24 October 2023

Contents

Introduction

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

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

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

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

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

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

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

Please see our website for more information.

Summary of Notable Events

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

- On 18 September at 2pm, we achieved a new low carbon intensity record of 27g/kWh, beating the previous record of 33g/kWh set earlier this year on 10 April.
- On 28 September we published our Winter Outlook, providing our views on security of UK electricity supply for Winter 2023/24. More information on Winter Outlook can be found here.
- We have started a trial to examine small-scale assets operating in the Balancing Mechanism (BM). This trial allows a temporary relaxation of the existing operational metering standards, for three months for new assets for a limited volume (50MW total, 10MW per company) with the aimed completion date of April 2024. All other market entry obligations will remain the same.
- On 1 September, we announced our intention for the return of the Demand Flexibility Service used last year. We have submitted our proposal for this years' service to the energy regulator Ofgem for their approval. Alongside the formal submission to Ofgem, we have also confirmed details of the service's commercial proposition for the electricity suppliers, aggregators and businesses who directly contract with us.
- We published a long-term projection of Transmission Network Use of System (TNUoS) Tariffs for 2029/30 – 2033/34. Together with the five-year forecast of TNUoS tariffs that we published in April, this will provide industry with a ten-year view of TNUoS tariffs from 2024/25 to 2033/34. We hosted an industry webinar on the 25 September to help the industry better understand the publication.
- On 28 September, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our control room certainty that they can use this vital tool when required for system security over the coming years.
- Following the July Transmission Charging Methodology Forum (TCMF) a survey was sent out to gain feedback from attendees to understand what works well and also how TCMF can be improved to ensure it continues to be a useful forum for all. There was an average score of 8 on a scale of 1-10 (10 being extremely positive) when asked how useful and informative TCMF is.
- On 28 September, the GB Connections Process & Solutions team held a workshop for all customers of the Connections Portal. We were joined by around 100 customers and had really positive engagement with them throughout. The feedback that we captured has since been scored and prioritised on the project backlog.
- On 21 September, we hosted the 'How will the Virtual Energy System be built?' webinar. Over 100 attendees (including the ESO, National Gas, DNO, UKPN, Energy Security, Government and regulators) joined to learn about our Virtual Energy System, unpack the 6 priority factors in detail and hear about our next steps.
- On 28 September, we hosted a workshop with stakeholders to gather views on the draft framework for the next publication of our Future Energy Scenarios (FES). We were joined by over 30 stakeholders and feedback will now be considered to help improve the development of our plans in the near future.
- On 26 September we held our third Connections Issues Steering Group (CISG) subgroup meeting. Information on this session can be found here. The first CISG sub-group meeting, in July, focused on Connections strategic change and impact to the Connections and Use of System Code (CUSC). The CUSC panel suggested that there would be value in having further sessions to understand our proposed changes to the connection process and new policy, resulting in the most recent subgroup meeting.

In the first six months of BP2 we successfully delivered the following notable events and publications. Please refer to previous reports for full detail:

- In April, we published our refreshed 2023-24 ESO Innovation Strategy. The strategy sets out how we plan to innovate in 2023-24 and where we need to focus our efforts to help achieve our ambitions for 2025 and beyond.
- On 5 April, we announced the completion of the first phase of our Stability Pathfinder programme, which aimed to support the development and delivery of new technologies to generate important system characteristics, such as inertia. With the delivery of the final unit of this phase, the use of improved technology is expected to deliver up to £128m in consumer savings over its lifetime as well as reduce CO_2 emissions by ~6mn tonnes.
- In May, for the Coronation of King Charles III and Queen Camilla, we created a bespoke planning team with SMEs from across ESO teams, including the duty control room team on the day of the coronation. The duty control room team successfully maintained the second-by-second system frequency within normal limits throughout the event, 49.8 - 50.2 Hertz, and there were no instances to threaten transmission system security. Thus, we were able to successfully play our part during this historic Royal occasion.
- At the beginning of June we published the final report for the Powerloop trial, which we ran with Octopus Energy in 2022. The trial was the first of its kind for the Great Britain energy system, linking actions taken in the Electricity National Control Centre (ENCC) to domestic household Electric Vehicles (EVs) charge points.
- To support the energy industry's preparations for Winter 2023/2024, on 15 June we published our Early View of Winter Outlook report, to give organisations across the UK energy industry time to prepare for the coming winter
- On 10 July, we launched our 2023 Future Energy Scenarios report which set out a range of different, credible ways to decarbonise our energy system as we strive towards the 2050 net zero target. We were joined by nearly 100 stakeholders at the Science Museum in London for the first of our 2023 launch events, where we presented the key messages from FES and provided the opportunity for questions to our panel of speakers.
- On 26 July, we published the Innovation Annual Summary (PDF version here). It features case studies which introduce some of our key innovation projects. Each case study has a useful 1-minute explainer video from our project leads, these can be found as part of our interactive 2022/23 Innovation Annual Summary here. It's a great introduction to innovation and learning more about how we're tackling the challenges of the energy transition throughout the ESO.
- On 29 August, we published the 2023 Electricity Ten Year Statement (ETYS), which shows our view of GB's National Electricity Transmission System (NETS) over the next 10-20 years. This is an annual document which helps us to understand the future requirements of the system and where investment and development is needed to help us achieve our zero-carbon ambition.

Summary of Metrics and RREs

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

Table 1: Summary of Metrics

Metric			Unit	Apr	May	Jun	Jul	Aug	Sep	YTD Status
1A	Balancing Costs		£m	198	132	114	238	171	225	●
1B	Demand Forecasting		MW	791	524	546	569	465	523	●
1C	Wind Generation Forecasting		%	4.7%	4.1%	4.5%	6.3%	5.9%	7.2%	●
1D	Short Notice Changes to Planned Outages		#	1.5	2.6	0	0	2.8	1.4	●
2Ai	Phase-out of non-competitive balancing services	FR & Reserve	%	Q1: 23%			Q2: 23%			●
		Reactive	%	Q1: 97%			Q2: 97%			●
		Constraints	%	Q1: 98%			Q2: n/a			●
2X	Day-ahead procurement		%	Q1: 64%			Q2: 67%			●

Below expectations ● Meeting expectations ● Exceeding expectations ●

Table 2: Summary of RREs

RREs don't have performance benchmarks (with the exception of 2D which is reported annually).

RRE	Title		Unit	Apr	May	Jun	Jul	Aug	Sep
1E	**Transparency of Operational Decision Making**		%	**94%**	**91%**	**98%**	**93%**	**96%**	**97%**
1F	**Zero Carbon Operability indicator**		%		Q1: **84%**			Q1: **89%**	
1G	**Carbon intensity of ESO actions**		gCO2 /kWh	**4.7**	**1.9**	**2.8**	**11.6**	**5.2**	**10.7**
1H	**Constraints cost savings from collaboration with TOs**		£m		Q1: **£417m**			Q2: **£152m**	
1I	**Security of Supply**		#	**-**	**-**	**1**	**-**	**-**	**-**
1J	**CNI Outages - Planned**		#	**-**	**-**	**1**	**-**	**-**	**1**
	CNI Outages - Unplanned		#	**-**	**-**	**-**	**-**	**-**	**-**
2Aii	**Balancing services procured in a non-competitive manner**		#		Q1: **£94m** spend, volume: **19 TWH** and **15 TVARH**			Q1: **£58m** spend, volume: **16 TWH** and **10 TVARH**	
2B	**Diversity of service providers**		n/a		See report				
2E	**Accuracy of Forecasts for Charge Setting (BSUoS):** *Month ahead APE (absolute percentage error)*		%	**18%**	**68%**	**43%**	**29%**	**7%**	**11%**
3A	**Future savings from Operability Solutions**		£m	i) Saved balancing costs: **£45m** (Constraints Management Pathfinder B6 extension)					
				ii) Saved infrastructure costs: **£33m** (Constraints Management Pathfinder B6 extension)					
				iii) Indicative impact on the SZCP limit: see report					
3X	**Timeliness of Connection Offers** *Number of offers made (from clock-start date):*	**Within 3 months**	#		Q1: **357**			Q2: **369**	
		Longer than 3 months	#		Q1: **0**			Q2: **6**	
3Y	**Percentage of 'right first time' connection offers**		%		Q1: **93%**			Q2: **95%**	

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

Adelle Wainwright
Acting ESO Regulation Senior Manager

Role 1 (Control Centre operations)

ESO

Metric 1A Balancing cost management

This metric measures the ESO's outturn balancing costs (including Electricity System Restoration costs) against a balancing cost benchmark.

A new benchmark has been introduced for BP2. Analysis has shown that the two most significant measurable external drivers of balancing costs are wholesale price and outturn wind generation. The new benchmark has been derived using the historical relationships between those two drivers and balancing costs:

i. The benchmark was created using monthly data from the preceding 3 years.

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

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

iv. Ex-post actual data inputted into the equation created by the historic relationships to create the monthly benchmarks.

The formulas used are as follows (with Day Ahead Baseload being the measure of wholesale price):

Non-constraint costs = 54.48 + (Day Ahead baseload x 0.52)
Constraint costs = -32.66 + (Day Ahead baseload x 0.34) + (Outturn wind x 25.72)

Benchmark (Total) = 21.82 + (Day Ahead baseload x 0.86) + (Outturn wind x 25.72)

**Constants in the formulas above are derived from the benchmark model*

ESO Operational Transparency Forum: The ESO hosts a weekly forum that provides additional transparency on operational actions taken in previous weeks. It also gives industry the opportunity to ask questions to our National Control panel. Details of how to sign up and recordings of previous meetings are available here.

September 2023-24 performance

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

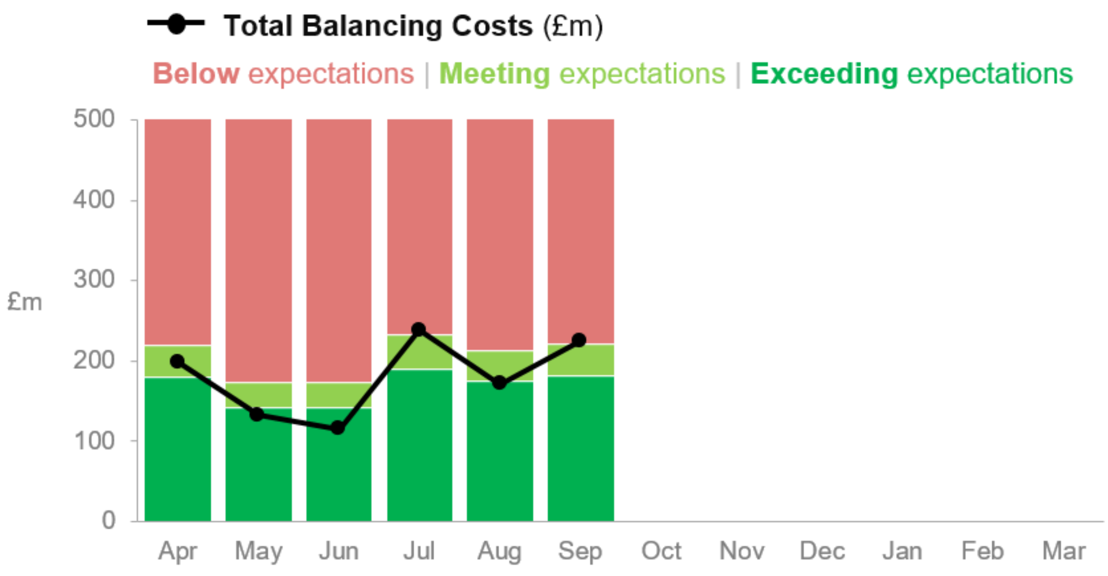


Table 1: 2023-24 Monthly breakdown of balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Outturn wind (TWh)	3.4	2.6	2.4	4.6	3.8	4.2							20.98
Average Day Ahead Baseload (£/MWh)	105	81	87	82	86	83							n/a
Benchmark	200	157	158	212	194	201							1122
Outturn balancing costs[1]	**198**	**132**	**115**	**238**	**171**	**225**							**1080**
Status	●	●	●	●	●	●							●

Previous months' outturn balancing costs are updated every month with reconciled values. Figures are rounded to the nearest whole number, except outturn wind which is rounded to one decimal place.

Performance benchmarks:

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

Supporting information

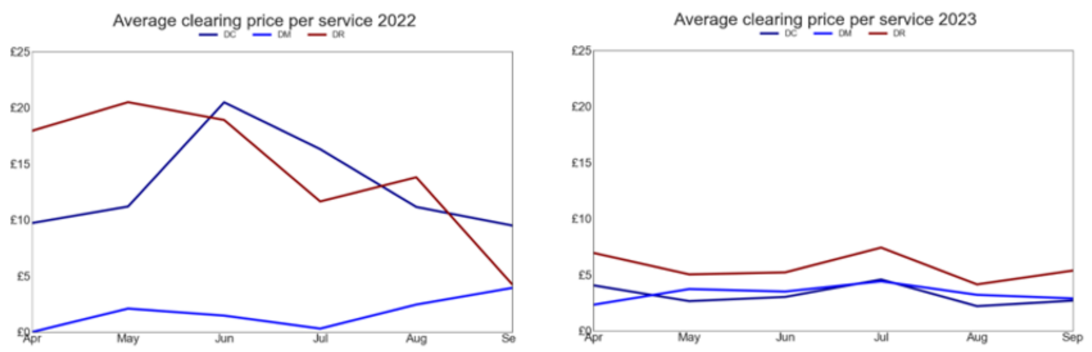
ℹ	**Ongoing data issue:**	Please note that due to a data issue, over the previous months the Minor Components line in Non-Constraint Costs is capturing some costs which should be attributed to different categories. It has been identified that a significant portion of these costs should be allocated to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

Balancing cost strategy update

In April 2023, and as part of our RIIO-2 Business Plan (BP2), we established a new Balancing Costs Team in response to recent increases in balancing costs. The team's purpose is to provide analysis and commentary around causes and influences of balancing costs, and to drive business and industry change with the aim of finding the right balance of balancing costs. Since April, the team has grown to four permanent members of staff, and has been providing new analysis, insights, and reports on balancing costs. We have also been driving new initiatives that will help minimise further increases to balancing costs which we will be sharing more detail on as they progress.

In September, as part of this new team's work, we published a new balancing costs webpage to showcase our strategy and portfolio of initiatives to minimise balancing costs, along with unique insights and analysis. The strategy highlights four key levers (see below) that we have been using to introduce new ways of minimising costs that have had a significant impact of the last six months.

[1] Outturn balancing costs excludes Winter Contingency costs for comparison to the benchmark as agreed with Ofgem. However, in the rest of this section we continue to include those costs for transparency and analysis purposes.

Network Planning & Optimisation	We have been able to make a significant amount of savings, firstly through the Constraint Management Pathfinder (Intertrip Service) that was implemented in April 2022, which has been generating about £200m per year in balancing cost savings. Another Intertrip Service is set to initiate in October 2023. We have also been further optimising and improving our outage procedure to maximise flows on the electricity system by minimising constraint costs. Our Outage Optimisation initiatives have saved up to £578m in balancing costs in 2023/24 so far.
Commercial Mechanisms	As part of our Business Plan, we have been building the future balancing service and wholesale markets by introducing new Dynamic Services. In 2023/24 we have started to see the benefit of more competitive and more liquid markets for our new ancillary services Dynamic Containment (DC), Dynamic Moderation (DM) and Dynamic Regulation (DR). The plots below show the average clearing price for each of these services (high and low combined) for April 2022 to Sept 2022 (left) compared with April 2023 to Sept 2023 (right). The mean of the average clearing price for the first half of this financial year is £3.24/MW/h compared to £13.79/MW/h last year for DC, and £5.68/MW/h this year for DR compared £14.50/MW/h for the same period last year. This is because of an increase in number of market participants, certainty around requirements and the auction process due to the continued development of the Single Market Platform. There has been a slight increase in the mean of the average clearing price for DM, however, of £3.34/MW/h in the first half of this financial year compared to £1.71/MW/h for the same period last year. This is because the DM market is less developed than the DC and DR markets. We have been taking action to develop the market and we are now procuring larger volumes than last year. **GRAPH: The introduction of new market mechanisms has led to more competitive and cheaper prices for these services.** 
Research, Innovation, and Engagement	Inertia costs are a balancing cost segment that has seen significant savings realised in the last six months since the introduction of some of our more innovative initiatives. Monthly inertia costs have decreased by nearly £40m in some months from their peak in April 2020, which is a 96% reduction in monthly costs. Our Frequency Risk and Control Report (FRCR) dynamically assesses the magnitude, duration, and likelihood of transient frequency deviations, the forecast impact and the cost of securing the system. It allows us to change the system's inertia requirements to suit the system conditions. So far in 2023/24 we have realised notable savings in balancing costs associated with inertia through both the FRCR and the introduction of the new Stability Pathfinder.

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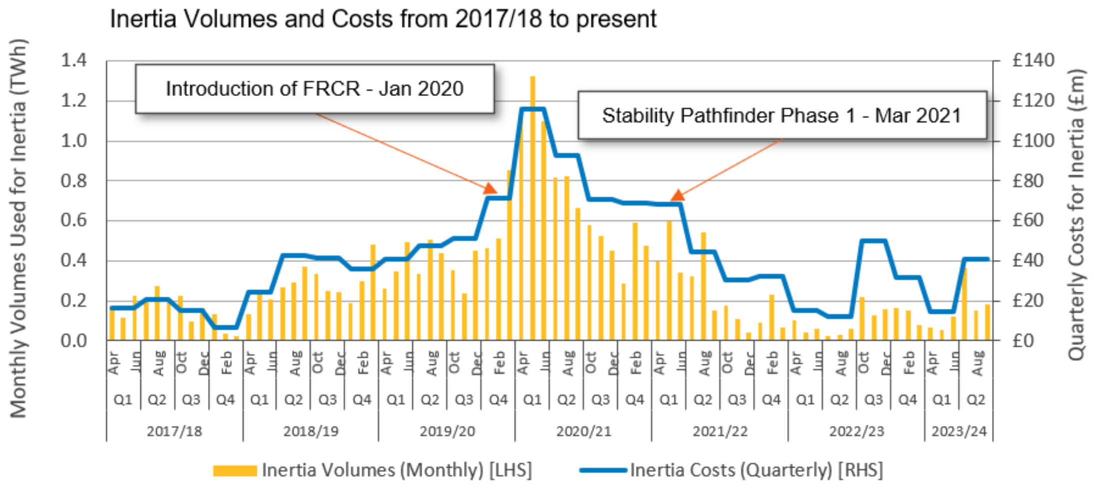
GRAPH: Inertia volumes and costs reduced significantly since the introduction of FRCR and the Stability Pathfinder.



Other benefits resulting from FRCR include the reduction in costs of managing the largest loss, see here for details.

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The major initiative that will contribute to Balancing Cost savings in this lever is the Balancing Programme, which will see better integration of Distributed Energy Resources (DER), improved forecasting capabilities, and more efficient dispatching capabilities. The first release of this program is scheduled for the end of calendar year 2023.

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A comprehensive list of the initiatives that we are undertaking and how they fit into our Balancing Costs Strategy can be found on the Balancing Costs webpage but we are constantly looking for engagement on new initiatives and ideas that can be utilised to minimise balancing costs.

One such case was the workshop on balancing costs that we held on 25 July with key industry and government members. This forum provided an opportunity for open discussion and views to be expressed on the causes of balancing costs and ways of mitigating high costs in the future.

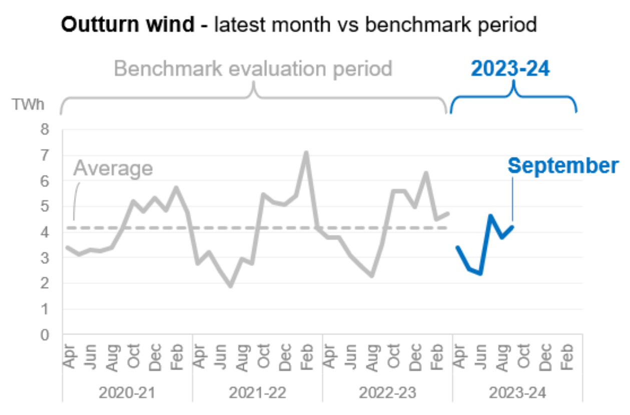
We are also continuing to hold regular workshops and discussions with DESNZ and Ofgem. Four workshops have been held with both organisations in order to better understand balancing costs and what can be done to strike a better balance. We plan to host more forums outside of the Operational Transparency Forum (OTF) in the future with industry and will continue with our engagements with DESNZ and Ofgem.

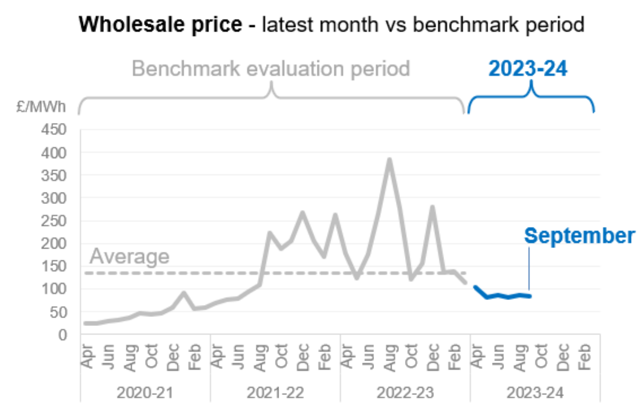
This month’s benchmark

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

The September benchmark of £201m reflects:

- an **outturn wind** figure in line with the average for the benchmark evaluation period (the last three years).
- a relatively low average monthly **wholesale price** (Day Ahead Baseload) compared to the benchmark evaluation period (the last three years).





September performance

September's total balancing costs were £225m which is £24m and 12% above the benchmark of £201m, and therefore below expectations. As you can see from the above graphs, although this month the average wholesale price remained in line with last month, the wind outturn increased slightly. We also saw wind forecast accuracy exceed expectations for the first half of the month, until the change in weather and highly variable winds arrived as outlined in the Metric 1C Wind forecasting accuracy section of this report. These weather patterns led to a week of very high wind forecast errors and high wind curtailment volumes shown in the 'Wind Curtailment, Daily Costs' section further below. This is one of the contributing factors to an increase in balancing cost actuals of £50.8m between August and September.

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

		(a) Aug-23	(b) Sep-23	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-0.3	8.1	8.3	
	Operating Reserve	12.5	11.5	(1.0)	
	STOR	3.1	3.4	0.3	
	Negative Reserve	0.4	0.5	0.1	
	Fast Reserve	14.4	13.2	(1.2)	
	Response	17.8	18.1	0.4	
	Other Reserve	1.1	0.7	(0.4)	
	Reactive	15.0	14.2	(0.7)	
	Restoration	2.6	2.8	0.2	
	Winter Contingency	0.0	0.0	0.0	
	Minor Components	6.5	5.9	(0.6)	
Constraint Costs	Constraints - E&W	48.7	47.7	(1.0)	
	Constraints - Cheviot	4.6	0.7	(3.9)	
	Constraints - Scotland	23.3	53.7	30.4	
	Constraints - Ancillary	3.4	0.2	(3.2)	
	ROCOF	8.2	8.9	0.7	
	Constraints Sterilised HR	12.9	35.3	22.4	
Totals	Non-Constraint Costs - TOTAL	73.0	78.5	5.4	
	Constraint Costs - TOTAL	101.1	146.5	45.4	
	Total Balancing Costs	**174.2**	**225.0**	**50.8**	

Breakdown of costs vs previous month

As shown in the total rows from the table above, both non-constraint & constraint costs increased by £5.4m & £45.4m respectively, resulting in an overall increase of £50.8m compared to August 2023.

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

- **Constraint-Scotland**: £30.4m increase, over 325GWh more than the previous month.

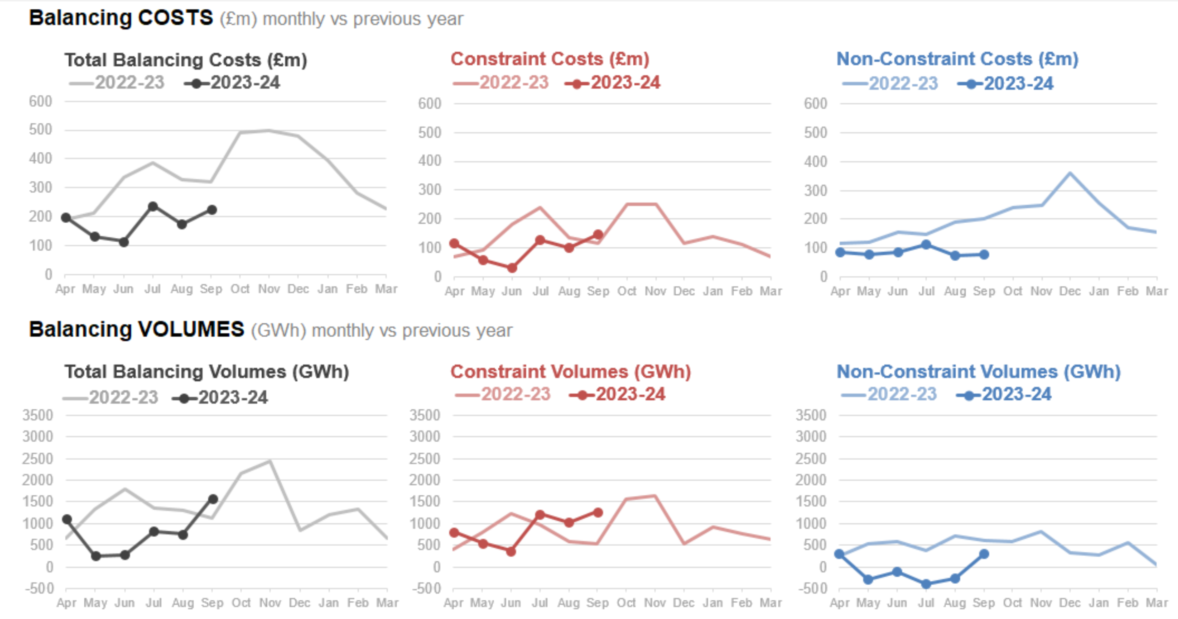
- **Constraints Sterilised Headroom**: £22.4m increase. Cost increase is in line with the increasing of constraint actions because more headroom had to be replaced using Balancing Mechanism (BM) actions on the system outside the constraint (~600GWh more than last August).

* High wind generation resulted in a higher volume of constraint actions.

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

- **Energy Imbalance**: £8.3m increase, due to 400GWh more from the absolute amount of energy required to balance the system this month compared to the previous month.

Constraint vs non-constraint costs and volumes



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

Constraint costs

Compared with the same month of the previous year:	Constraint costs were £31m higher than in September 2022 due to: • an increase in volume of actions - more than 750GWh were required to manage constraints
Compared with last month:	Constraint costs were £46m higher than in August 2023 due to: • an increase in volume of actions - more than 240GWh were required to manage constraints

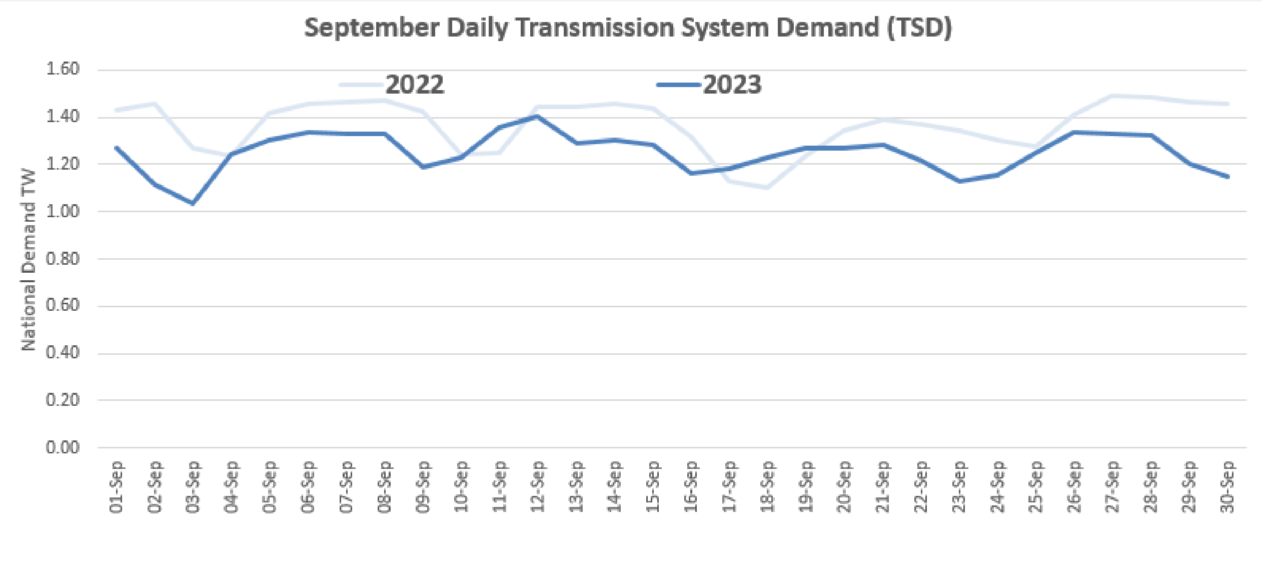
Non-constraint costs

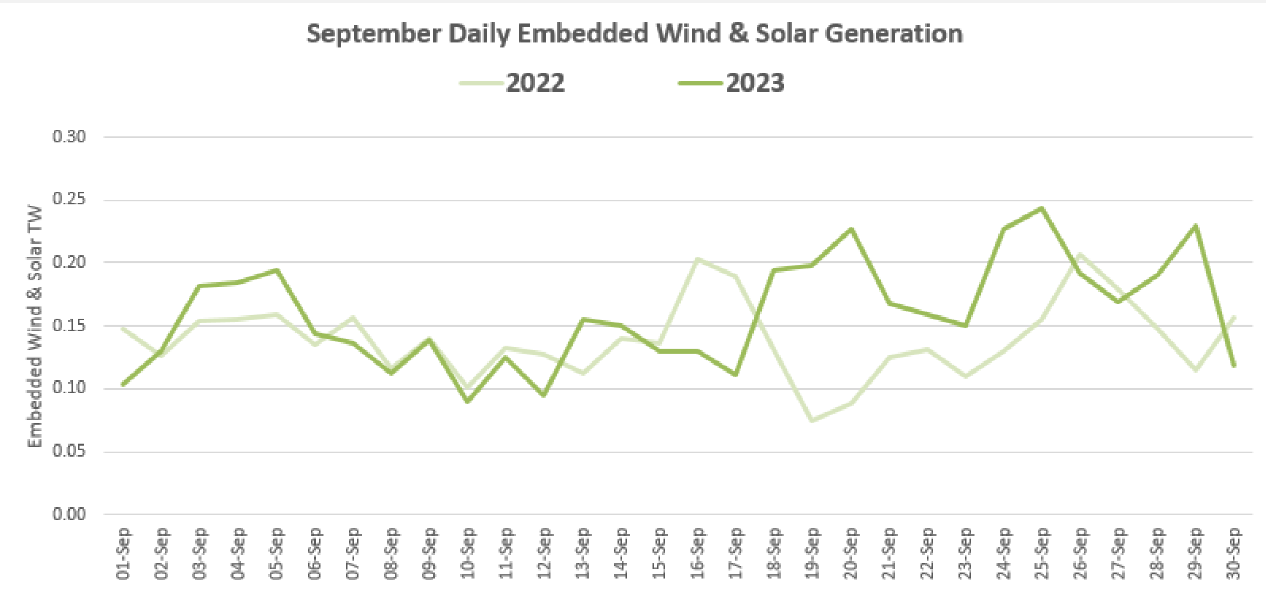
Compared with the same month of the previous year:	Non-Constraint costs were £124.8m lower than in September 2022 due to: • a decrease of the volume of actions (305 GWh less than the previous year) • Lower average wholesale prices **
Compared with last month:	Non-Constraint costs were £5.4m higher than in August 2023 due to: • ~580 GWh higher* volume of actions * The Non-Constraint category consists of several subcategories including imbalance, response, reserve and restoration.

** *Average wholesale prices September-23 £83 /MWh compared to £278/MWh of September-22*

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

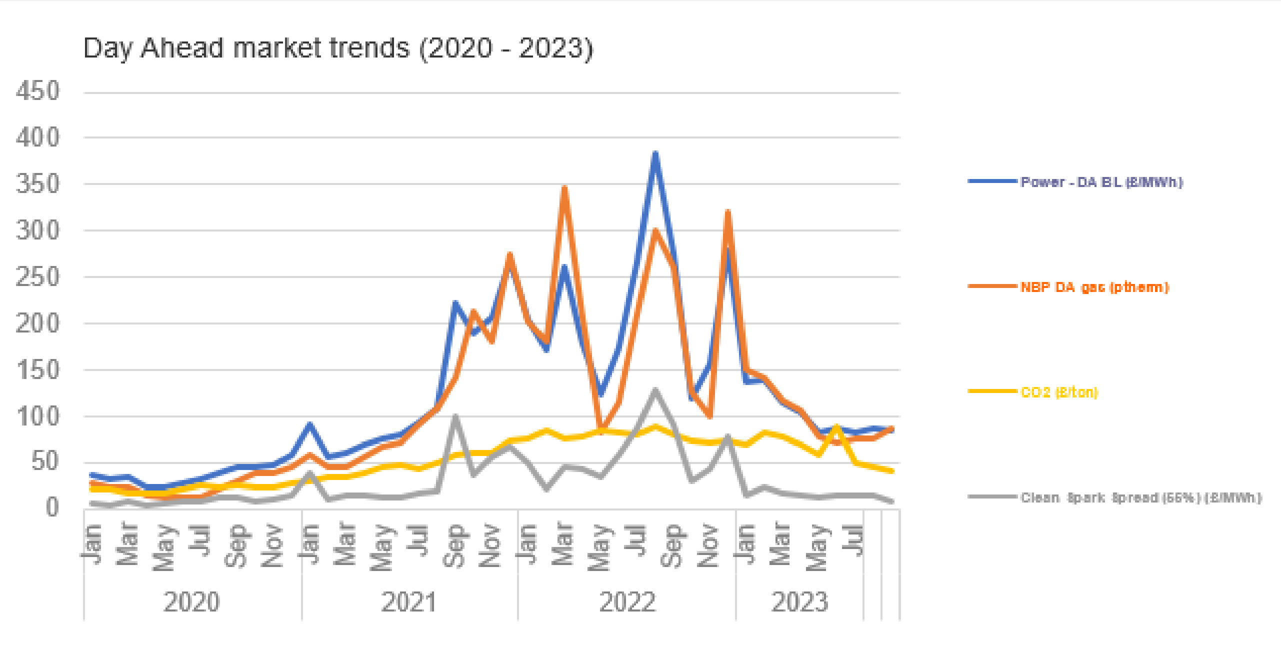
- **National Demand** (not shown below) was 0.4TW lower than the same period last year
- **Transmission System Demand*** was 3.5TW lower than September 2022.
- **Embedded wind & solar generation** was 600GW higher than the corresponding period last year.





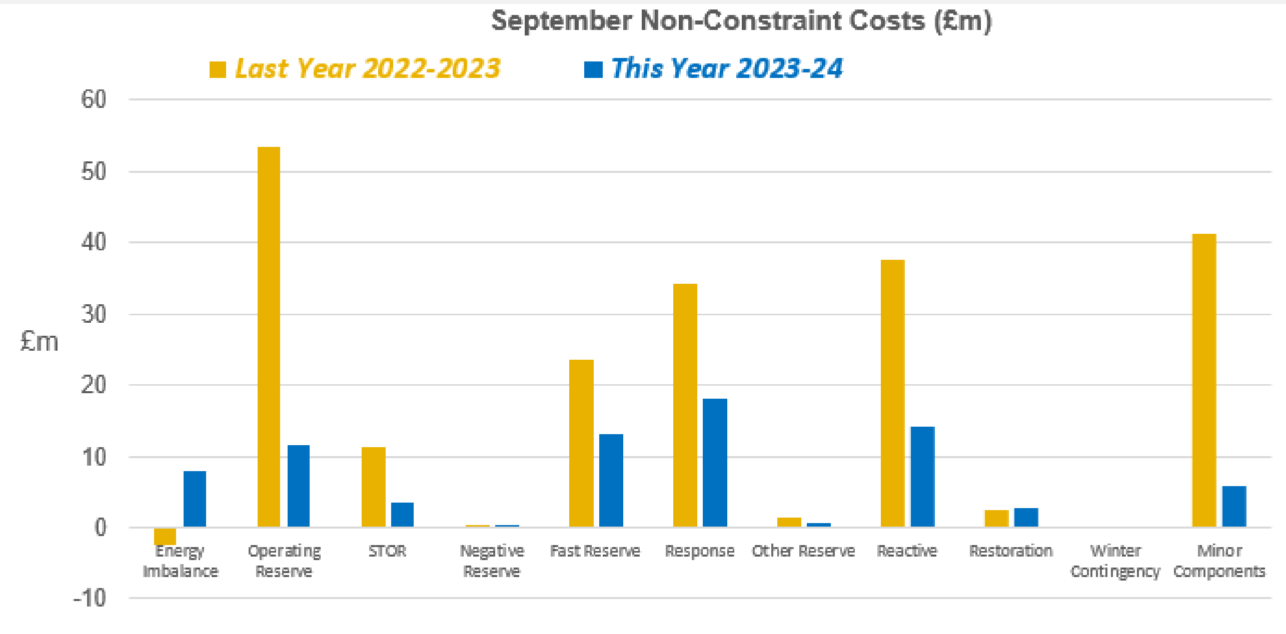
* Transmission System Demand is equal to the National Demand (ND) plus the additional generation required to meet station load, pump storage pumping and interconnector exports. Transmission System Demand is calculated using National Grid ESO operational metering. Note that the Transmission System Demand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

Changes in energy balancing costs



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

All trends decreased or had a small deviation from last month and remain lower compared to the previous year.

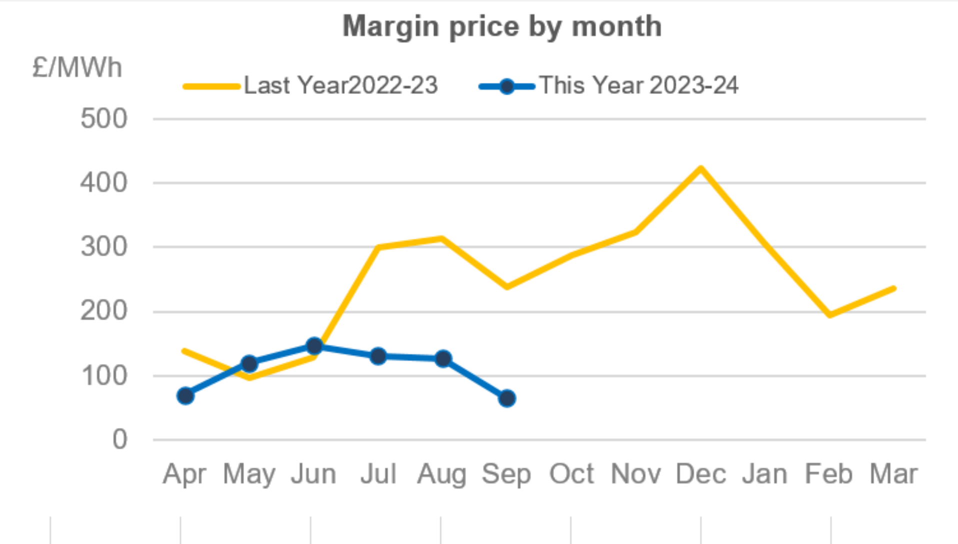


Comparing the non-constraint costs of September 2023 with those of September 2022, the most categories showed a decrease:

- **Operating Reserve** £41.8m decrease due to ~323GWh less volume of actions taken to balance the system and the lower average wholesale prices
- **Reactive** £23.4 m decrease despite the higher volume of MVAR required this September, due to a significant drop in the weighted average price.
(September 22: £12.6 per MVAR vs September 23: £4.4 per MVAR)
- **Response decreased** by £16.1m, due to lower average wholesale prices and a ~50GWh decrease in the absolute volume of actions.

- **Minor Components decreased** by £35.4m. Last year's excessive cost contained incorrectly allocated cost from operating reserve that we have identified in the last end of the year report.

Drivers for unexpected cost increases/decreases



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

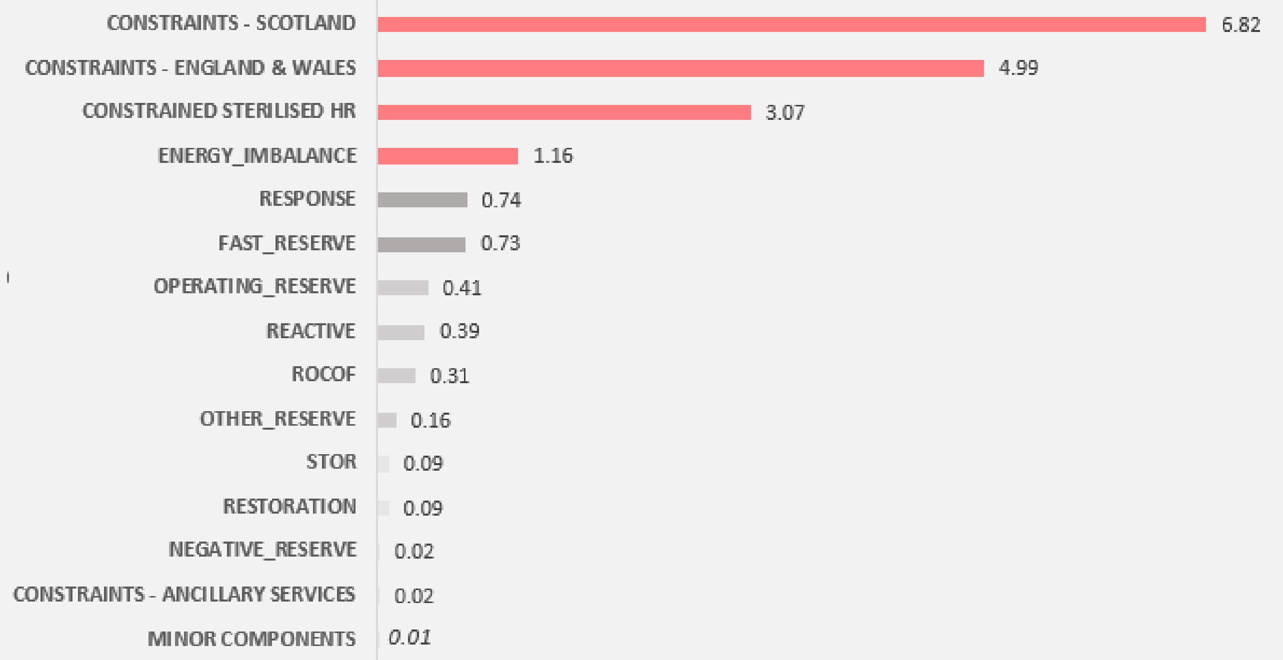
Daily Costs Trends

As stated above, September's balancing costs were £50.8m higher than the previous month.

At the date of publication, we have recorded 5 days with a spend of more than £15m (maximum £19m).

The highest total cost observed on the Saturday 28 September when the total spend was £19m, the major cost components were the thermal constraints driven by high renewable generation. No individual action was expensive, but high volumes of wind curtailment resulted in high total balancing costs.

Cost breakdown for 28 September 2023



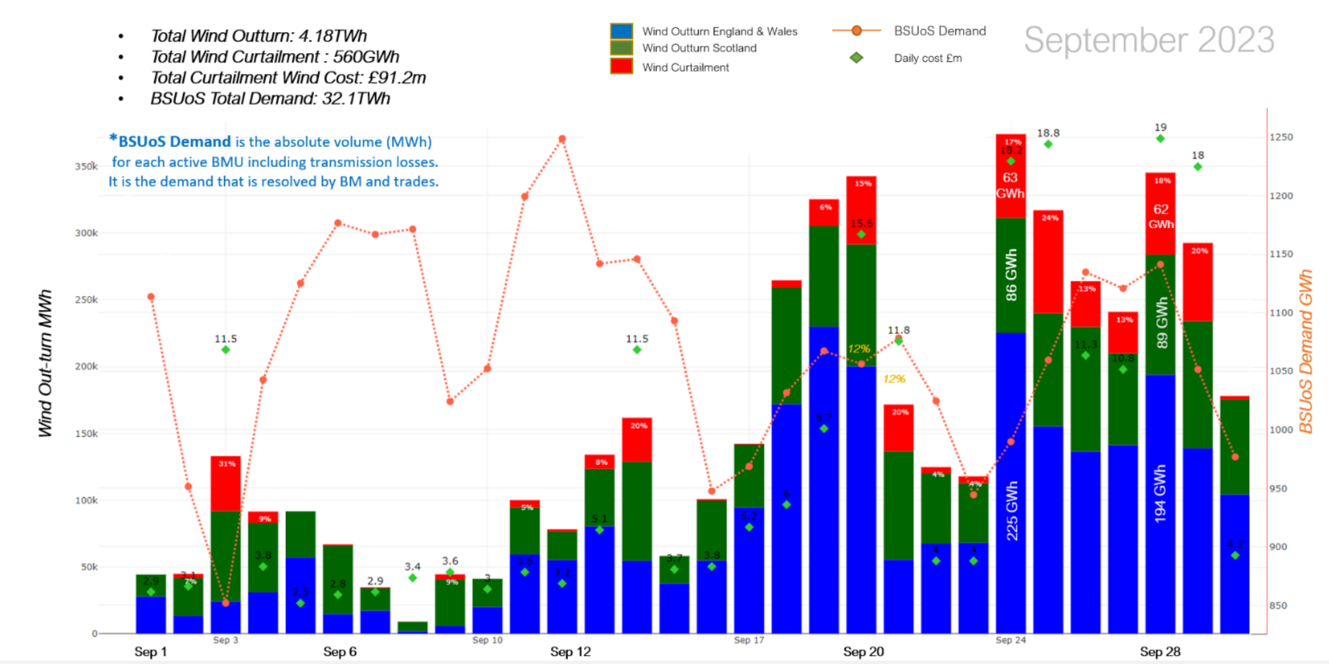
The minimum cost of £2.5m was observed on 05 September.

The average daily spend for the month was £7.6m, a £2m increase from the previous month.

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

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

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



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

Metric 1B Demand forecasting accuracy

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

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

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

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

September 2023-24 performance

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

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

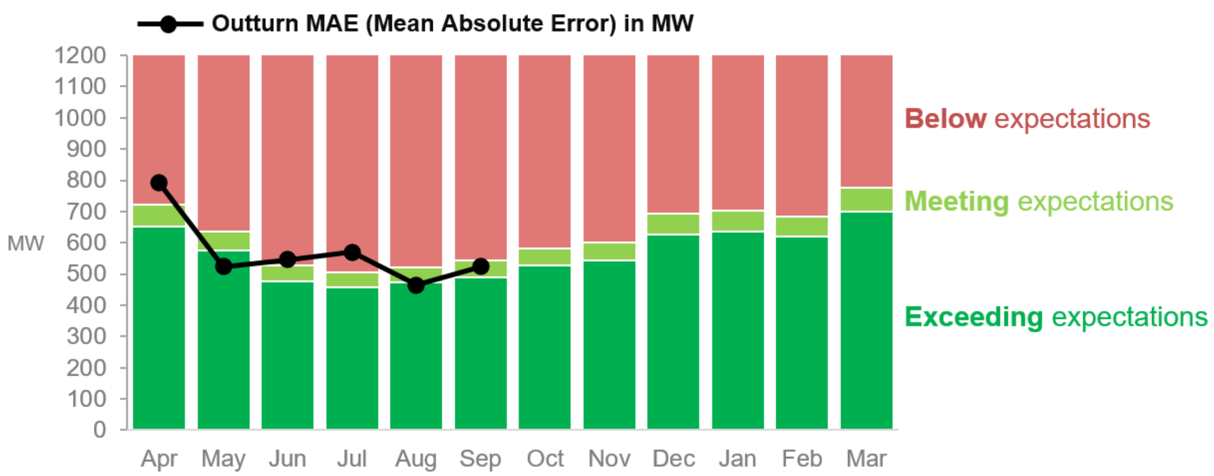


Table 2: 2023-24 Monthly absolute MW error vs Indicative Benchmark

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD (average)
Indicative benchmark (MW)	687	606	503	481	497	516	554	571	659	669	651	738	**548**
Absolute error (MW)	**791**	**523**	**546**	**569**	**465**	**523**							**570**
Status	●	●	●	●	●	●							●

[2] Demand | BMRS (bmreports.com)

Performance benchmarks:

- **Exceeding expectations:** >5% lower than 95% of average value for previous 5 years
- **Meeting expectations:** ±5% window around 95% of average value for previous 5 years
- **Below expectations:** >5% higher than 95% of average value for previous 5 years

Supporting information

In September 2023, the mean absolute error (MAE) of our day ahead demand forecast was 523 MW compared to the indicative ‘meeting expectations’ target of 542 MW. Over the first six months, the MAE of our day ahead demand forecast was 570 MW compared to the indicative ‘meeting expectations’ target of 548 MW.

September was a month of two halves; according to the Met Office “High pressure influenced the UK's weather for the first half of the month, bringing fine, sunny, dry conditions and the most significant spell of warmth since June. The second half of September saw an abrupt change to much more unsettled and autumnal weather with westerly weather bringing Atlantic low pressure systems and significant rain”.

Demand forecast expectations were achieved this month, even though the unusually warm temperatures and extended periods of sunshine are very uncommon for this time of year. The role of the duty Demand Forecaster is to manually amend absolute forecasts, during periods of unusual or changing weather patterns.

The days with largest MAE were 5, 19, 24 and 29 September, with a peak error of 2.8GW on 29 September. This was mainly due to embedded solar forecast errors, with other error contributions from embedded wind and temperature variance.

The distribution of settlement periods by error size is summarised in the table below:

Error greater than	Number of SPs	% out of the SPs in the month (1440)
1000 MW	204	14%
1500 MW	61	4%
2000 MW	20	1%
2500 MW	4	0%

Missed / late publications

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

Triads

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

Metric 1C Wind forecasting accuracy

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

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

September 2023-24 performance

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

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

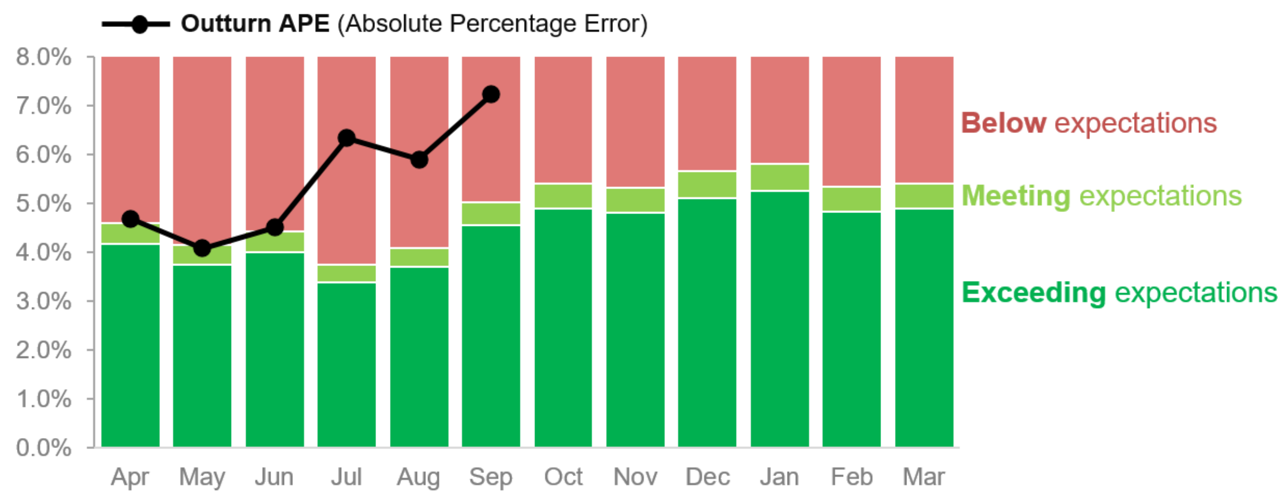


Table 3: 2023-24 BMU Wind Generation Forecast APE vs Indicative Benchmarks

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD (average)
Indicative benchmark (%)	4.38	3.95	4.21	3.57	3.89	4.79	5.15	5.06	5.38	5.53	5.08	5.14	4.13
APE (%)	**4.69**	**4.08**	**4.50**	**6.34**	**5.90**	**7.23**							**5.46**
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

September's wind power forecast accuracy was 7.2% compared to the benchmark of 4.9% and therefore below expectations.

The first half of September was dominated by high pressures, bringing sunny, dry and low wind conditions. From mid-month this abruptly changed to much more unsettled, highly variable conditions with wet and windy days brought on by westerly weather from Atlantic low-pressure systems. This included storm Agnes from 27 September.

Wind forecast accuracy exceeded expectations for the first half of the month, until the change in weather and highly variable winds arrived. These weather patterns led to a week of very high errors, peaking at 5.7GW on 17 September. Discussions with the Met Office and an internal investigation into this day are ongoing.

As mentioned in the August report, in light of sustained errors throughout July & August, we carried out an audit of the wind farm portfolios. This revealed a number of BMUs that weren't being included in the calculation for this metric. We have now updated the systems so that all the BMUs relevant to the Metric 1C calculation are included. We do not believe this has had a significant impact on the previously reported figures and it is deemed to have had minimal contribution to the overall poor performance of late.

Additionally, we have recently completed a full manual audit and update of the models and associated parameters for all these BMUs. These initial changes were implemented in mid-October, and we expect this to lead to improved performance on this metric in future months.

Work is underway to further improve accuracy, through the modelling of High Speed Shutdown effects and that of planned windfarm outages.

While the Intermittent Market Reference Price (IMRP) did go negative for on multiple occasions throughout the month, none of these were for more than 6 hours consecutively (3 hours between 19th – 20th and 2 hours on 28th).

Over the first 6 months the average wind power forecast accuracy was 5.46% compared to the average benchmark of 4.13% and therefore below expectations.

Withdrawal of wind units

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

Missed / late publications

In September there were no occasions of late or missing publications of the forecast.

Metric 1D Short Notice Changes to Planned Outages

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

September 2023-24 performance

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

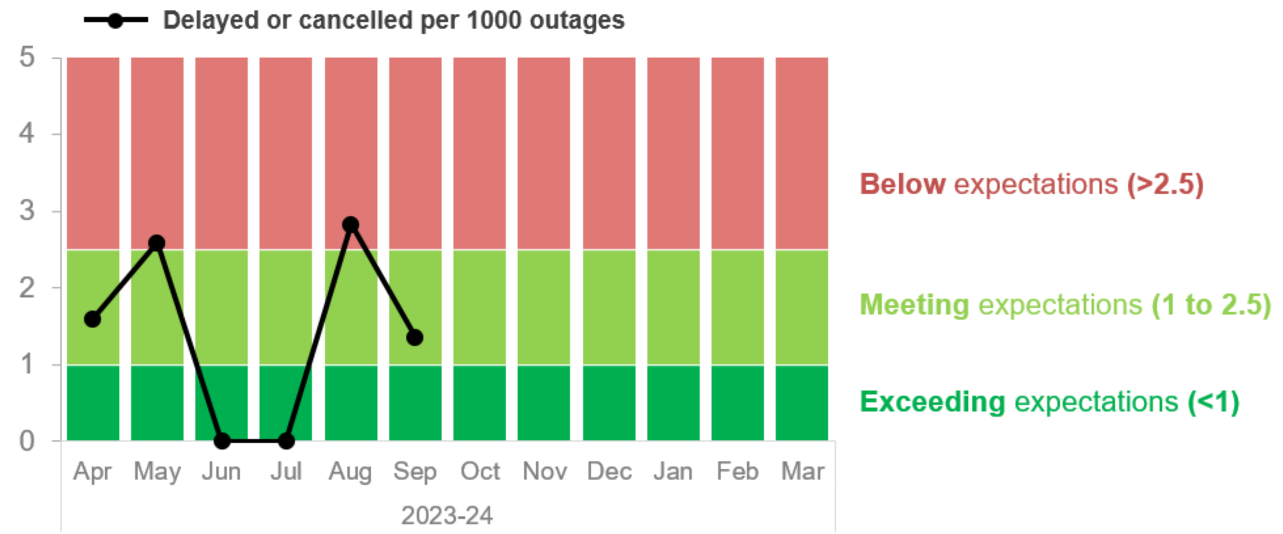


Table 4: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	624	739	645	644	706	734							4092
Outages delayed/cancelled due to ESO process failure	1	2	0	0	2	1							6
Number of outages delayed or cancelled per 1000 outages	1.6	2.6	0	0	2.8	1.4							1.5
Status	●	●	●	●	●	●							●

Performance benchmarks:

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

Supporting information

For September, we successfully released 734 outages. There was one delay and no cancellations due to an ESO process failure. The number of stoppages or delays per 1000 outages for September was 1.4, which is within the 'Meets Expectations' target of less than 2.5. The cumulative number of stoppages or delays per 1000 outages in 2023/24 is 1.5 which is within 'Meets Expectation's target.

The single event in September is summarised below:

The delay occurred due to the identification of unacceptable voltages for a particular fault due to the back-energisation of DNO equipment that was identified by our control room overnight prior to the outage release. The Planning team did assess the various faults as per the standard procedure, but it was identified retrospectively that the offline study used to simulate the various faults was incorrectly set up due to human error. Therefore, the problem was not identified in planning timescales and the appropriate engagement with the DNO did not happen. An Operational Learning Note (OLN) is being written to capture how to correctly set up the study to ensure the results are accurate. This would then prompt a discussion with the DNO/affected user on remedial action to resolve unacceptable voltages.

RRE 1E Transparency of operational decision making

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

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

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

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

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

The aim of this evidence is to highlight the efficient dispatch currently taking place within the BM while providing significant insight as to why actions are taken in the BM. Understanding the reasons behind actions 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.

We have been publishing the Dispatch Transparency dataset since March 2021, and it has sparked many conversations amongst market participants. As we continue to publish this dataset for BP2 we will also be providing additional narrative to help build trust by explaining:

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

September 2023-24 performance

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

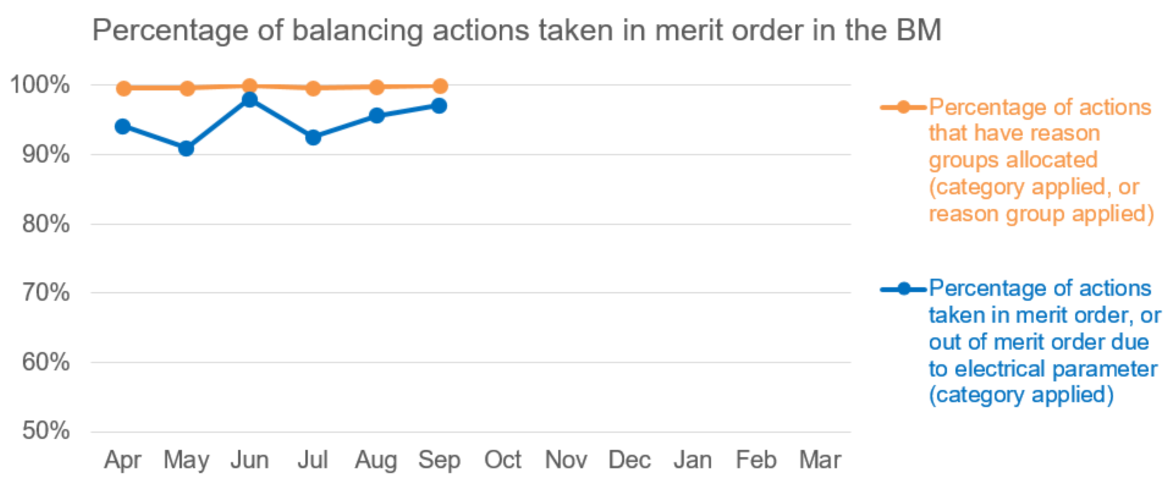


Table 5: Percentage of balancing actions taken outside of merit order in the BM

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

Supporting information

September performance

This month 97.1% of actions were either taken in merit order or taken out of merit order due to an electrical parameter. For the remaining actions, where possible, we allocate actions to reason groups for the purposes of our analysis. During September 2023, there were 44,663 BOAs (Bid Offer Acceptances) and of these, only 63 remain with no category or reason group identified, which is 0.1% of the total.

Other activities

We had intended this month’s report to include an overview of the activities planned for the remainder of this year to:

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

We have postponed presenting this overview to incorporate the outcomes of the ‘Enhancing Energy Storage in the BM’ event on 16 October. The objectives for this event include:

- Introduce an independent review of the current ESO Dispatch Transparency Dataset and obtain feedback for a common solution of what a new dataset should look like and what those metrics are.

Following the event, we are planning engagement with stakeholders to ensure we understand what change the wider industry would like to see in the way we report on Dispatch Transparency. Slides and Q&A from the this event, including the Q&A, will be published on our website at: Enhancing Energy Storage in the Balancing Mechanism | ESO (nationalgrideso.com). We are planning a follow-up event in December where you can hear the outputs and next steps from LCP Delta’s analysis. All industry feedback, together with the outputs from the independent review of the current dataset, will be used to inform our future activities including improving, or potentially replacing, the current Dispatch Transparency dataset.

RRE 1F Zero Carbon Operability Indicator

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, battery 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 BP2

Below we define the approximate maximum ZCO limit (using a reasonable approximation of likely operating conditions), the system can accommodate at the start and end of BP2, explaining which deliverables are critical to increasing the limit.

Table 6: Forecast maximum ZCO% after our operational actions

BP2 2023-25	Maximum ZCO limit	Calculation and rationale
Start of BP2 (Q1 2023-24)	**90% - 95%**	The maximum ZCO% achieved to date is 90%, set in January 2023. New frequency products and voltage and stability pathfinders are the main projects delivering increased ZCO% during the early part of BP2. The methodology for calculating ZCO% is consistent with BP1 and our continued delivery of projects and programmes increases the opportunity to operate the system at higher ZCO%.
End of BP2 (Q4 2024-25)	**95% - 100%**	We expect that our remaining projects, products and programmes will enable us to operate at 100% ZCO in 2025. Our operational strategy is set to deliver some key projects which will increase the maximum ZCO% over the BP2 period. These key deliverables are the deployment of our full suite of response and reserve products, voltage and stability pathfinders, further reduction of minimum inertia requirement via the Frequency Risk and Control methodology (FRCR) and improved tools for monitoring system inertia. These deliverables are either enabling zero carbon providers of ancillary services or increasing the window in which we can operate the system securely.

Part 2 – Regular reporting on actual ZCO

Every quarter we report 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, battery 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 Q2 was 98% on 28 September, settlement period 8.

However, for that period the final ZCO dropped to 80% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

The graphs further below show the underlying data by settlement period and highlight when the maximum monthly values occurred.

Table 7: six-month maximum zero carbon generation percentage by month (2023-24)

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	83.6%	90.7%	10 Apr / 36
May	79.6%	88.0%	4 May / 24
June	79.9%	92.3%	10 Jun / 33
July	83.9%	90.9%	3 Jul / 22
August	82.9%	96.0%	19 Aug / 29
September	89.1%	97.1%	24 Sep / 31

Note that the values can change between reporting cycles as the settlement data is updated by Elexon.

Figure 6: Maximum monthly ZCO% after ESO operational actions, versus ZCO provided by the market (during the settlement period when the maximum occurred) – two-year view

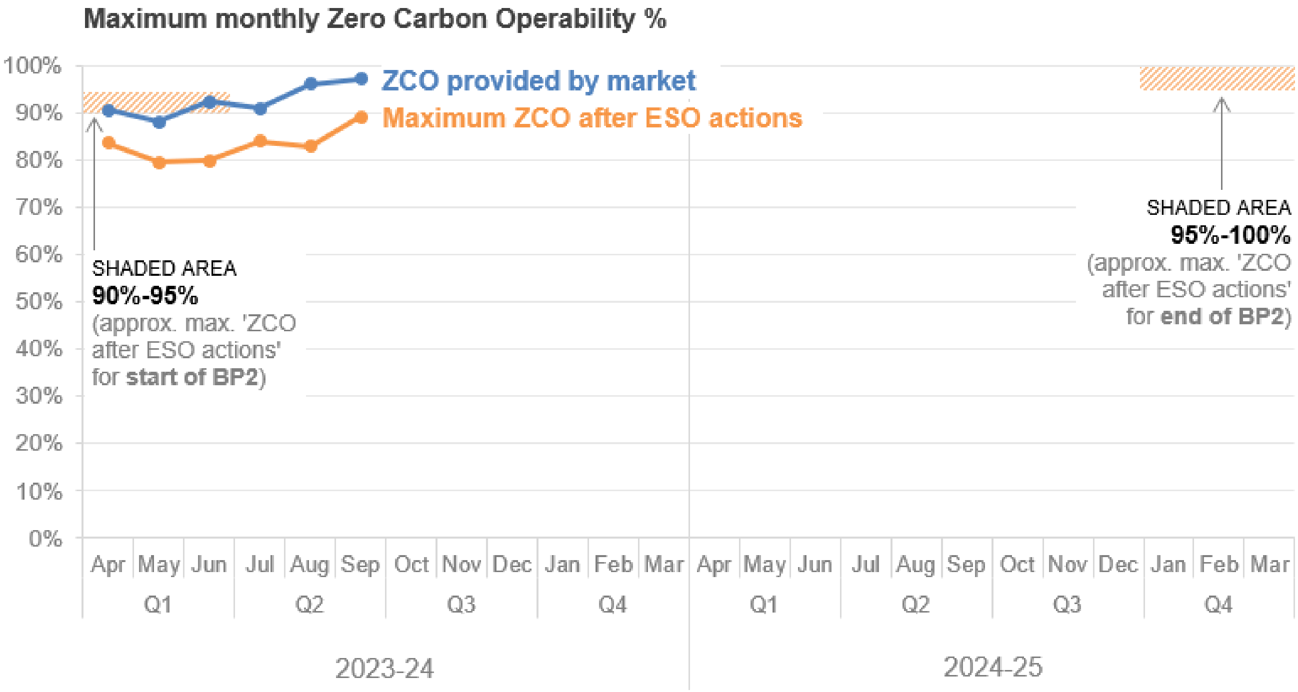
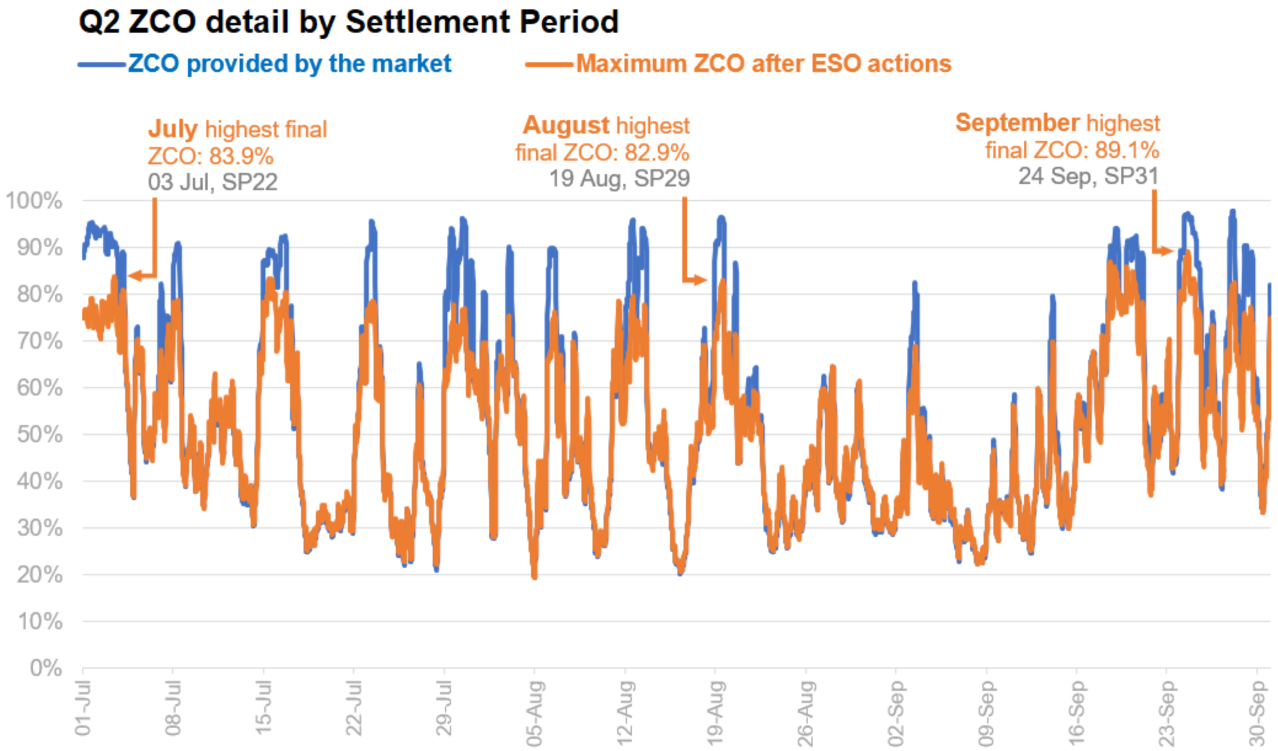


Figure 7: Q2 2023-24 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

Records have been broken again in the second quarter of BP2. Carbon intensity was at its lowest ever on 18 September at just 27g CO_2/kWh, and generation from Solar PV peaked again at 10.1GW on 7 July.

Every month in Q2 saw a minimum increase of 10% compared to 2022 (see table below) and 10% of all settlement periods in Q2 had a higher ZCO% than the highest ZCO% in Q2 last year; further evidence that our innovative approach to system operation and new ancillary service products are enabling the transition to net zero.

On all highest ZCO days during the quarter, the main factor for the ZCO% reduction was a need for synchronous generation to provide inertia and meet the minimum system inertia requirement. Inertia delivered by Stability Phase 3 contracts and our plans to reduce the minimum inertia requirement by 2025 will negate the need for these actions in future.

Areas where we have improved ZCO: On 19 August, the control room increased a boundary constraint limit avoiding 100MW of wind bids and mitigated further ZCO% reduction. Pump storage units were instructed to pump throughout the day for constraints; this also mitigated further ZCO% reduction. Pumps were used again on the 24 September to manage constraints, with the benefit of keeping the ZCO% high.

Highest final ZCO by month vs previous year

Quarter	Month	2022	2023	Difference
Q1	April	83.7%	83.6%	-0.2%
	May	78.5%	79.6%	1.1%
	June	76.7%	79.9%	3.2%
Q2	July	73.9%	83.9%	**10.0%**
	August	67.3%	82.9%	**15.6%**
	September	73.5%	89.1%	**15.6%**

RRE 1G Carbon intensity of ESO actions

This Regularly Reported Evidence (RRE) measures the difference between the carbon intensity of the combined Final Physical Notification (FPN) of machines in the Balancing Mechanism (BM) and the equivalent profile with balancing actions applied.

This takes account of both transmission and distribution connected generation and each fuel type has a Carbon Intensity in gCO2/kWh associated with it. For full details of the methodology please refer to the Carbon Intensity Balancing Actions Methodology document. The monthly data can also be accessed on the Data Portal here. Note that the generation mix measured by RRE 1F and RRE 1G differs.

It is often the case that balancing actions taken by the ESO for operability reasons increase the carbon intensity of the generation mix. More information about the ESO's operability challenges is provided in the Operability Strategy Report.

September 2023-24 performance

Figure 8: 2023-24 Average monthly gCO2/kWh of actions taken by the ESO (vs 2022-23)

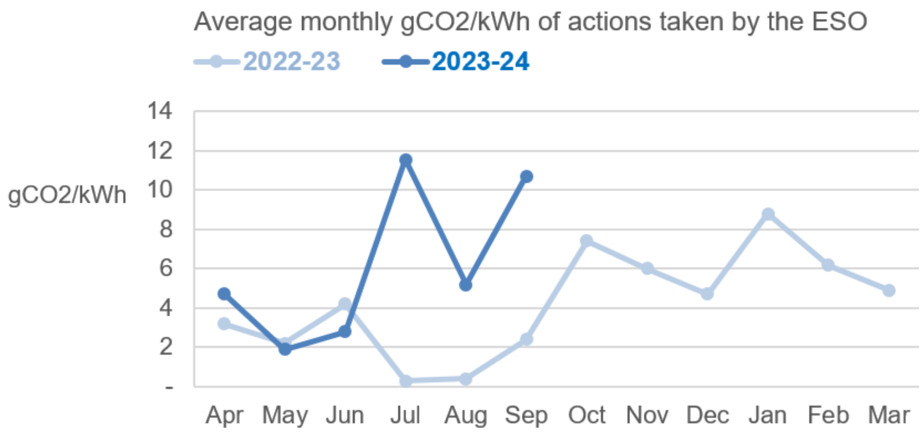


Table 8: Average monthly gCO2/kWh of actions taken by the ESO

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

Supporting information

In September 2023, the average carbon intensity of balancing actions was 10.7gCO2/kWh. This is 8.3g higher than Sept 2022 (which was 2.4gCO2/kWh).

Across the month, our actions reduced the carbon intensity in 25% of settlement periods.

The greatest impact of our actions on carbon intensity was seen on 3 September, raising the carbon intensity by 40g on average across the day (peaking at 80g in the morning). Synchronous units were required for most of the day for voltage, inertia and margin needs. Some units were also required until the Western HVDC link was returned to service and to cover a trip test. Up to 2.6GW of wind was constrained to manage Scottish constraints.

The lowest carbon intensity provided by the market was on the 24 September 12:30-13:00 (~9gCO2/kWh) with high wind (~19GW) and solar (~3.8GW) providing around 68% of the generation mix (after ESO actions). Additional synchronous units were required for voltage and inertia reasons raising the carbon intensity to ~41gCO2/kWh. Across the rest of the day, up to 5GW of wind was constrained in Scotland for both constraint and margin reasons. Two additional synchronous units were required for voltage, a further unit to cover a planned circuit trip and another six for system inertia. Additional pumping on pump storage and the economic use of batteries to manage constraints and downward margin mitigated further increase to carbon intensity.

RRE 1H Constraints Cost Savings from Collaboration with TOs

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.

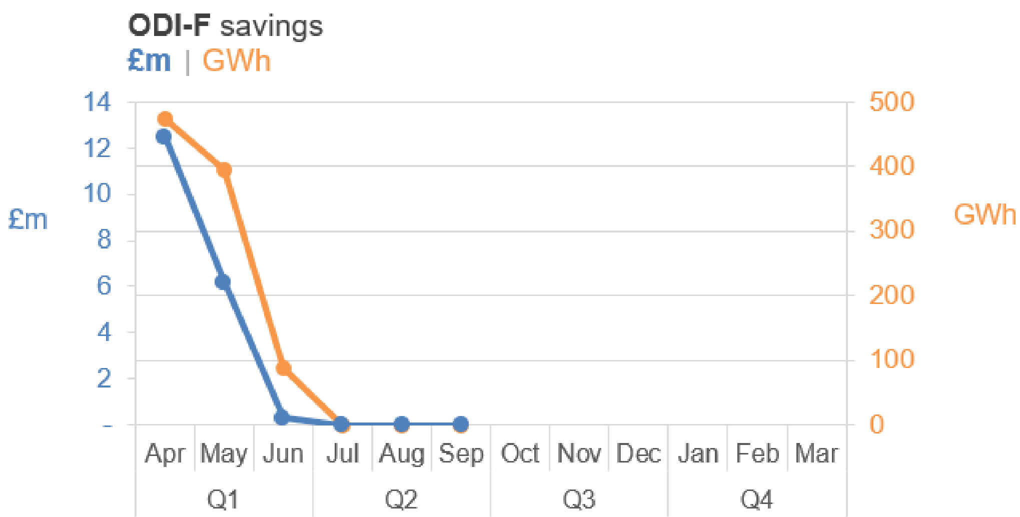
There are two ways the ESO can work with the TOs to minimise constraint costs. We will report on both for RRE 1H:

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 9: Estimated £m savings in avoided constraints costs (ODI-F) – 2023-24

(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 10: Estimated £m savings in avoided constraints costs (Other) – two-year view

(Estimated savings in GWh are also shown for context)

*Note **vertical axes scales** differ from the ODI-F graph above.*

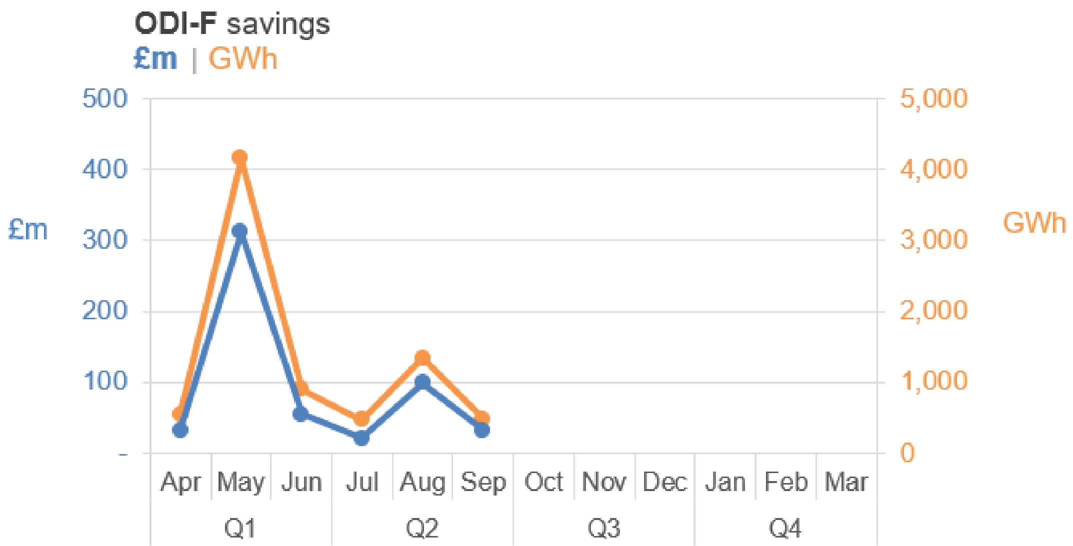


Table 9: Monthly estimated £m savings in avoided constraints costs (2023-24)

	ODI-F savings	**Other** savings	**ODI-F** savings	**Other** savings
	£m	£m	GWh	GWh
Apr	12.5	32.4	474.6	554.6
May	6.2	311.2	394.2	4163.0
Jun	0.3	54.4	87.6	903.7
Jul*	-	20.6	-	474.3
Aug*	-	99.1	-	1345.3
Sep*	-	32.4	-	485.1
Oct				
Nov				
Dec				
Jan				
Feb				
Mar				
YTD	**19.0**	**550.1**	**956.4**	**7926.0**

Note that figures from previous quarters may change as some savings are updated retrospectively with costs that were not available at the time that the activities were carried out.

Prices of £55 per MWh are used for conventional generation and £77 per MWh for renewable generation.

*For July to September the 11-4 applications result in a total Forecast cost saving of £29.6m (not shown in the table above). However, as a result of huge increase in the number of 11-4 applications over the last few months (we've already had as many applications in Q1 and Q2 as we did in the whole of 2022-23), we are still calculating the actual outturn savings for Q2, hence the dashes in Table 9 for this period. These will be updated in future quarterly reports.

Supporting information

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

The Network Access Planning (NAP) team has progressed and approved 13 enhanced service provisions from TO's through STCP 11.4 that provide constraint cost savings this quarter. These include:

- A thermal limit circuit enhancement was agreed with the TO, in the Northwest of England. This enhancement provided 87.6 GWh of energy saving and has been estimated to save £250k to the end consumer. This is ongoing and therefore has not been included in the savings for this quarter.
- A thermal enhancement was agreed for a circuit in the south of England for the duration of an outage on Bramley – Fleet 2. Unfortunately, the outage had to be recalled due to a fault on the system and so this enhancement could not be used. It is likely to be replanned for the future and the value for this work to finally be realised.
- An agreement was made via 11.4 to allow pre-stringing of towers to reduce the outage durations on key circuits around Manchester in the Northwest of England. These works reduced fault exposure costs by £650k and reduced constraint costs by £500k. Unfortunately, the TO delayed the outage and this work will not add value until this can be replanned. The 165.6 GWh of savings for this work has not been added to the saving made this quarter but will be added in the future when these works have been replanned.

So far this year, 2023-24 NAP has realised around **£19 million of constraint cost savings** through STCP 11.4. This is using a combination of cost estimations and calculated outturn costs for completed 11.4 opportunities only. Therefore, this may be subject to change as further outturn costs are calculated.

Other Savings (Customer Value Opportunities):

The Network Access Planning (NAP) team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded **43 instances this quarter** where our actions directly resulted in adding value to the end consumers, and our innovative ways of working facilitated increased generation capacity to the 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, and facilitating alternative solutions for long outages that impact customer, and many more.

Some examples of these instances for quarter 2, include:

- In July, running arrangement optimisations were made at Drakelow 400kV substation in the North Midlands of England. These optimisations alleviated overloads on surrounding circuits during a bar outage at the site. This allowed for higher limits to be achieved through the surrounding circuits. A total of 124,800 MWh of energy constraint was saved via this action, equating to £4 million saved for the end consumer.
- In August, we worked closely with SPT to arrange for optimisations of outage placement for key maintenance works around the Western Link HVDC converter station at Hunterston in the south of Scotland. These alignments removed a 650MW drop for 12 days on the Western Link. This saved 187 GWh on B6 boundary constraints. The B6 boundary is one of the most expensive boundaries in the UK. This saving is equivalent to £14m to the end consumer, or the energy required to power almost 16,000 UK homes for a year.
- At the end of August, national and regional teams at the ESO, working together with the current year planners at SSEN-T, spotted an opportunity to align works in the northeast of Scotland impacting export capacity for Peterhead generation. Both outages individually would reduce the export from Peterhead by 500 MW, but taken together had no additional impact. By nesting these outages in the same window, we were able to provide 500MW of conventional generation saving

that did not need to be constrained at cost and then bought back on elsewhere in the country at further cost to the end consumer. This equates to a total of 256 GWh across the duration of the outage around £19.2 million saved. 256 GWh is equivalent to the energy consumed by more than 21,000 UK homes in a year.

These and many more represent a total of **7.9 TWh (approximately £550m)** of extra generation capacity, which would have otherwise been constrained at a cost to the consumer. This is the same power required for 650,000 UK homes.

A note on updated costings: the conversion from MWh saving to £ saved is now done assuming 30% effectiveness of all optimisations and using bid off costs plus replacement energy costs on the current system as £120/ MWh for conventional generation and £250/ MWh for renewable generation.

Therefore, wind-based constraint enhancements are converted at £75/ MWh, gas-based constraint enhancements are converted at £36/ MWh, and demand improvements are converted at £50/ MWh.

RRE 1I Security of Supply

This Regularly Reported Evidence (RRE) shows when the frequency of the electricity transmission system deviates more than ± 0.3Hz away from 50 Hz for more than 60 seconds, and where voltages are outside statutory limits. On a monthly basis we report instances where:

- The frequency is more than ± 0.5Hz away from 50 Hz for more than 60 seconds
- The frequency was 0.3Hz - 0.5Hz away from 50Hz for more than 60 seconds.
- There is a voltage excursion outside statutory limits. For nominal voltages of 132kV and above, a voltage excursion is defined as the voltage being more than 10% away from the nominal voltage for more than 15 minutes, although a stricter limit of 5% is applied for where voltages exceed 400kV.

For context, the **Frequency Risk and Control Report** defines the appropriate balance between cost and risk, and sets out tabulated risks of frequency deviation as below, where 'f' represents frequency:

Deviation (Hz)	Duration	Likelihood
$f > 50.5$	Any	1-in-1100 years
$49.2 \leq f < 49.5$	up to 60 seconds	2 times per year
$48.8 < f < 49.2$	Any	1-in-22 years
$47.75 < f \leq 48.8$	Any	1-in-270 years

At the end of the year, we will report on frequency deviations with respect to the above limits and communicate any plans for future changes to the methodology.

September 2023-24 performance

Table 10: Frequency and voltage excursions (2023-24)

	2023-24											
	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0						
Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	0	1	0	0	0						
Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0						

Supporting information

September performance

There were no reportable voltage or frequency excursions in September.

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

RRE 1J CNI Outages

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

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

September 2023-24 performance

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

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

Table 12: 2023-24 Planned CNI System Outages (Number and length of each outage)

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

Supporting information

September performance

In September 2023 there was one planned CNI system outage. The outage was part of regular planned maintenance activities on the BM production systems, and impacted the key BM Suite components used for scheduling and dispatch of generation.

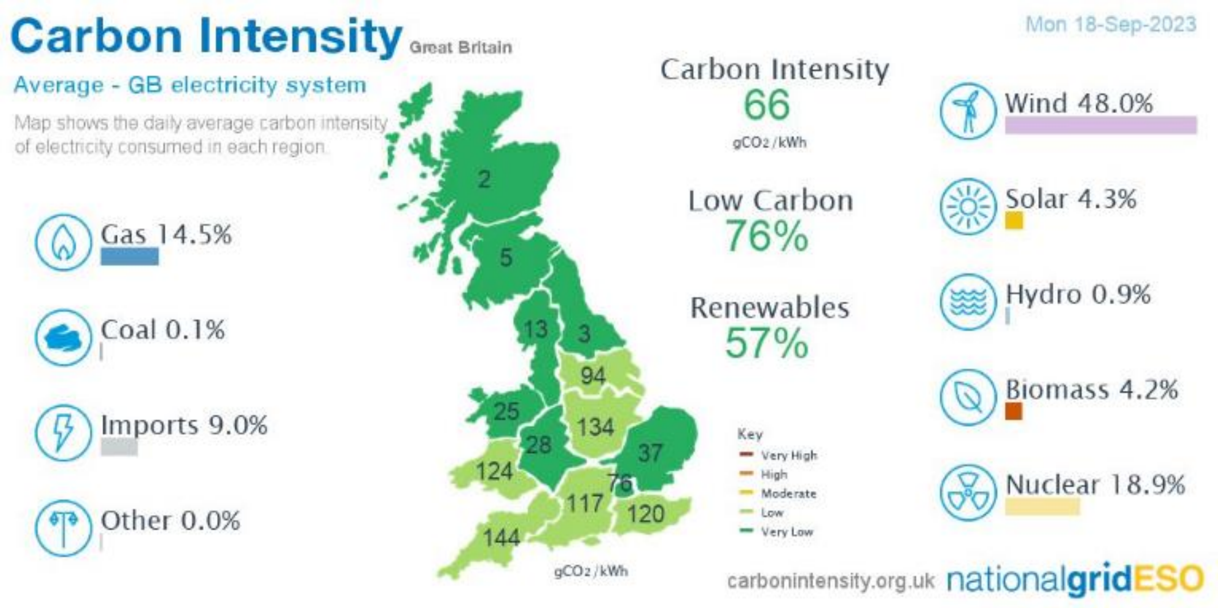
There were no other planned outages during September.

There were no unplanned outages during September.

Notable events during September 2023

New low carbon intensity record

On 18 September at 2pm, we achieved a new low carbon intensity record of 27g/kWh, beating the previous record set earlier this year on 10 April of 33g/kWh. This is a great step towards our commitment of delivering periods of zero-carbon operations by 2025.



Winter Outlook 2023/24 Published

On 28 September we published our Winter Outlook, providing our views on security of UK electricity supply for Winter 2023/24. We publish our Winter Outlook every Autumn and we also publish our suite of Outlook publications across the year to provide information and transparency to the industry. More information on Winter Outlook can be found here.

This year, our modelling forecasts an operational de-rated margin of 4.4 GW or 7.4%. This de-rated margin is the minimum excess available electricity that is needed to operate the network safely. For 2023/24 it's slightly higher than last year's 3.7GW and remains broadly in line with recent winters.

These slightly improved margins reflect how the energy landscape is changing across the wider British and European energy markets, compared to 12 months ago. Both European gas storage and French Nuclear power have greater availability than last year, helping to support electricity and gas flows across both Europe and to Great Britain.

Across last winter, the energy markets across Europe performed as expected; ESO's teams worked with their colleagues across European electricity systems to help manage consumer demand across the period. They will continue to work closely with neighbouring Transmission System Operators (TSOs) in Europe as we head towards this winter.

Given the continued uncertainty presented by the invasion of Ukraine by Russia, we know that it's also important that we continue as usual to prepare and plan for a wide range of eventualities. So we've also announced that we are reintroducing the innovative Demand Flexibility Service this winter, to incentivise customers to reduce consumption at periods when margins are tightest.

Small-scale aggregated assets: Live Balancing Mechanism Trial

In conjunction with Power Responsive, we have started a trial to examine small scale assets operating in the Balancing Mechanism (BM). This trial allows a temporary relaxation of the existing operational metering standards, for three months for new assets for a limited volume (50MW total, 10MW per company) with the aimed completion date of April 2024. All other market entry obligations will remain the same.

This is part of a set of ESO activities examining the feasibility of enabling small scale aggregated assets, such as Electric Vehicles, to participate in the BM. This is to address concerns from these potential providers that existing operational metering standard are cost prohibitive and act as a barrier to participation.

The objectives of the trial are:

- **Technical feasibility** – Review the capability of assets operating in BM framework (e.g. accuracy of data submissions and ability to respond to instructions)
- **Evaluate benefits** – Additional flexibility in the BM and impact on balancing costs.
- **Implications -** Assess impacts and risks of aggregated smaller-scale assets operating in the BM across existing capabilities.

The first participant went live on 14 September, with other participants planning to participate over the coming months. We have started to see BM instructions and are building up a set of evidence to determine next steps following the trial.

Role 2 (Market developments and transactions)

ESO

Metric 2Ai Phase-out of non-competitive balancing services

This metric measures the percentage of services procured by the ESO that are procured on a non-competitive basis. For the purpose of this metric, we consider a 'non-competitive' service to be either a bilateral contract or a service with significant barriers to entry. It excludes SO-SO trades, which are trades made between system operators of connected countries. These are used to determine the direction of electricity flow over interconnectors. The volumes reported in this metric are those delivered within the time period.

There are benchmarks for the following categories: Frequency Response (FR) and Reserve, Reactive Power, and Constraints.

Benchmarks are set based on the ESO's current and projected procurement for each of these services:

Category	Benchmark	Assumptions applied in BP2 benchmark
FR and Reserve	Year 1: 25% Year 2: 20%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • Reserve will continue to be procured competitively until the implementation of new reserve services
Reactive power	Year 1: 90% Year 2: 90%	• Historical data was analysed from the previous reporting period (BP1) and no uplift applied for the benchmark • Competitive procurement of Reactive Power through Market mechanisms will be understood later in 2023 – through the Reactive Power Market Reform. • There will continue to be specific regional requirements, and these will be procured through market mechanisms where feasible.
Constraints	Year 1: 65% Year 2: 55%	• Historical data was analysed from the previous reporting period (BP1) and uplift of 5% applied for the benchmark • B6 Commercial Intertrip service was the first Constraint service to be delivered competitively. More will be delivered through market mechanisms in BP2, such as Constrain Management Intertrip Service (EC5 CMIS) and Local Constraint Market (LCM)

The non-competitive percentage is calculated on a volume basis, which is measured in MWs, with the exception of Reactive Power which is measured in MVAr.

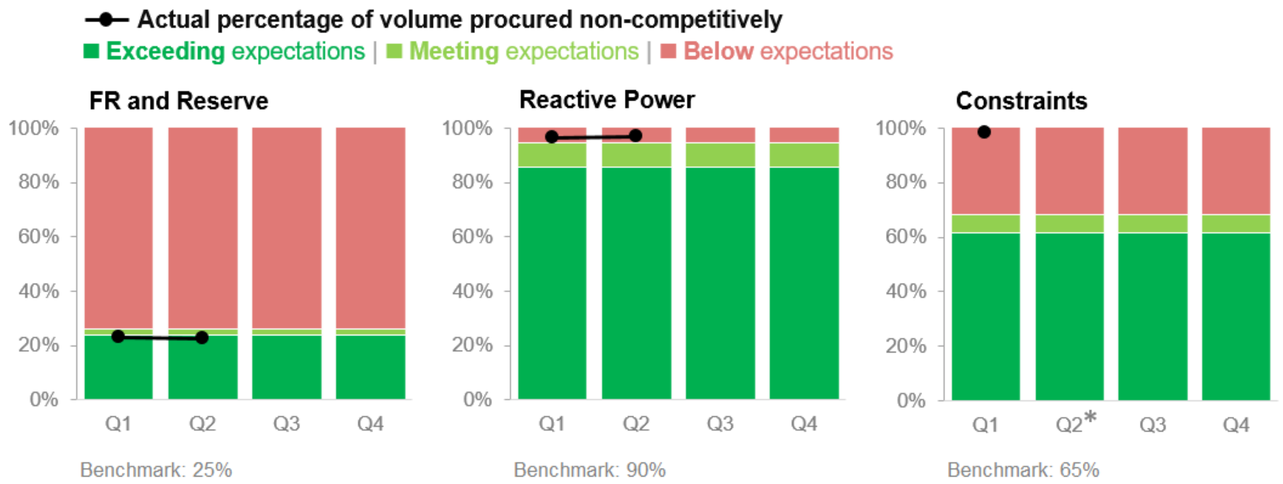
These expectations are set for the current suite of products and may be revised if new products are introduced.

Category	Services procured **competitively**	Services procured **non-competitively**
Frequency Response	• FFR (Firm Frequency Response) Secondary, High and Static • Dynamic Containment Low and High • Dynamic Moderation Low and High • Dynamic Regulation Low and High	• Mandatory Frequency Response (Primary, Secondary and High) • Enhanced Frequency Response • Fast Start
Reserve	• Day Ahead STOR (Short Term Operating Reserve)	• Long Term STOR • Optional Fast Reserve
Reactive Power	• Mersey Reactive Power Pathfinder • Pennines Pathfinder	• Reactive • Mandatory Reactive Lead & Lag • Stability Reactive Lead & Lag • Reactive Sync Comp, Comp Lead and Comp Lag • Inertia (Stability)
Constraints	• B6 Intertrip	• Super SEL (Stable Export Limit) (Footroom) • Strike Price

Overall performance – All services

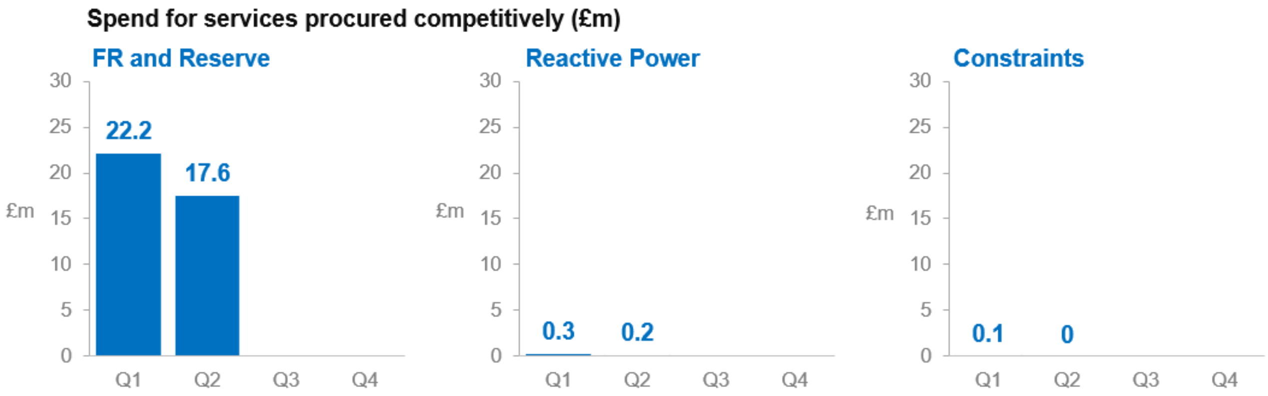
Q2 2023-24 performance

Figure 11: Percentage of volume procured non-competitively vs benchmark



Constraints Q2* - as no volume was procured in Q2, there is no figure for percentage of volume procured non-competitively, and no point on the graph. Therefore, there is also no status for Q2.

Figure 12: Quarterly competitive spend by service



SO-SO trades made during Q2

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO. EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CBB.

Trades for Q1 totalled £0.06m consisting of 2 trades on Moyle interconnector.

Trades for Q2 totalled £0.2m consisting of 3 trades, 2 on the Moyle Interconnector and one on the IFA-1 Interconnector.

Data content Information:	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

1. Frequency Response and Reserve

Q2 2023-24 performance

Table 13: Frequency Response and Reserve percentage of services procured on a non-competitive basis, and spend.

Frequency Response & Reserve		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWh	13742	10789		
	Volume procured non-competitively	GWh	3154	2431		
	Percentage of volume procured non-competitively	%	**23%**	**23%**		
	Year 1 benchmark	%	25%	25%	25%	25%
	Status	n/a	●	●		
Spend	Total spend	£m	46.7	36.8		
	Spend for volume procured competitively	£m	22.2	17.6	24.5	19.2
	Spend for volume procured non-competitively	£m	24.5	19.2		

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 is 20%

Supporting information

In Q2, 23% of Frequency Response and Reserve volume was procured non-competitively compared to the benchmark of 25%, and therefore exceeding expectations.

With the growth in response and reserve competitive markets we are able to procure more of our requirements at the day ahead so have less reliance on non-competitive procured services. As more reserve services are introduced to day-ahead procurement we expect to see further reductions in the Frequency Response and Reserve volumes that are procured non-competitively. For Long Term STOR, we remain committed to the legacy ~ 400MW volume of contracts which expire in April 2025. This volume will then be replaced by volumes procured at day ahead through the new reserve products.

2. Reactive Power

Q2 2023-24 performance

Table 14: Reactive Power percentage of services procured on a non-competitive basis, and spend.

Reactive Power		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GVARh	15,650	10,844		
	Volume procured non-competitively	GVARh	15,126	10,487		
	Percentage of volume procured non-competitively	%	**97%**	**97%**		
	Year 1 benchmark	%	90%	90%	90%	90%
	Status	n/a	●	●		
Spend*	Total spend	£m	76.6	46.2		
	Spend for volume procured competitively	£m	0.3	0.2		
	Spend for volume procured non-competitively	£m	76.3	45.9		

*Rounding: Spend figures in £m are rounded to the nearest 1 decimal place, therefore Total spend may differ slightly from the sum of competitive and non-competitive spend.

Performance benchmarks:
- ● **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- ● **Meeting expectations:** within ±5% of the annual procurement benchmark
- ● **Below expectations:** 5% or more higher than the annual procurement benchmark

The benchmark for Year 2 remains at 90%

Supporting information

In Q2 97% of Reactive Power volume was procured non-competitively compared to the benchmark of 90% and therefore below expectations. The benchmark was established late in the BP1 period, on the expectation that by BP2 we would have a Reactive Market in place. The development of that market was postponed in 2022 and has restarted in May 2023. This remains unchanged from Q1.

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 percentage of services delivered by non-competitive means in this quarter is similar to the previous quarter and will be in future quarters of 2023/24 as we re-establish the Reactive Power future market. We are now working on assessing the feasibility of implementing the proposed market design with a commitment to sharing a plan for how this will be implemented by the end of 2023.

The launch of the short- and long-term Voltage Pathfinders previously has proven that distribution network providers can also be effective to meet a transmission need. The long-term Mersey Pathfinder awarded two contracts to meet a need in this region: the Peak Gen shunt reactor service went live in Q1 2022-23 and the Zenobe Battery live in Q4 2022-23. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25 which will decrease the percentage of reactive power services procured and utilised through non-competitive means.

Unlike Q1, there was no need for any short-term requirements in Q2.

3. Constraints

Q2 2023-24 performance

Table 15: Constraints percentage of services procured on a non-competitive basis and spend.

Constraints		Unit	Q1	Q2	Q3	Q4
Volume	Total volume procured	GWh	158	0		
	Volume procured non-competitively	GWh	155	0		
	Percentage of volume procured non-competitively	%	98%	N/A		
	Year 1 benchmark	%	65%	65%	65%	65%
	Status	n/a	●	N/A		
Spend	Total spend	£m	4.9	0		
	Spend for volume procured competitively	£m	0.1	0		
	Spend for volume procured non-competitively	£m	4.8	0		

Performance benchmarks:

- **Exceeding expectations:** 5% or more lower than annual procurement benchmark
- **Meeting expectations:** within ±5% of the annual procurement benchmark
- **Below expectations:** 5 or more higher than the annual procurement benchmark

The benchmark for Year 2 is 55%

Supporting information

In Q2, no constraint volume was procured due to low wind and no requirement to call upon the service. Therefore, there is no status applicable for Q2. Year-to-date we remain below expectations, with 98% of volume procured non-competitively, compared to the benchmark of 65%.

In BP2 we expected to be able to utilise the intertrip services more frequently across the B6 and future constraint boundaries if economic to do so and greater market liquidity. We expect greater utilisation of this service in Q3 and Q4 when wind is generally higher and shall continue to assess opportunities to use this service across the B6 boundary (dependant on system conditions) and will look to extend this to the East Anglia EC5 CMIS service when it becomes live.

No Strike Price was procured throughout the quarter.

Super SEL has now been moved to Reserve Services.

Metric 2X Day-ahead procurement

This metric measures the percentage of balancing services procured at no earlier than the day-ahead stage, i.e. those procured at day-ahead or closer to real time. We report on total contracted volumes (mandatory and tendered) in megawatts (MWs). Expectations are set for all relevant services that are currently procured by the ESO and may be revised if new products are introduced.

Benchmarks are set based on expected product expirations, and expectations for new procurement volumes:

Note that in line with the terms of a derogation from the requirements of Article 6(9) of the Electricity Regulation, the ESO is required to procure at least 30% of services no earlier than day-ahead stage

Whilst the ESO set out the daily requirements for Day ahead procurement, when these requirements are not met through competitive day ahead tendering the outstanding requirement could be met through other means such as bi lateral agreements and mandatory markets.

The following services are included in the figures for this metric:

Day ahead: Short-Term Operating Reserve (STOR), Dynamic Containment, Dynamic Moderation, Dynamic Regulation, Static Firm Frequency Response

Non-day ahead: Firm Frequency Response Monthly, Mandatory Frequency Response, Long Term STOR

Services newly introduced during BP2 should only be included in this metric if they displace those procured earlier than day-ahead.

Q2 2023-24 performance

Figure 13: Quarterly percentage of balancing services procured at no earlier than day-ahead

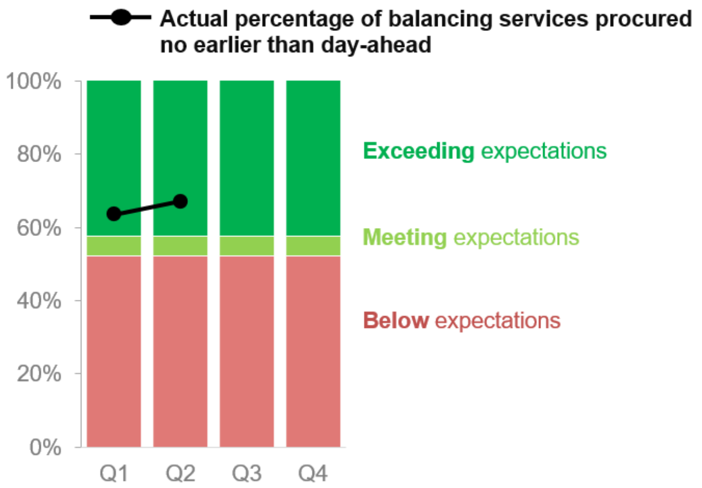


Table 16: Quarterly percentage of balancing services procured at no earlier than day-ahead

	Unit	Q1	Q2	Q3	Q4
Total volume of balancing services procured	MW	12,447	12,604		
Volume procured no earlier than day-ahead	MW	7,910	8,464		
Actual % of balancing services procured no earlier than day-ahead (i.e. day-ahead or closer to real time)	%	64%	67%		
Benchmark	%	55%	55%	55%	55%
Status	n/a	●	●		

Performance benchmarks:

- **Exceeding expectations:** 5% or more higher than annual day-ahead procurement benchmark
- **Meeting expectations:** within ±5% of the annual day-ahead procurement benchmark
- **Below expectations:** 5% or more lower than the annual day-ahead procurement benchmark

For year 2, the benchmark increases to 80%

Data content Information:	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

In Q2 67% of balancing services volume was procured no earlier than day ahead, compared to the benchmark of 55%, and therefore exceeding expectations.

The exceeding expectations performance for day ahead procurement of services is due to several factors across the markets. Over the past 12 months the response and reserve markets have matured, resulting in greater market liquidity and greater competition. Reducing volumes in non-day ahead service such as Dynamic Firm Frequency response as it is being phased out and these volumes are going into services procured at day ahead.

Going forward we would expect to see this performance increase as legacy services are fully phased out and new services go live.

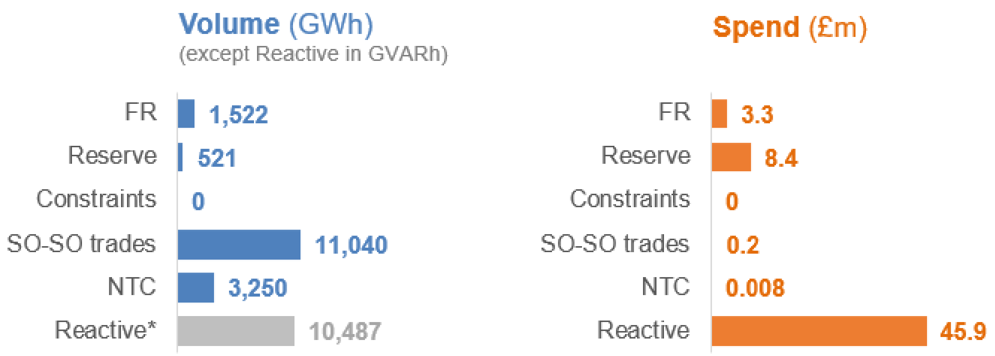
RRE 2Aii Balancing services procured in a non-competitive manner

This Regularly Reported Evidence measures the volume and spend for non-competitive services for contracts. For the purpose of this metric, we have included volumes where the decision to instruct non-competitive services is made after 31 March 2023, even if the contract terms were signed before (e.g. Mandatory Frequency Response). Figures are reported in GWh/GVARh for the contracted month, which is calculated as the contracted volume in MW multiplied by the number of contracted hours.

Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded. However, all SO-SO trades and NTC application, as well as any other non-competitively procured services with contract award after this date, are included.

Q2 2023-24 performance

Figure 14: Volume and spend for non-competitive services for contracts



*Reactive volume is measured in GVARh and is not directly comparable to the other services measured in GWh but is included in the graph with this caveat.

Table 17: Volume and spend for non-competitive services

	Service	Unit	Q1	Q2	Q3	Q4
VOLUME	Frequency Response****	GWh	1,895	1,522		
	Reserve****	GWh	506	521		
	Constraints***	GWh	155	0		
	SO-SO trades	GWh	10,920	11,040		
	Net Transfer Capacity (NTC)	GWh	5,242	3,250		
	Total Volume in GWH	GWh	**18,718**	**16,333**		
	Reactive (in GVARh)	GVARh	14,644	10,487		
SPEND	Frequency Response	£m	4.0	3.3		
	Reserve -	£m	8.7	8.4		
	Constraints	£m	4.8	0		
	SO-SO trades *	£m	0.06	0.2		
	Net Transfer Capacity (NTC)**	£m	0	0.008		
	Reactive	£m	76.1	45.9		
	Total spend	£m	**93.6**	**57.8**		

*SO-SO trades, trade volumes and costs for services provided to the ESO by another country's system operator have been included. Services provided by ESO to another country's System Operator are excluded.

**NTC cost has been updated for Q1 to show payments to provider only – this logic to be used going forward

***For Q2 - Super SEL category has moved from Constraints to Reserve

****Total non-competitive procurement for Frequency Response and Reserve in RRE 2Aii will not align with volume stated in Metric 2Ai. This is because Legacy Short-Term Operating Reserve (STOR) and Enhanced Frequency Response (EFR) contracts are excluded from RRE 2Aii as per the agreed methodology.

Data content Information:	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Supporting information

Frequency Response

The volume of non-competitive services procured in Frequency Response is Mandatory Frequency Response (MFR). MFR is used as an element of our response holding that can be instructed within operational timescales. We are considering alternatives to MFR to reduce this volume in future.

Reserve

This volume of non-competitive Reserve is made up of the intra-day Optional Fast Reserve product, where prices for the service can be updated by providers per Settlement Period close to real-time. The Optional Fast Reserve product will be phased out with the introduction of the new day ahead procured reserve products as they are introduced through 2024.

Optional Fast Reserve is used for short-term frequency management outside contracted fast reserve windows e.g., periods where wind may have dropped unexpectedly or demand has increased more than anticipated. Note that day ahead procured STOR is to replace the largest loss and thus utilisation should always be quite low.

Super SEL, which is now included as a Reserve service, is an active but optional contract that a number of generators can provide as a backup to other solutions. Super SEL has not been utilised since early 2022 and so we have reported 0GWh in this metric to reflect utilisation. We have previously reported the contract values and not actual utilisation.

Constraints

There were no arming instructions throughout Q2 due to low wind and no requirement to call upon the service.

Additionally, no Strike price contracts were procured in Q2.

SO-SO Trades

Historically SO-SO Trades were available to the ESO across the IFA & IFA2 , Nemo Link, EWIC & Moyle Interconnectors. Since the introduction of hourly gates on IFA, IFA2 & Nemo Link, the current required notice period is longer than the hourly gates provide, this service can no longer be used by the ESO.

EWIC & Moyle Interconnectors enable SO-SO trades via Cross Border Balancing (CBB) and Coordinated Third Party Trading (CTPT) with EirGrid and SONI. The ESO does not trade via 3rd Parties and therefore only has access to CCB.

The volume of available SO-SO trades is high compared to payment, the service was only utilised twice in Q2 with payment only made upon utilisation and not availability.

Net Transfer Capacity (NTC)

A capacity management process is used to ensure secure system operation for both Interconnectors and onshore TSOs. This process can result in the reduction in capacity through the application of a Net Transfer Capacity (NTC) and this reduction is defined as a non-frequency ancillary service.

Standard Licence Condition C28 requires that we procure non-frequency balancing services using market-based procedures. NTC is not procured through market-based procedures and therefore requires a derogation from this requirement. The procurement of NTC cannot be market-based due to technical parameters and the fact that alternative actions are not sufficient or economically efficient.

On 28 September, Ofgem granted us a derogation against C28 for NTCs until 30 September 2026. This follows a request we sent to Ofgem to extend this derogation in August. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our Control Room certainty that they can use this vital tool when required for system security over the coming years.

NTC's are our only way of guaranteeing system security in real time. As a result, they are as near to real-time calculated values as the market structure allows. Any restrictions are based on the forecast system conditions for that particular real-time period and are reflective of the limits of GB system security.

RRE 2B Diversity of Service Providers

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 megawatts (MWs) or megavolt amperes of reactive power (MVARs).

There are four services we report on:

- Frequency Response (MFR, sFFR, dFFR, DC, DM, DR, FFR Auction, EFR)
- 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.

Methodology

Product		Methodology
Frequency Response	Mandatory Frequency Response (MFR)	We report on contracted volumes for every unit. Figures only apply to a single day, not the whole month. For example, a 20MW MFR contract is only recorded as 20MW in the report, not as 600 MW (20MW x 30days).
	Static Firm Frequency Response (sFFR)	We report on the highest volume for each unit that has contracted for a particular service block for the relevant month. The sum of those values is presented in the report.
	Dynamic Firm Frequency Response (dFFR)	
	Dynamic Containment (DC)	We report on the highest volume for each unit that has been contracted for a particular Electricity Forward Assessment (EFA) block for the relevant month. The sum of those values is presented in the report.
	Dynamic Moderation (DM)	
	Dynamic Regulation (DR)	
	Enhanced Frequency Response (EFR)	We report on contracted MW. This will not change from month to month unless a contract ends.
Reserve	Short Term Operating Reserve (STOR)	We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.
	Super SEL (Footroom)	We report on contracted volumes for all contracts that are live for any part of the month.
	Fast Reserve	We report on contracted volumes. We record the highest available volume for each unit for each month. Available volumes can change throughout the month for a unit. For example, a unit can be available at 60MW for 29 days in a month, and at 70MW for 1 day of the same month.
	Quick Reserve	We report on the highest volume for each unit that has been contracted for a particular service window for the relevant month. The sum of those values is presented in the report.
	Slow Reserve	
Reactive	Mandatory Reactive	We report on contracted volumes for every unit. Figures only apply to a single day and not the whole month. For example, a 20MW Reactive contract is only recorded as 20MW in the report, not as 600MW (20MW x 30days).
	Stability Reactive	
	Synchronous Compensation	

	Pennine Pathfinder	
Constraints	Strike Price	We report on contracted volumes for all contracts that are live for any part of the month. Some are live for the whole month whereas others are live for part of the month. The highest available volume on a specific day for each unit for the relevant month is captured. The sum of those values is what we present in the monthly report.
	B6 Intertrip	

Firm Frequency Response Auction – this service is excluded as it ended in 2021-22.

ℹ	**Data content Information:**	Data consists of final settlement data for first 2 months of the most recent quarter with 3rd month to be provided within the next submission of the report.

Figure 15: Total contracted volumes by service type for Q2

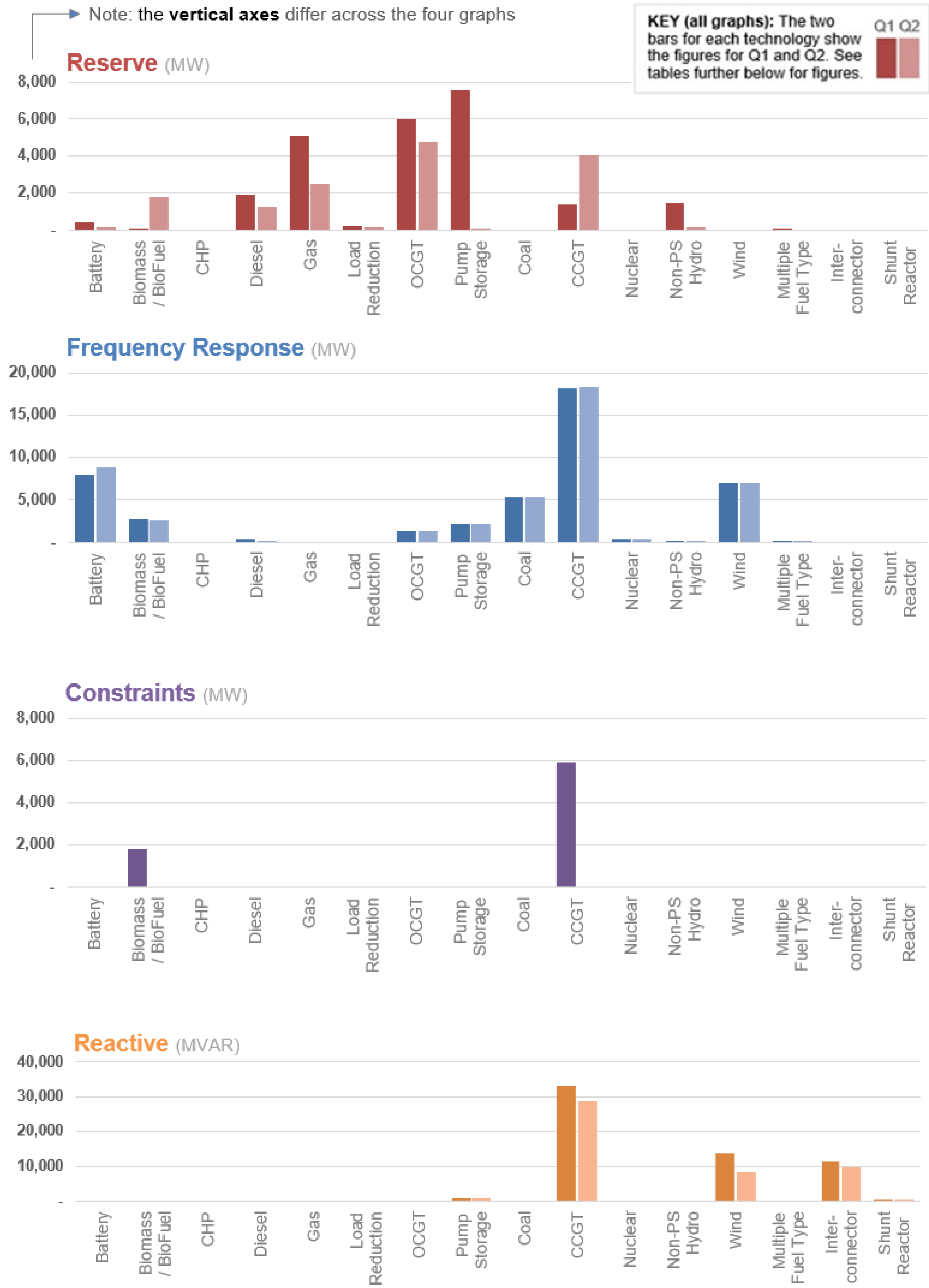


Table 18: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Q1	Q2
Total	8,017	8,022	8,022	5,038	5,105	4,793	24,062	14,936
Battery	134	134	134	40	24	88	401	152
Biomass/BioFuel	19	19	19	595	595	595	58	1,785
CHP	-	-	-	-	-	-	-	-
Diesel	628	627	627	426	421	423	1,882	1,270
Gas	1,690	1,691	1,691	910	831	773	5,073	2,514
Load Reduction	70	70	70	54	55	52	210	161
OCGT	2,001	2,003	2,003	1,497	1,762	1,485	6,008	4,744
Pump Storage	2,516	2,519	2,519	100	-	-	7,554	100
Coal	-	-	-	-	-	-	-	-
CCGT	465	466	466	1,416	1,417	1,227	1,397	4,060
Nuclear	-	-	-	-	-	-	-	-
Non-PS Hydro	490	490	490	-	-	150	1,470	150
Wind	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	9	-
Interconnector	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-

Frequency Response

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Q1	Q2
Total	15,161	15,436	15,203	15,501	15,324	15,467	45,800	46,292
Battery	2,596	2,767	2,695	3,017	2,820	2,956	8,058	8,793
Biomass/BioFuel	957	937	837	837	837	837	2,731	2,511
CHP	-	-	-	-	-	-	-	-
Diesel	112	112	56	36	56	56	280	148
Gas	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-
OCGT	443	443	443	443	443	443	1,329	1,329
Pump Storage	728	728	728	728	728	728	2,184	2,184
Coal	1,782	1,782	1,782	1,782	1,782	1,782	5,346	5,346
CCGT	6,024	6,148	6,148	6,148	6,148	6,155	18,320	18,451
Nuclear	92	92	92	92	92	92	276	276
Non-PS Hydro	70	70	70	70	70	70	210	210
Wind	2,343	2,343	2,343	2,343	2,343	2,343	7,029	7,029
Multiple Fuel Type	14	14	9	5	5	5	37	15
Interconnector	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-

Constraints

MWs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Q1	Q2
Total	2,300	3,605	1,795	-	-	-	7,700	-
Battery	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	-	-	-	1,785	-
CHP	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-
CCGT	1,705	3,010	1,200	-	-	-	5,915	-
Nuclear	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-
Wind	-	-	-	-	-	-	-	-
Multiple Fuel Type	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-
Shunt Reactor	-	-	-	-	-	-	-	-

Reactive

MVARs	Apr-23	May-23	Jun-23	Jul-23	Aug-23	Sep-23	Q1	Q2
Total	19,921	19,921	19,921	16,174	16,174	16,174	59,763	48,522
Battery	32	32	32	16	16	16	96	48
Biomass / BioFuel	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-
Pump Storage	235	235	235	235	235	235	705	705
Coal	-	-	-	-	-	-	-	-
CCGT	11,021	11,021	11,021	9,579	9,579	9,579	33,063	28,737
Nuclear	-	-	-	-	-	-	-	-
Non-PS Hydro	93	93	93	72	72	72	279	216
Wind	4,573	4,573	4,573	2,813	2,813	2,813	13,719	8,439
Multiple Fuel Type	-	-	-	-	-	-	-	-
Interconnector	3,767	3,767	3,767	3,259	3,259	3,259	11,301	9,777
Shunt Reactor	200	200	200	200	200	200	600	600

Supporting information

The commentary below is similar to previous reports as the diversity of providers that provide balancing services didn't change significantly through BP1 and is not expected to change much in BP2 unless otherwise stated.

Frequency Response

Frequency services are delivered by providers who have a Mandatory Services Agreement (MSA) agreement or who are awarded contracts through a competitive tendering process (which includes the daily auctions). Mandatory Frequency Response is primarily provided by providers with MSA registered transmission connected Units. For frequency response procured through competitive tendering the unit base is a mix of BM and Non-BM, primarily distribution connected, however we are starting to also see transmission connected storage assets that are providing frequency services. There is a continued growth in MWs from batteries providing tendered frequency services, with this asset type now making up the vast majority of the MWs provided by frequency services.

Reserve

Procurement volumes and technology mix in Q2 remain consistent with historical STOR data.

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 BM. The launch of the Voltage Pathfinders has proven that distribution network providers can also be effective to meet a transmission need. The addition of the Peak Gen shunt reactor service that went live in Q1 2022-23 has further diversified the type of providers. In January 2022 we also awarded contracts to meet reactive needs from an offshore windfarm in the Pennines region due to commence in 2024-25.

Constraints

Constraint costs occur 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 and by requiring providers to change their MW generation levels. The Constraint Management Pathfinder reduces the actions required by the ENCC to manage the constraint across the B6 boundary.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

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

The BSUoS charge (£/MWh) is now based upon a fixed tariff that was published in January 2023. Daily balancing costs (and other costs that ultimately make up the costs recovered through the BSUoS charge) were forecast for the year ahead, and two 6-month tariffs were set to cover the 2023/24 charging year.

We continue to forecast balancing costs monthly and measure our performance against this forecast as it remains an important metric to support the fixed tariff methodology, by being the main component of the fixed BSUoS tariff. The BSUoS cost forecast (costs rather than what is charged against the fixed tariff) is probabilistic and therefore produces percentile values. The published forecast for each month is based on the central value of the BSUoS cost forecast (50th percentile). If the outturn BSUoS costs are below the 50th percentile of the cost forecast, then the actual costs for that month would be lower than the forecast predicted, provided the actual volume is at or above the estimate (and vice versa).

September 2023-24 performance

Figure 16: 2023-24 Monthly BSUoS forecasting performance (Absolute Percentage Error)

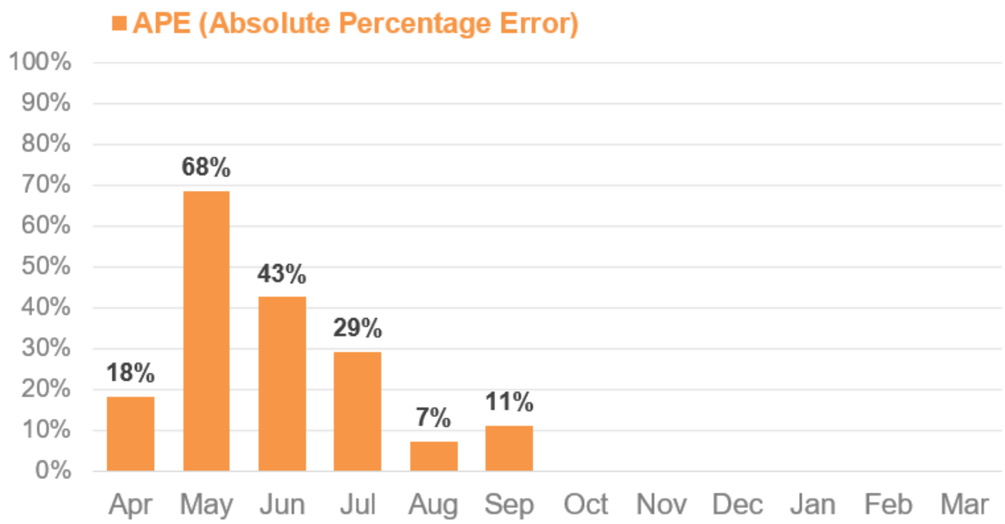


Table 19: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[5] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual (£ / MWh)	10.8	8.2	7.5	13.7	10.4	12.8						
Month-ahead forecast (£ / MWh)	12.7	13.8	10.8	9.7	9.7	11.4						
APE (Absolute Percentage Error)[6]	**18.0**	**68.4**	**42.5**	**29.1**	**7.2**	**11.0**						

[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.

Supporting information

September Performance:

Actuals out-turned above forecast in September 2023, with an increase in the Absolute Percentage Error from 7% in August to 11% in September. The main drivers were constraint costs and wholesale electricity price being higher than forecast.

Costs:

September outturn costs were around the 65th percentile of the forecast produced at the beginning of August.

The average wholesale electricity price increased by 8% between the August forecast for September (£76/MWh) and September outturn (£82/MWh). Constraint costs also increased by 34% (£109m in August forecast and £147m for September outturn.

Volumes:

September actual volume was slightly below August forecast.

Forecast for September made at the start of August: 21.0TWh

Outturn volume for September: 20.3TWh

Notable events during September 2023

Demand Flexibility Service to return this winter

On 1 September, we announced our intention to reintroduce the Demand Flexibility Service (DFS) and have submitted our proposal for this years' service to Ofgem for their approval. Alongside the formal submission to Ofgem, we have also confirmed details of the commercial proposition for the electricity suppliers, aggregators and businesses who directly contract with us.

DFS incentivises consumers, as well as industrial and commercial users, to voluntarily flex the time they use their electricity to help manage the system this winter.

Last winter, DFS successfully saved over 3,300MWh across 22 events, enough to power nearly 10 million homes. This year, we're committed to developing DFS even further and are keen for more consumers and businesses, large and small, to take advantage of this opportunity to reduce their energy bills and carbon footprint.

Alongside potential live uses of the service to balance the network this winter, we're running 12 incentivised test events that consumers and business can participate in. Electricity suppliers, aggregators and businesses who directly contract us will receive a guaranteed acceptance price of £3/kWh for least six of the test events, subject to registered volumes from January 2024.

10 year TNUoS project

Following requests from industry, we published a long-term projection of Transmission Network Use of System (TNUoS) Tariffs for 2029/30 – 2033/34.

This was provided on a one-off basis, considering tariff impacts from significant network reinforcement works including High Voltage Direct Current (HVDC) and undersea cables.

We engaged with Ofgem, DESNZ, Network Transmission Owners and the wider industry whilst working through the assumptions and inputs that we would use to create the projection.

Together, with the 5 year forecast of TNUoS tariffs that we published in April this will provide industry with a 10 year view of TNUoS tariffs from 2024/25 to 2033/34.

We hosted an industry webinar on the 25 September to help the industry better understand the publication. We had over 100 attendees for the webinar and answered approx. 40 questions during it.

Net Transfer Capacity (NTC) C28 derogation decision letter and NTC Commercial Compensation Methodology renewed and approved

Our control room (along with other European TSOs) uses NTCs when needed to restrict import or export capacity of interconnectors to maintain security of supply. As we cannot procure NTCs using market-based procedures, we are required to apply to Ofgem for a derogation against Condition C28.4(h)(i) of our transmission licence. Our most recent derogation was for a six-month period and was due to expire on 30 September 2023. In August 2023 we submitted a request to Ofgem to extend this derogation. This was following a programme of work to address comments in Ofgem's previous C28 decision letter. The programme of work included running a consultation on the NTC Commercial Compensation, data analysis on the historic use of NTCs, internal development on ways to minimise the use of NTCs and stakeholder engagement events and workshops.

In their decision letter published on 28 September 2023, Ofgem granted the ESO a derogation against C28 for NTCs until 30 September 2026. They also approved our revised NTC Commercial Consultation Methodology, which applies from 1 October 2023. This gives our control room certainty that they can use this vital tool when required for system security over the coming years.

We will continue to monitor the use of NTCs, and ways to minimise them and improve transparency, via an internal governance forum. This will include monitoring progress against a number of items Ofgem identified in their decision letter for further work.

Transmission Charging Methodology Forum (TCMF) Feedback and Improvements

TCMF is held on a monthly basis and is established under the Connection and Use of System Code (CUSC). It is attended by many parties from across the industry and is designed to provide a regular forum for discussion on the development of charging methodologies. Following the July TCMF a survey was sent out to gain feedback from attendees to understand what works well and also how TCMF can be improved to ensure it continues to be a useful forum for all. 7 responses were received and these were detailed with commentary. The response rate was lower than hoped and this was fed back to TCMF participants and will be addressed in future surveys encouraging more participation.

There was an average score of 8 on a scale of 1-10 (10 being extremely positive) when asked how useful and informative TCMF is. Other questions included what TCMF should continue/stop/start doing as well as suggested amendments and general comments. One area called out in the commentary was regarding TCMF sub-groups which was initiated for the first time in March 2023 on a topic brought up in the main meeting. These sub-groups are seen as hugely valuable alongside the main TCMF to delve into more detail on complex issues.

The survey feedback was presented in September TCMF and as part of this key areas were addressed and suggestions made to tackle these areas. Changes include introducing breaks in the meeting, calendar invites adjusted to reflect the agenda and a plan to introduce in person meetings on a quarterly basis in 2024. Terms of reference have also been updated and shared ahead of October TCMF. The feedback was constructive and there are opportunities to improve but overall comments were positive, proving TCMF continues to be a hugely effective forum.

Contracts for Difference Allocation Round 5 Concluded

Contracts for difference scheme (CfD) is the government's main mechanism for supporting new low-carbon electricity generation projects in Great Britain. The ESO, as the EMR Delivery Body is responsible for the prequalification, disputes and auction processes of the CfD scheme.

On 8th September, we published the CfD Allocation Round 5 (AR5) results. A total of 95 projects have been successful representing ~3.7GW at a cost of ~£228m (in 2012 prices) ~£294m (current price). Geothermal projects (3 projects) were awarded CfD contracts for the first time, record numbers of tidal stream projects (11 projects), and significant quantities of new solar and onshore wind generation.

As EMR Delivery Body, we are proud that the prequalification, dispute and auction processes went smoothly. A record low disputes were raised to Ofgem and Ofgem upheld our decision. This is a result of enhanced customer services and effective partnership with DESNZ and Ofgem. We are now working closely with DESNZ to implement any learnings from this first annual round to the next auction which is due in March 2024.

Role 3
(System insight, planning and network development)

ESO

RRE 3A Future Savings from Operability Solutions

April 2023 to September 2023 Performance

This Regularly Reported Evidence (RRE) outlines the forecast medium to long term benefits from new operability measures including:

i. Saved balancing costs
ii. Monetised carbon reductions
iii. Any indicative impact on the SZCP limit

In each report we show projects concluded in the BP2 period so far, with estimated benefits for up to the end of contracts. In the narrative we also call out what upcoming projects are likely to be included in subsequent reports during BP2

i. Saved balancing costs

Table: Forecast balancing costs savings for operability measures concluding in BP2 so far

Operability Solution projects	Forecast Savings (£m)
Constraints Management Pathfinder (CMP) B6 extension (October 2025 to September 2026)	**45***
TOTAL	**45***

* The method to calculate the costs savings it to compare the forecast constraint costs had the B6 contracts not been extended against those with the service being extended. The model we use forecasts constraints across the whole of GB, rather than specifically on the B6 boundary. In future reports we will aim to provide a detailed breakdown of constraint costs on the B6 boundary.

In future BP2 incentive reports, we will include the forecast savings of further operability measures as they are completed.

These future projects may include:

- Implementation of the FRCR policy on minimum inertia requirements
- The first Stability Y-1 tender which is expected to conclude in September 2024 for service delivery between October 2025 and September 2026.
- Voltage 2026 tender which is expected to conclude in September 2024
- EC5 Interim tender that will conclude in Q3 23-24
- EC5 Enduring tender that will conclude in Q2 24-25

The expected completion dates for the above projects are subject to change and further updates will be provided in future BP2 reports.

Supporting information

Constraints Management Pathfinder (CMP) B6 – Extension of contracts to September 2026

The CMP service has completed two rounds of tenders, awarding annual contracts for delivery between October 2023 to September 2025. However, as some of the contracted units were already connected to the intertripping scheme, we requested that these units commence their service from April 2022, bringing forward the cost and carbon savings as reported in the BP1 End of year report.

We intended to revise how the CMP service is procured, from annual tenders with year-long contracts to a one-off tender with longer term agreements. To allow ourselves time to update the commercial, contractual and technical aspects of the service, we enacted the one-year extension option from the B6 year 2 contracts in Q2 23-24 which ensures that the current service will be in place until September 2026. This will continue to deliver cost and carbon savings as reported in section compared to alternative options for managing constraints.

ii. Monetised carbon reductions

The carbon prices used in the tables below are taken from the BEIS publication ‘valuing greenhouse gas emission in policy appraisal’ [7]. These prices are also those used in our RIIO-2 Business Plan 2 Cost-Benefit Analysis – Annex 2 [8].

Constraints Management Pathfinder (CMP) B6 extension

Constraint Management Pathfinder B6	Unit	2025-26	TOTAL
CCGT generation output avoided in GWh	GWh	322	322
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	n/a
CO2 in tonnes	tCO2	126,868	126,868
Carbon price (BP2)	£/tCO2e	260	260
Savings	**£m**	**33.0**	**33.0**

Supporting information

B6 Constraint Management Pathfinder

The Constraint Management Pathfinder B6 contracts are a contractual arrangement where generators in Scotland are contracted to provide an intertrip service to alleviate system constraints. This allows more renewable generation to be exported which would otherwise have been curtailed. The service has been in use since April 2022 with the table above showing forecast savings for the contract delivery period of October 2025 to September 2026. To calculate the monetised value of carbon savings, we have used the BEIS valuing greenhouse gas emission in policy appraisal prices for 2025/26.

The constraint service is estimated to deliver savings of:

- Avoided generation from CCGTs: 322GWh
- Avoided CO2: 127k Tonnes
- **£ Savings: £33m**

[7] https://www.gov.uk/government/publications/valuing-greenhouse-gas-emissions-in-policy-appraisal
[8] https://www.nationalgrideso.com/document/266121/download

iii. Any indicative impact on the SZCP limit

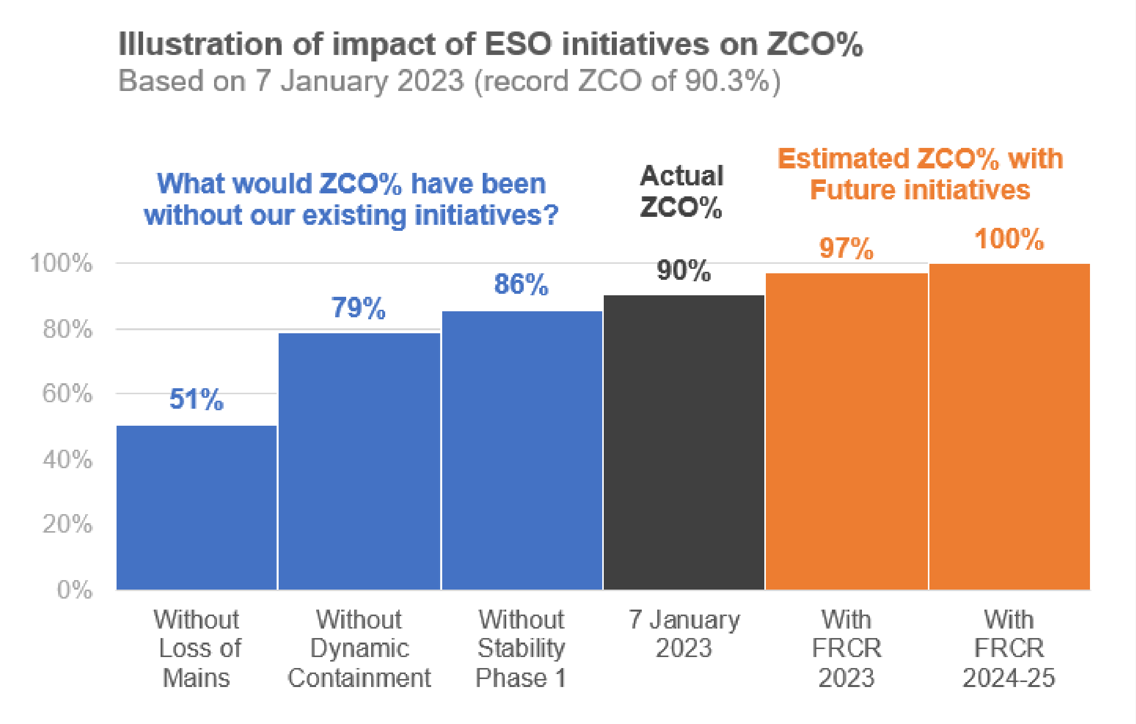
The current record for Zero Carbon Operation was 90.3% on 7 January 2023 between 19:30-20:00 and Carbon Intensity was 43g CO2/kWh. There were eight carbon emitting generators on the system at the time.

The below graph shows how much lower the ZCO% would have been on 7 January without the delivery of Stability Phase 1, Dynamic Containment and the Loss of Mains change programme. Each programme is assessed independently rather than cumulatively.

- **Stability Phase 1** delivered 12.5GVA.s of inertia, reducing the need for four units at 1000MW. Without Phase 1 the ZCO% would have been 86%.
- **Dynamic Containment (DC)** has significantly reduced the need to hold legacy frequency response products. Without DC, an additional 2,500MW of headroom would have been required on synchronous carbon emitting generation. This equates to 10 units at 250MW each, reducing the ZCO% to 79%.
- **The Loss of Mains change programme** has reduced the potential volume of embedded generation susceptible to trip following a frequency change faster than 0.125Hz/s. Had we not completed the programme, we would have required 253GVA.s of inertia to prevent the largest single generation loss causing frequency to change faster than 0.125Hz/s, leading to further generation loss. The system was expected to have 148GVA.s, so an additional 35 units would have been needed to deliver 105GVA.s at 250MW each. This would have reduced the ZCO% to 51%.

The graph then shows how our future projects will help close the ZCO gap to 100% by 2025.

- **FRCR 2023** has reduced the minimum inertia requirement by 20GVA.s to 120GVA.s, which has the effect of needing approximately six less carbon emitting generators. This would increase the Zero Carbon MW by 1500MW and the ZCO% to 97%.
- **FRCR 2024 to 2025** will analyse the potential to reduce the minimum inertia requirement by a further 18GVA.s to 102GVA.s. This would effectively increase the Zero Carbon MW by another 1500MW and the ZCO% to 102%.



NB - The calculations make assumptions about the contribution to system needs on 7 January 2023, taken from FRCR. Each synchronous generator provides 3GVA.s of inertia, operating at a minimum output (Stable Export Limit – SEL) of 250MW with a maximum available output of 500MW.

Whilst this exercise shows that future projects will enable a day like 7 January to be zero carbon, there are further projects which will enable zero carbon on other days too.

There are four reactors being delivered by April 2025 which are for economic reasons, effectively removing the need for a further four generators (1000MW).

Stability Phase 3 bought 17.1GVA.s which, once delivered, removes the need for five units (1250MW).

Looking beyond 2025, our voltage tender for 2026 will procure enough reactive power to remove another two units (500MW).

RRE 3X Timeliness of Connection Offers

This Regularly Reported Evidence (RRE) reports on the number of connection offers made within 3 months of clock start date, and the number of connection offers made that took longer than 3 months.

We provide this information separately for the England and Wales area, the Scotland area and by Transmission Owner (TO) area:

- England and Wales: National Grid Electricity Transmission (NGET)
- Central and Southern Scotland: SP Transmission (SPT)
- North of Scotland: Scottish & Southern Electricity Networks (SHET)

In year 1 (2023-24), in England and Wales, while the two-step offer process is running we will report:

- The number of standard offers issued within 3 months.
- For two-step offers, the number of (one-step) offers issued within 3 months.
- the number of two-step offers issued within nine months, after counter signature of the step one offer;
- and the number of any connection offers that took longer than the above timeframes.

We also report on the scale of the connection queue in terms of GW and time from offer acceptance to connection date. We include a breakdown of assets in the connection queue by size, technology type, and TO area.

Please note these figures are consistent with the Connections monthly data submission provided to Ofgem.

Table 20: Quarterly connection offers by time taken

Area	Connection offers issued:	Q1	Q2	Q3	Q4	Total
NGET (England and Wales)	(Standard offer) Within 3 months	162	28			
	(One-step) Within 3 months	23	154			
	(Two-step) Within 9 months*	0	0			
	Longer than the above timeframes	0	0			
	Total	**185**	**182**			
SPT (Scotland)	(Standard offer) Within 3 months	77	104			
	Longer than 3 months	0	4			
	Total	**77**	**104**			
SHET (Scotland)	(Standard offer) Within 3 months	95	89			
	Longer than 3 months	0	2			
	Total	**95**	**89**			
TOTAL	Within 3 months	**357**	**369**			
	Longer than 3 months	**0**	**6**			
	Total	**357**	**375**			

* after counter signature of the step one offer

Figure 17: Connections queue in MW split by time from offer acceptance to connection: Q1 (30 June 2023) vs Q2 (30 Sep 2023)

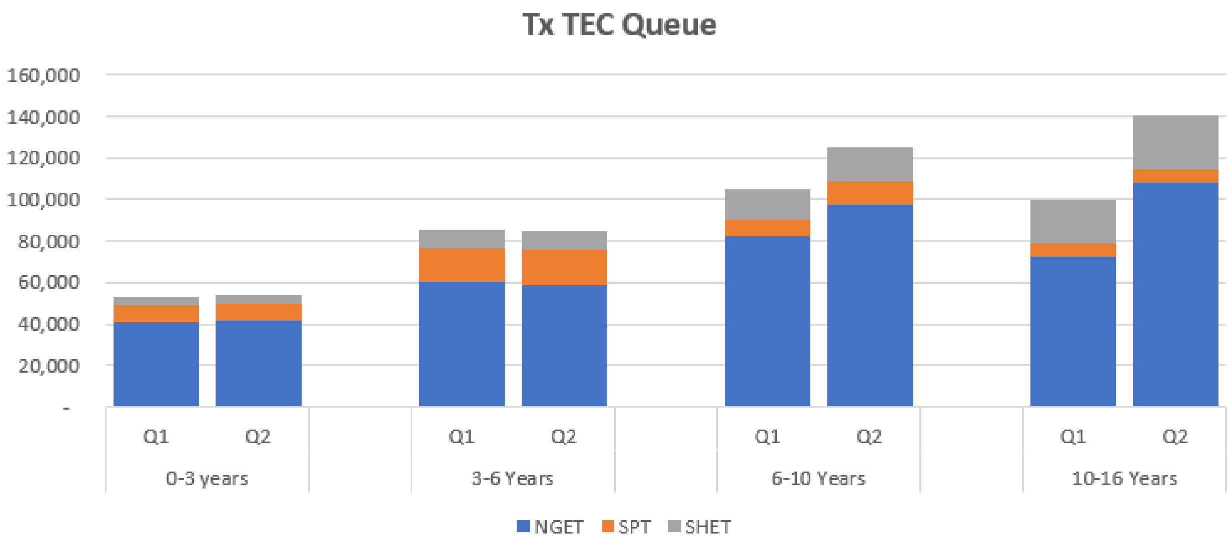
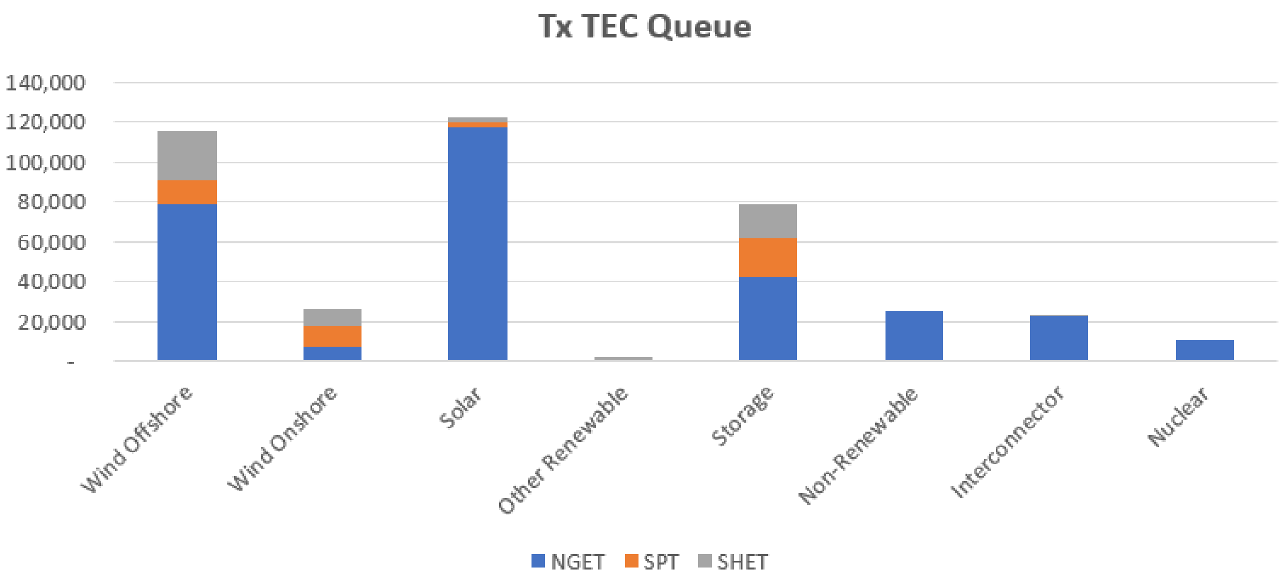


Table 21: Connections queue in MW split by time from offer acceptance to connection

Host TO	Unit	0-3 years	3-6 Years	6-10 Years	10-16 Years	Total
NGET	MW	41,283	58,345	97,636	107,594	**304,858**
SPT	MW	8,484	17,609	11,444	6,945	**44,482**
SHET	MW	4,330	8,736	16,168	25,492	**54,727**
Total	MW	**54,097**	**84,691**	**125,247**	**140,031**	**404,067**

Figure 18: Connections queue in MW by technology type (30 Sep 2023)



Note: Since the Q1 report, the fuel type classifications have changed in line with other regulatory reporting. Therefore we are unable to show the change at technology level compared to Q1. From Q3 onwards we will be able to show change compared to the previous quarter.

Figure 19: Connections queue in MW by technology type (30 Sep 2023)

Host TO	NGET	SPT	SHET	Total
Wind Offshore	97,122	11,356	24,768	**115,246**
Wind Onshore	7,727	10,355	8,282	**26,343**
Solar	117,021	2,802	2,696	**122,518**
Other Renewables	733	-	287	**1,020**
Storage	42,037	19,990	17,294	**79,321**
Non-Renewable	24,985	-	-	**24,985**
Interconnector	22,554	-	1,400	**23,954**
Nuclear	10,680	-	-	**10,680**
TOTAL	**304,858**	**44,482**	**54,727**	**404,067**

Supporting information

Timeliness of connection offers

Application volumes continue to increase in comparison with 2022/23 and this is reflected in the number of offers being sent out across all 3 TOs.

The 6 offers sent outside of CUSC timescales were the offers alluded to in the Q1 report where a request was sent to Ofgem to approve an extension. These offers have now been sent. No further extensions have been requested during Q2.

Connections queue

The Connections queue continues to increase moving from 343GW at the start of Q2 to 404GW at the end of the quarter. The vast majority of this increase is due to new connection applications from battery storage developers. A large increase in connection dates for the 6-10 year and 10-16 year periods can be seen, which is in line with average connection timescales of 10 years in E&W and 7 years in Scotland.

RRE 3Y Percentage of 'right first time' connection offers

This RRE measures the % of connection offers made which did not need reissuing. For those that needed reissuing, we break these down by reason.

We include details of the number of connection offers made for the England and Wales area, and the Scotland area, in addition to by TO area. During the period where the 2-step offer process is in place, we will report this separately for step 1 and step 2 offers.

Table 22: Quarterly % of 'right first time' connection offers

Area	Connection offers	Q1	Q2	Q3	Q4	Total
NGET	Total Step 1 offers signed	1	72			
	Number right first time	1	70			
	Percentage right first time	**100%**	**99%**			
	Total Full / Step 2 offers signed	222	147			
	Number right first time	182	121			
	Percentage right first time	**95%**	**93%**			
SPT	Total connection offers signed	50	48			
	Number right first time	38	42			
	Percentage right first time	**88%**	**98%**			
SHET	Total connection offers signed	46	63			
	Number right first time	36	48			
	Percentage right first time	**91%**	**95%**			
TOTAL	Total connection offers signed	319	330			
	Number right first time	257	281			
	Percentage right first time	**93%**	**95%**			

Table 23: Connection offer that needed reissuing by reason

Area	**One-step** connection offers	Q1	Q2	Q3	Q4	Total
NGET	Customer driven	18	14			
	ESO driven	12	11			
	TO driven	24	13			
	Total	**40***	**28***			
SPT	Customer driven	6	5			
	ESO driven	6	1			
	TO driven	3	4			
	Total	**12***	**6***			
SHET	Customer driven	4	7			
	ESO driven	4	3			
	TO driven	4	7			
	Total	**10***	**15***			
TOTAL	Customer driven	28	26			
	ESO driven	22	15			
	TO driven	31	24			
	Total	**62***	**49***			

* Please note that re-offers can be driven by more than one factor. Therefore the totals can be lower than the sum of the figures for each reason

Supporting information

Numbers of re-offers are spread across the TOs relative to the number of offers signed within the period, and the drivers for the re-offers are fairly evenly distributed with ESO driven re-offers coming in a little lower than the others.

There are a variety of reasons leading to an offer being re-issued such as amendments to appendices, charging statements and offer documents following post-offer discussions.

The number of ESO Driven re-offers directly affects our performance percentage, which is calculated by looking at the number of offers Right First Time not due to an ESO re-offer. Re-issued offers and the reasons for them are continuously reviewed.

Notable events during September 2023

Connections Portal Stakeholder workshop for all Customers

On 28 September, the GB Connections Process & Solutions team held a stakeholder workshop for all customers of the Connections Portal. Through this workshop we presented customers with the development journey of the portal so far, demonstrating features that we have added since its inception in March, as well as highlighting future improvements to the platform we intend to make. We were also able to emphasize the positive impact the portal has had on application submissions to clock-start timescales, with a 20% decrease in Q1 this year in comparison to Q1 last year. We were joined by circa 100 customers in the session and had really positive engagement with them throughout, as it provided an opportunity for customers to feedback to us how they are finding use of the portal, features that they find useful and suggest future changes they may like to see. The feedback that we captured has since been scored and prioritised on the project backlog, with some of the suggestions being earmarked for development and deployment to the portal in the near future. Customer engagement plays a key part to the success of the Connections Portal and this session was part of a series of sessions we have held and will continue to do so going forward.

How will the Virtual Energy System be built? webinar on 21 September

ESO's Virtual Energy System (VirtualES) is a social-technical programme and a shared asset that is being built and operated by members of the Great Britain's energy industry. Our ambition is to build a digital representation of GB's whole energy system through digital twin technology, and we want to work with all energy players and technology providers to build the Virtual Energy System collaboratively.

ESO and Arup, supported by Energy Systems Catapult and Icebreaker One, have been developing a social-technical common framework to enable the creation of an ecosystem of connected digital twins of an entire energy system. This framework has 14 key factors that lay the groundwork for best practices to help us all connect assets, systems, and digital twins across Great Britain. Six of these factors have been prioritised for development first - you can read about these here:

- Technical factors (aligning models and taxonomies, increasing visibility and enabling sharing, creating an interoperable tech stack)
- Creating a governance framework
- Raising awareness and fostering culture
- Engaging stakeholders

As part of the programme's engagement campaign to launch the guidance notes on priority factors of how to build the VirtualES, we hosted the 'How will the Virtual Energy System be built?' webinar on the 21 September 2023.

The webinar was successfully delivered, with over 100 attendees (including ESO, National Gas, DNOs, UKPN, Energy Security, Government and regulators) joining to learn about ESO's Virtual Energy System, unpack the 6 priority factors in detail and hear about our next steps.

The slides presented during the webinar have been published on the ENA's Smarter Networks Projects website, under the 'Documents' section.

Future Energy Scenarios 2024 Framework Workshop

On 28 September 2023 we hosted a workshop with stakeholders to gather views on the draft framework for the next publication of our Future Energy Scenarios (FES). Changes to the strategic transmission network planning process are driving new requirements of FES and the workshop was a great opportunity to update stakeholders and listen to the views on the draft proposals. We were joined by over 30 stakeholders representing a range of organisations from academics, regulators, generators, think-tanks and research consultancy. We will be considering the feedback received from our engagement the framework and analysis and will continue with the development of our plans and stakeholder engagement over the coming weeks and share more later on in the year.

Connections Issues Steering Group (CISG) – subgroup raised

In July, we held our first CISG sub-group on Connections strategic change and impact to the Connections and Use of System Code (CUSC). Representatives from the CUSC panel suggested that there would be value in having additional and specific CUSC commercial sessions to understand the ESOs proposed changes to the connection process and new policy, with the focus primarily on discussing Connections five-point plan.

The scope of the subgroup is to :

- provide clarity on the horizon of strategic connection change;
- signposting to more medium term-change, such as Connections Reform;
- Focusing immediate discussions on connections five-point plan initiatives, including the ESO's new policy for battery storage connections
- Breaking down the ESO's line of thinking with regards to implementation of these initiatives
- Providing opportunity to deep dive on those change initiatives of interests.

Held monthly and on-line, we have had 4 meetings to date. On 26 September we held our 3rd subgroup meeting, where an update on topics such as five point plan and connections reform were given. More information on this session can be found here. If you're an existing or prospective user of the CUSC, or a representative from an industry body, you are welcome to attend the sub-group meeting.

Plan Delivery, Stakeholder Evidence & Value for Money

All roles

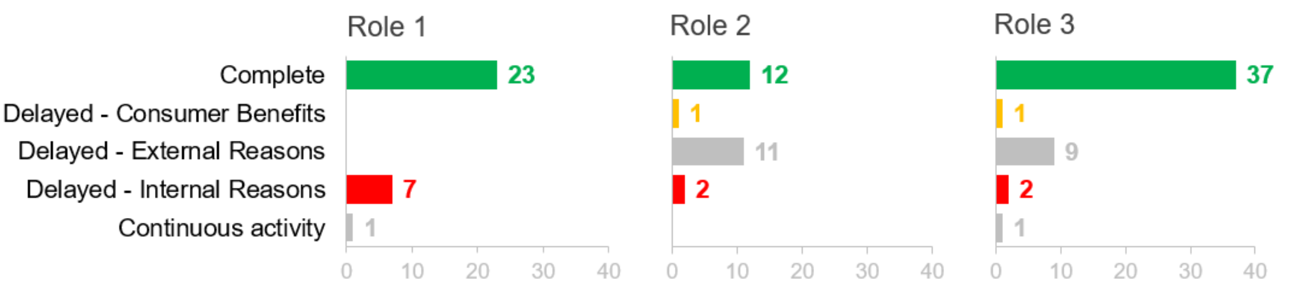
Plan delivery

Our BP2 RIIO-2 deliverables tracker (open in Chrome) which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

The statuses are defined as follows:

On track	For a milestone date in the future: we're on track deliver it on time
Complete	Milestone has been delivered
Delayed – consumer benefits	Delayed or de-prioritised to maximise consumer benefits
Delayed – external reasons	Delayed due to factors outside our control (e.g., BREXIT, Covid, Ofgem)
Delayed – internal reasons	Delayed due to factors within our control and/or that we're accountable for
Continuous activity	This is a fixed status for certain activities with ongoing delivery (e.g., OTF)

Status of all milestones with target completion dates in H1 2023-24



Note a status of 'on track' is not shown as this can only apply to milestones due to complete in future months .

Role 1 - Progress of our deliverables

For Role 1 (Control Centre Operations), the Delivery Schedule lists **52 deliverables** in total, which is made up of **142 milestones**.

- **31** of these milestones were due to be completed by September 2023
- Of those:
    - **0** are delayed in order to deliver an improved outcome for consumers
    - **0** are delayed due to reasons outside the ESO's control
    - **1** is a continuous activity (the status doesn't change)
- Of the remaining 30**:**
    - **23** (77%) are now complete
    - **7** (23%) are delayed due to ESO related delays

The results for the 31 milestones due to be completed by September 2023 are illustrated below:

Role 1 – Milestone status by deliverable
For milestones due in Q1 and Q2 2023-24

Ref	Deliverable name (shortened)	Continuous activity	Complete	Delayed... Consumer Benefits	Delayed... External reasons	Delayed... Internal reasons
D1.1.7	Produce and publish detailed forecasts and analysi...	-	-	-	-	1
★ D1.2.1	(Now known as 'Future of Balancing') Enhanced bala...	-	1	-	-	1
★ D1.2.2	Develop inertia monitoring capabilities and other ...	-	-	-	-	1
D1.3.1	Develop and deliver new real-time situational awar...	-	-	-	-	1
D1.3.3	Upgraded Control Centre video walls and operator c...	-	2	-	-	-
D1.4.2	Continue to facilitate meetings of the Technology ...	-	2	-	-	-
D1.5.1	Increased DER visibility in real-time operations	-	2	-	-	-
D1.5.2	Whole electricity system operational service coord...	1	1	-	-	-
D1.5.4	Increased operational liaison	-	2	-	-	-
D1.6.2	An agile programme of strategic and tactical Balan...	-	1	-	-	-
D1.6.3	Stakeholder Engagement on Minimising Balancing Cos...	-	1	-	-	-
D17.3	Transparency Roadmap	-	1	-	-	-
D2.2.1	Development of new modules and (based on feedback)...	-	1	-	-	1
D2.2.2	Enhanced training and simulation with DNOs and wid...	-	1	-	-	-
D2.3.1	Upgrades to current simulators, including annual s...	-	-	-	-	1
D2.3.2	New training methods and platforms, including onli...	-	2	-	-	-
D2.4.1	Personalised updates and automated shift logins to...	-	1	-	-	-
D2.4.2	Content and infrastructure for personalised traini...	-	2	-	-	-
D3.1.3	Engage and collaborate with industry to plan and d...	-	1	-	-	-
D3.2.1	Facilitate and compile, on behalf of the GB indust...	-	1	-	-	-
D3.2.3	Maintain obligations and requirements against the ...	-	-	-	-	1
D3.3.2	Subject to industry adoption, Distributed ReStart ...	-	1	-	-	-
	TOTAL - Role 1	**1**	**23**	**-**	**-**	**7**

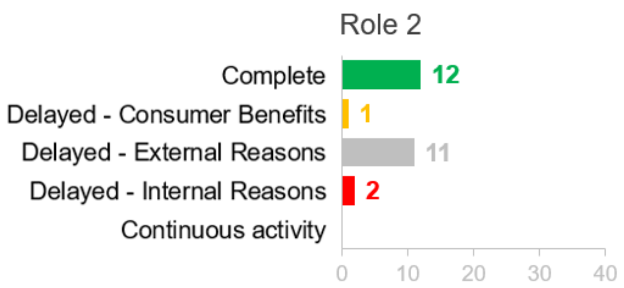
★ **D1.2.1 and D1.2.2** - Milestone delivery dates in the BP2 Delivery Schedule are incorrectly misaligned with DD&T Annex 4 roadmap. Milestone delivery is on track against the DD&T Annex 4 roadmap.

Role 2 - Progress of our deliverables

For Role 2 (Market development and transactions), the Delivery Schedule lists **47 deliverables** in total, which is made up of **133 milestones**.

- **26** of these milestones were due to be completed by September 2023
- Of those:
  - **1** is delayed in order to deliver an improved outcome for consumers
  - **11** are delayed due to reasons outside the ESO's control
  - **0** are continuous activity (the status doesn't change)
- Of the remaining 14:
  - **12** (86%) are now complete
  - **2** (14%) are delayed due to ESO related delays

The results for the 26 milestones due to be completed by September 2023 are illustrated below:



Role 2 – Milestone status by deliverable
For milestones due in Q1 and Q2 2023-24

				Delayed...		
Ref	Deliverable name (shortened)	Continuous activity	Complete	Consumer Benefits	External reasons	Internal reasons
D15.8.3	Enabling whole electricity system operational serv...	-	-	-	2	-
D21.1	Cross-border strategy development	-	1	-	-	-
D21.1.1	Strategic Engagement with EU	-	-	-	1	-
D21.2.1	Continued facilitation of EU driven code changes i...	-	-	-	1	1
D21.2.2	Implementation of the TCA	-	-	-	1	-
D4.2.1	Regular and specific metrics and publications acro...	-	1	-	-	-
D4.3.6	Future developments to frequency response services	-	1	-	-	-
D4.4.1	A market platform through which market participant...	-	1	-	-	-
D4.4.2	Common standards, including interoperable systems,...	-	-	1	-	-
D4.5.5	Ensure co-ordination of markets across the whole e...	-	-	-	1	-
D5.1.1	Continuation of Electricity Market Reform (EMR) De...	-	2	-	-	-
D5.1.2	Continuation of EMR Delivery Body obligations:We ...	-	1	-	-	-
★ D5.2	Developing the EMR platform	-	-	-	-	1
D5.3	Use of enhanced modelling and more granular data s...	-	1	-	-	-
D5.4	Building our long-term security of supply modellin...	-	1	-	-	-
D6.1.3	Enable zero carbon operation - System Restoration	-	-	-	2	-
D6.1.4	Enable zero carbon operation - Stability	-	1	-	-	-
D6.1.6	Support Market Wide Half Hourly Settlement	-	-	-	1	-
D6.3	Continued managing, collecting and disbursing char...	-	1	-	-	-
D6.3.1	Market half-hourly settlement	-	1	-	-	-
D6.3.2	TNUoS reform	-	-	-	2	-
	TOTAL - Role 2	**-**	**12**	**1**	**11**	**2**

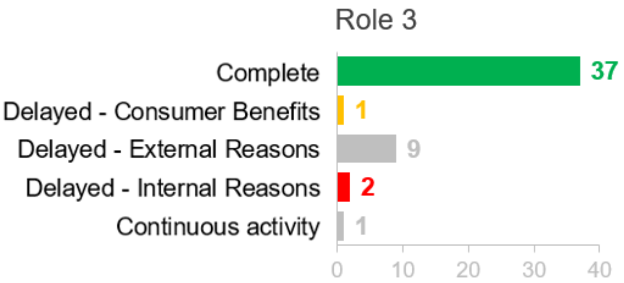
★ **Developing the EMR platform**: Milestones and associated delivery dates will be updated to align to latest delivery plan. We will update the deliverables tracker for the next quarterly update. Milestones currently on track against latest delivery plan.

Role 3 - Progress of our deliverables

For Role 3 (System insight, planning and network development), the Delivery Schedule lists 63 deliverables in total, which is made up of 218 milestones.

- **50** of these milestones were due to be completed by September 2023
- Of those:
  - **1** is delayed in order to deliver an improved outcome for consumers
  - **9** are delayed due to reasons outside the ESO's control
  - **1** is a continuous activity (the status doesn't change)
- Of the remaining **39**:
  - **37** (95%) are now complete
  - **2** (5%) are delayed due to ESO related delays

The results for the 50 milestones due to be completed by September 2023 are illustrated below:



Role 3 – Milestone status by deliverable
For milestones due in Q1 and Q2 2023-24

Ref	Deliverable name (shortened)	Continuous activity	Complete	Delayed... Consumer Benefits	External reasons	Internal reasons
D12.2	Potential solutions identified and direction estab...	-	1	-	-	-
D13.1	Published Future Energy Scenarios (FES), Winter Ou...	-	2	-	-	-
D13.2.1	Provide whole system regional insights	-	2	-	-	-
D13.3	Shared insights on future energy expectations and ...	-	2	-	-	-
D14.3.1	Establish dedicated Distributed Energy Resource (D...	-	-	-	-	1
D14.3.3	Whole electricity system connection seminars on an...	-	2	-	-	-
D14.3.4	Improving Systems and Data	-	2	-	-	-
D14.4.1	Implement first phase of the ESO connections porta...	-	2	-	-	-
D14.4.2	Phase 2 of the connections portal concluded	-	2	-	-	-
★ D14.5.1	Connections Reform Phase 1	-	1	-	1	-
★ D14.5.2	Connections Reform Phase 2	-	2	-	-	-
D15.1.1	System Operability Framework (SOF) documentation t...	-	2	-	-	-
D15.11.2	Forward Plan 2020-21 RDP - Generation Export Manag...	-	-	-	1	-
D15.4.2	Technical modelling for use across the ESO – ongoi...	1	1	-	-	-
D15.5.2	RDP2 of RIIO-2 (MW dispatch, South East, UKPN)	-	-	-	1	-
D15.5.3	RDP3 of RIIO-2 (wider rollout & enhancements, WPD)	-	-	-	2	-
D15.5.4	RDP4 of RIIO-2 (wider roll out & enhancements UKPN...	-	-	-	2	-
D15.5.5	Deliver GB rollout of functionality developed thro...	-	1	-	-	-
D15.5.6	RDP5 of RIIO-2	-	1	-	-	-
D15.5.7	RDP6 of RIIO-2	-	1	-	-	-
D15.6.8	Development & ongoing maintenance of EMT Capabilit...	-	2	-	-	-
D15.6.9	Co-simulation analysis innovation project	-	1	-	-	-
D15.8.2	Enabling whole electricity flexibility service pro...	-	1	1	-	-
D16.2.1	Great Britain (GB) wide NAP process goes live incl...	-	2	-	-	-
D16.5.1	Agreed future platform for any automation and crea...	-	2	-	-	-
D16.5.2	Scope future automation development	-	2	-	-	-
D7.1	Electricity Ten Year Statement (ETYS)	-	1	-	-	-
D7.2	NOA Annual Report	-	1	-	-	-
D7.3	Large Onshore Transmission Projects (LOTI) (previo...	-	1	-	-	1
D8.4	Early Competition	-	-	-	2	-
	TOTAL - Role 3	**1**	**37**	**1**	**9**	**2**

★ **Connections Reform deliverables**: Awaiting Ofgem to approve updated milestones and associated delivery dates to align to latest delivery plan. We will update the deliverables tracker for the next quarterly update. Milestones currently on track against latest delivery plan.

Stakeholder evidence

The ESO incentive scheme includes a criterion for Stakeholder Evidence, where the Performance Panel considers stakeholders' satisfaction on the quality of the ESO's plan delivery. To demonstrate performance against this criterion, every six months we report on our stakeholder satisfaction survey results.

Stakeholder surveys

The ESO has commissioned surveys from market research company BMG. These surveys measure satisfaction for each ESO role, and are carried out on a six-monthly basis. The survey is targeted at senior managers, decision makers and experts, and includes a wide selection of relevant stakeholders who have had material interactions with the ESO's services. In total we contacted **1364** stakeholders, across all 3 roles.

Role 1

For Role 1, the following question was asked:

> "One of the ESO Roles is focused on Control Centre Operations, which includes key activities such as real-time system operation, system restoration, balancing mechanism review and provision of data and forecasting. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

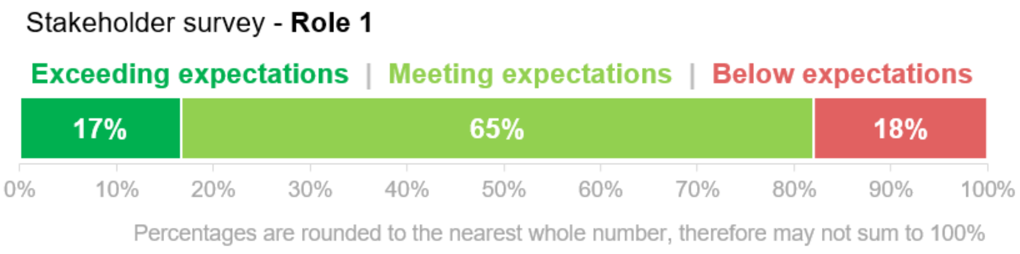
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 1, we contacted **442** stakeholders, and received **78** responses to this question, which were distributed as follows:

- **17%** exceeding expectations
- **65%** meeting expectations
- **18%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 1
"Exceeding Expectations" **13** stakeholders scored us as "Exceeding expectations". They were asked what the ESO did that exceeded their expectations.	• **Continued system resilience/stability** – many stakeholders commented on how we've safely managed the system over the past year and improved communications despite increasing challenges. We have done this by being flexible to different situations. • **Improved transparency on real time system operations through the OTF** – we have also constantly improved our data availability, been actively engaging in the market, and responding well to any criticism. • Other positive comments focused on improved structure and communication particularly during winter, coming back to trade requests well within the expected timeframe and how the control room is developing market based solutions in a quickly evolving market.
"Meeting Expectations" **51** stakeholders scored us as "meeting expectations". They were asked what it would take for the ESO to be exceeding expectations for them.	• **Better communication and planning** – including working more collaboratively to solve issues, making improvements to data transparency and quicker decision making and responses. • **Improvements to the Operational Transparency Forum (OTF)** – many stakeholders praised the OTF but had suggestions for improvements including providing answers to a broader range of questions, presenters giving more detailed insight into the information they are presenting (not just stating the obvious from what is on a chart or graph). Stakeholders also want us to be more responsive when questions around the Balancing Mechanism actions are posed. • **Reductions in balancing costs** – overall many stakeholders feel that we are performing our core role and it is difficult to achieve exceeding expectations. However, a future reduction in Balancing Costs could help us to do this. • **Deliver promised IT improvements** – stakeholders have heard a lot about planned improvements on dispatch decisions and on new systems in the control room, but many are waiting to see how these are delivered. Other improvements suggested include speed in updating controller systems, making markets more accessible to smaller units and better whole system interactions. • Other topics mentioned by smaller numbers of stakeholders include improve forecasting, utilise STOR when it's on market, better battery dispatch in the BM and more appropriate skip rate analysis.

"Below Expectations" **14** stakeholders scored us as "below expectations". They were then asked the ESO needed to do to meet their expectations.	• **Modernise our outdated systems** – this was a common theme and although stakeholders recognise that significant delays and under delivery of planned IT investment and upgrades have contributed to this, they feel improvements need to be made quicker. • **Provide greater transparency** – key data such as physical notifications are not published to the market and we need to provide clarity and certainty around real time operations. • **Be more flexible and responsive** – for example, providing an efficient dispatch service in the control room. • Other issues raised by smaller numbers of stakeholders were skip rates and the need to stop scripted answers, being more responsive to customer issues, taking proactive steps to reform dispatch transparency and making Balancing Market sign up easier and faster.

Role 2

For Role 2, the following question was asked:

> "One of the ESO Roles is focused on Market Development and Transactions, which includes key activities such as Market Design, Balancing Services, Electricity Market Reform (EMR) and Industry Codes and Charging. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

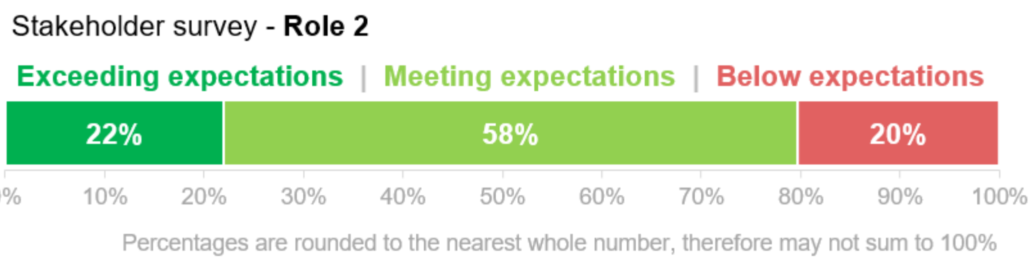
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 2, we contacted **351** stakeholders, and received **59** responses to this question, which were distributed as follows:

- **22%** exceeding expectations
- **58%** meeting expectations
- **20%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 2
“Exceeding Expectations” **13** stakeholders scored us as “Exceeding expectations”. They were asked what the ESO did that exceeded their expectations.	• **Proactivity in engaging stakeholders in difficult circumstances** – feedback included examples of excellent engagement and collaborative working. • **DFS last winter was well managed** – we’ve also listened to industry when designing the service for the second year. • **Learning from other projects** – we’ve learnt and applied our knowledge to new projects. • **Leading the world in developing new markets** – such as the Open Balancing Platform. However, some feedback highlighted that it is difficult for stakeholders to know when to expect the delivery of new services.
“Meeting Expectations” **34** stakeholders scored us as “meeting expectations”. They were asked what it would take for the ESO to be exceeding expectations for them.	• **Improve how we share information** – provide clearer meeting minutes, clearer information on industry charges and what markets stakeholders are eligible to participate in. Stakeholders would also like more information on delays to future services and more general market information such as market data analysis. • **Be more proactive** – in our market development or in engaging industry on developments of our services. • **Listen more, be more customer centric and don’t always lead the conversation** – our newsletters are helpful, but our stakeholder sessions could be more interactive. We also need to show more equitable treatment of smaller generators.
“Below Expectations” **12** stakeholders scored us as “below expectations”. They were then asked the ESO needed to do to meet their expectations.	• **Deliver faster and prioritise nearer term markets** – we are taking too long to deliver services, for example in local constraints markets and quick and slow reserve markets. • **Be more proactive in developing projects with industry feedback** – we need to share information earlier in the project development and run more interactive sessions. Projects called out specifically included Demand Flexibility Service, Local Constraint Market and the Electricity Market Reform portal. • **Being more open and less inward looking** – with more consideration of smaller players was a theme running through several comments. • **Reliability in responding to queries** – we’ve made improvements in addressing stakeholder needs but need a reliable ticket service where queries don't get lost in the system, and we deliver a human response if things aren't going well. • Several stakeholders also fed back that we have spent too much time considering locational marginal pricing in our market development work.

Role 3

For Role 3, the following question was asked:

> "One of the ESO Roles is focused on system insight, planning and network development, which includes key activities such as Connections and Network access planning, Strategy and Insight (e.g. FES) and long-term Network development. Overall, from your experience in these areas over the last 6 months, how would you rate ESO's performance?"

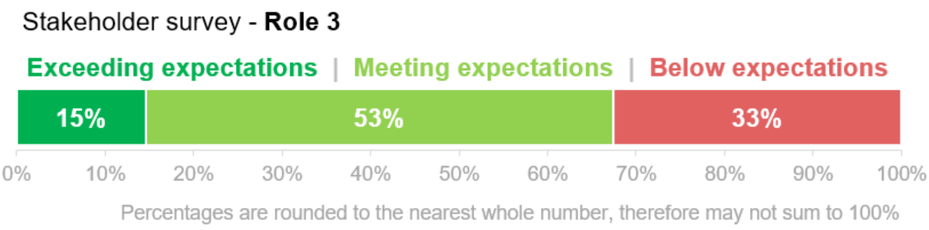
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- If they rated the ESO as below expectations, they were asked what the ESO needed to do to meet their expectations.
- If they rated the ESO as meeting expectations, they were asked what the ESO needed to do to exceed their expectations.
- If they rated the ESO as exceeding expectations, they were asked what the ESO did that exceeded their expectations.

For Role 3, we contacted **571** stakeholders, and received **144** responses to this question, which were distributed as follows:

- **15%** exceeding expectations
- **53%** meeting expectations
- **33%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 3
"Exceeding Expectations" **21** stakeholders scored us as "Exceeding expectations". They were asked what the ESO did that exceeded their expectations.	• **FES has exceeded expectations** – stakeholders like the breadth of information and analysis provided, the clear definition of the scope and that we engaged a wide group of stakeholders engaged. One comment described FES as world leading. • **Good examples of communication and engagement** – some stakeholders specifically commented on the Operating Code 2 forum, updates across connections for battery storage, frequent connections webinars and general engagement around connections. • **Good response times to queries** – we've improved our responsiveness in recent months and quickly responded to queries through OTF. • **R&D activities (offline modelling)** – to address challenges in long term network development was also called out.

"Meeting Expectations" **76** stakeholders scored us as "meeting expectations". They were asked what it would take for the ESO to be exceeding expectations for them.	• **Improve our communication and engagement** - generators requested more support through construction of their assets. Our communication also needs to be more consistent and proactive, and we need to provide more feedback to customers. Feedback on our query response time was mixed. • **Improve the connections process -** stakeholders want to see quicker connection offer times, more actions on improving the connections department and reform process and acceleration of our connection reform. • **Further development of FES** - we had positive comments around FES and the fact we are continuing to develop it. Future development ideas include a focus on real market indicators, not using a top-down approach and being more transparent with the data we use in FES. • **Constructive feedback around network development** – again we received suggestions for how we could continue to develop in this area including more anticipatory network reinforcements, and going into greater depth and providing better network planning. We had some specific TO feedback looking for us to fully assess submission of long-term outage programmes and give accurate guidance to the TOs on acceptable outage timescales and customer issues.
"Below Expectations" **47** stakeholders scored us as "below expectations". They were then asked the ESO needed to do to meet their expectations.	• **Solve a range of connections issues** – almost half of the feedback was received on this topic. Key issues raised by stakeholders included long waiting times for connections offers and poor or slow communication in providing connection updates and responses to queries. Some stakeholders also suggested we need to be more proactive in our decision making on connections. • **Engage more meaningfully and improve communication and transparency** – provide timely responses to queries and show better consideration of our stakeholders' point of view. • **Move faster** – specifically on network planning, network investment and modelling batteries on the grid.

Value for money

Under the ESO incentive arrangements for RIIO-2, the ESO must report on its outturn and forecast costs for each role against cost benchmarks. As the reporting for the Value for Money criterion relates to all 3 roles, we have brought this together in one section rather than providing a separate Value for Money chapter for each role. All figures in this section are in 2018-19 prices.

It is important to note that the Regulatory Reporting Pack (RRP) remains the formal cost report for the ESO. The reported spend to date for the 2023/24 reporting year has been reviewed as part of our normal monthly management review process but has not been formally audited or been subject to the formal governance process for submission that would normally be used for RRP reporting. The ESO uses the methodology, as set out in the ESORI guidance, to allocate costs to each role.

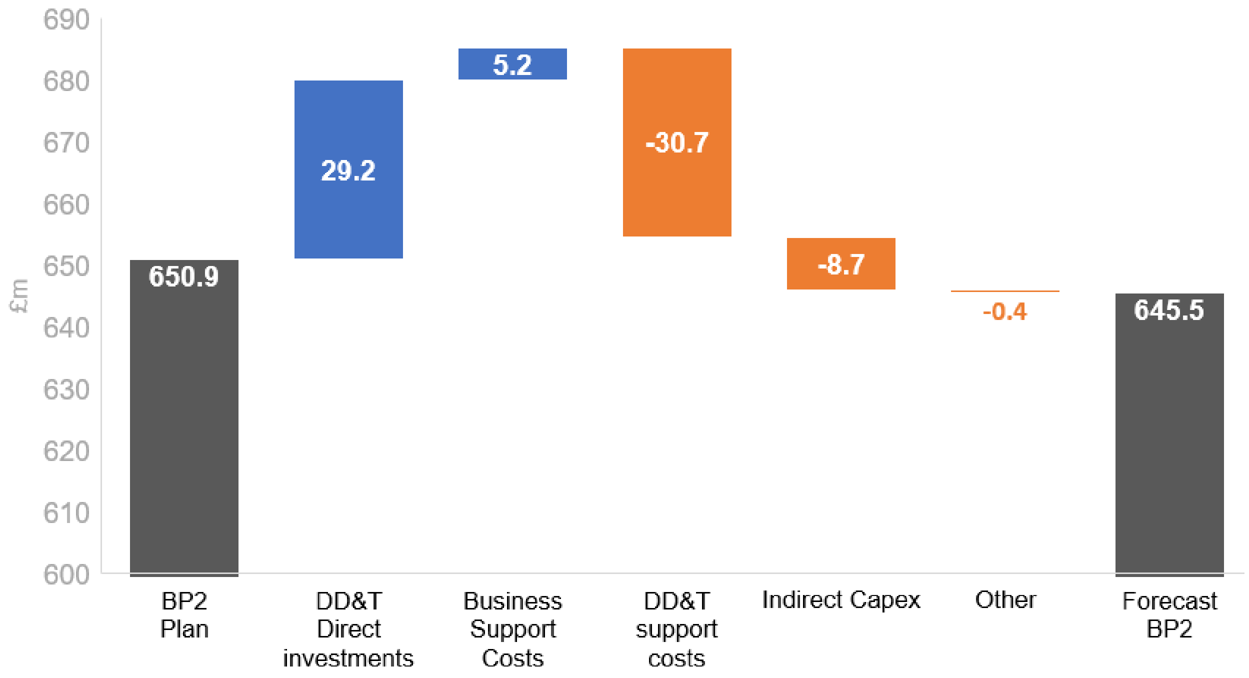
The following table sets out our spend to date and forecast for the RIIO-2 BP2 period, compared to the approved BP2 plan.

		Role 1	Role 2	Role 3	Total
BP2 plan	(£m)	313.6	176.2	161.0	**650.9**
Spend to date (up to end of September 2023)	(£m)	61.2	34.2	35.8	**131.1**
Forecast spend for remainder of BP2	(£m)	251.4	146.3	115.3	**514.5**
Forecast total spend for BP2	(£m)	312.5	182.0	151.0	**645.5**
Forecast deviation from BP2 plan	(£m)	-1.1	5.6	-9.9	**-5.4**
Forecast deviation from BP2 plan	%	**-0.3**	**3.2**	**-6.2**	**-0.8**

The figures in this table are made up of both directly and indirectly attributable costs.
See 'Cost Benchmark Summary' table at the end of this section for full breakdown of costs

Total forecast spend across the BP2 period is £645.5m, £5.4m lower than the £650.9m presented in our BP2 plan.

Total forecast ESO spend vs BP2 plan spend, with main variances



We are currently forecasting that our direct and supporting ESO costs will be in line with our BP2 plan based on YTD performance. In the first 6 months of the BP2 period we have increased headcount across all ESO functions by 99 FTE, which is slightly behind our plan. We have filled roles with contractors where appropriate and overall expect to be in line with our BP2 planned spend over the full period.

Our business support costs (excluding DD&T) are forecast to be slightly higher than the BP2 plan. As agreed with Ofgem we did not update these costs in our BP2 plan, so the planned costs remain at levels forecast in our RIIO-2 business plan. Our expected cost out turn is consistent with levels of spend in the BP1 period.

The key increase to BP2 plan expenditure is in the direct DD&T (Digital, Data and Technology) investment portfolio (+£29.2m) where underspend on projects in the BP1 period have been included in the expected spend for the rest of the RIIO-2 period. The significant reduction in the DD&T support cost is due to the expected increase in support costs driven through the delivery of new technology, being lower than forecast in our BP2 plan. Additional finance and property costs are the key drivers for the higher allocation of shared business support costs from National Grid.

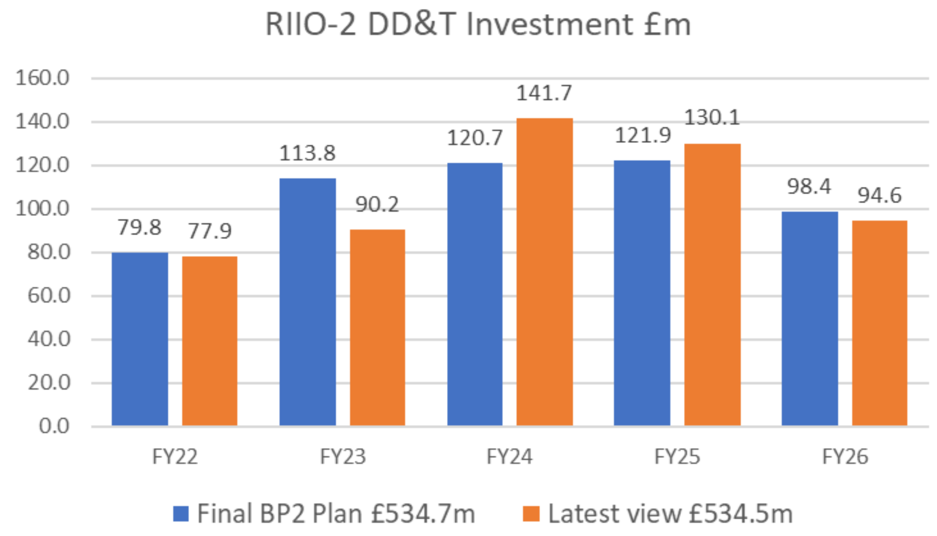
The main area of forecast update compared to our BP2 plan is in our direct DD&T investment plan. Over the last six months we have made changes to our investment sanctioning process to create a process that is quicker and easier to manage and, more importantly, gives greater governance, clarity and understanding of approvals across the portfolio and allows tracking of progress against the RIIO-2 plan, through our Portfolio Review Board (PRB).

The new sanctioning process approves investment as a 'whole life' commitment and through this process we have established the baseline of where all RIIO-2 investment projects currently stand to allow us to track performance going forward. A Change Management process has been developed to ensure appropriate governance and tracking of any changes to this established baseline.

Our forecast for direct DD&T investment is therefore based on the sanctioned values for all projects that have been baselined through the new sanctioning process. There are four projects which are yet to be sanctioned and for these investments, we have kept forecast values in line with our BP2 plan. We recognise the inherent uncertainty in our DD&T projects and our sanctioning process allows each project to sanction spend to cover this risk. As we continue to track projects across the portfolio, we will ensure that adjustments are made to risk values where it is prudent to do so.

Our final BP2 plan was submitted to Ofgem in August 2022. As such we included a forecast for the expected direct DD&T investment spend for 2022/23. Our actual spend for the BP1 period was £25.5m below that forecast in the BP2 plan. This underspend in BP1 can be largely attributed to the timing of spend on projects, so our new baseline forecast includes the re-phasing of spend across the final three years of the RIIO-2 period. For this reason, we present a view of 'whole life' project spend over the full RIIO-2 period, as well as the performance over only the BP2 period. This allows any overspend to the BP2 plan to be viewed in the context of the full RIIO-2 period when considering whether a project will deliver value for money.

The impact of the rephasing of investment spend is illustrated in the chart below:



Our forecast spend over the RIIO-2 period is £534.5m which is £0.2m below our BP2 plan. This breaks down further into an overspend in the BP2 period of £29.2m, offset by underspends in BP1 and 2025/26 of £25.5m and £3.8m respectively. Forecasts for each DD&T investment are summarised in the role sections below and show the variance against the BP2 approved plan as well as the five-year view of spend. Further detail at role and investment level can be found in the Cost Monitoring Framework (CMF) report summary which is appended to this report.

Support costs for DD&T are forecast to be £30.7m lower than our BP2 plan. Our BP2 plan included an additional £41.1m for incremental running costs which result from implementation of new technology. Our current view is that incremental costs will be lower and will be incurred later than outlined in our BP2 plan.

Directly attributable costs - by role

Please note that indirectly attributable costs are summarised in the next section.

Role 1 (Control centre operations) direct expenditure

For Role 1, we are currently forecasting to spend £10.4m over the BP2 plan for directly attributable costs.

Role 1	Category	BP2 Plan £m	Spend to Date £m	BP2 Forecast £m	Variance £m
	Role 1 Directly Attributable Opex	67.7	17.4	67.7	0.0
	Role 1 Investments	165.1	27.2	175.5	10.4
	Total	**232.8**	**44.6**	**243.4**	**10.4**

Whilst there are smaller variances to the BP2 plan across Role 1 direct investments the key driver of the £10.4m additional spend is the Balancing Programme[9]. The current Balancing Programme forecast spend for the full RIIO-2 period is £152.8m, which is only £0.6m higher than reported in our BP2 plan. However due to the re-phasing of cost our forecast for the BP2 period is £70.4m which is £11.9m higher than our BP2 plan.

ID	Investment name	BP2 Plan	*FY24 P1-P6 Actuals*	BP2 Forecast	Variance	RIIO-2 spend as per BP2	RIIO-2 Forecast	Variance
110	Network control	36.4	*4.8*	35.3	-1.1	58.1	57.8	-0.3
120	Interconnectors	4.3	*0.6*	2.8	-1.5	10.9	7.3	-3.6
130	Emergent technology and system management	3.9	*0.1*	3.2	-0.6	8.7	7.6	-1.1
140	ENCC operator console	2.8	*0.1*	3.0	0.2	5.5	5.4	-0.1
170	Frequency visibility	4.0	*0.2*	4.7	0.7	6.8	6.7	-0.1
180	Enhanced balancing capability	39.8	*9.9*	51.0	11.1	102.8	103.0	0.2
190	Workforce and change management tools	2.0	*-0.1*	2.0	0.0	3.8	3.7	0.0
200	Future training simulator and tools	4.4	*0.0*	4.4	0.0	7.3	7.3	0.0
210	Balancing asset health	10.1	*1.6*	10.0	-0.1	27.5	28.0	0.5
220	Data and analytics platform	15.1	*3.1*	15.5	0.4	29.9	30.4	0.5
240	ENCC asset health	5.8	*1.7*	5.3	-0.5	14.2	12.2	-2.0
250	Digital engagement platform	3.9	*3.3*	7.2	3.3	11.4	12.0	0.6
260	Forecasting enhancements	6.1	*0.6*	6.1	0.0	13.4	13.3	-0.1
450	Future innovation productionisation	4.0	*0.0*	4.0	0.0	6.6	6.6	0.0
460	Restoration	17.5	*0.1*	15.0	-2.5	24.9	21.7	-3.3
480	Ancillary services dispatch	2.4	*1.0*	3.3	0.9	8.5	8.4	-0.1
670	Real Time Prediction	0.0	*0.0*	0.0	0.0	0.0	0.0	0.0
	Wokingham ENCC	2.7	*0.0*	2.7	0.1	4.9	4.9	0.0
	Total	**165.1**	***27.2***	**175.5**	**10.4**	**345.3**	**336.4**	**-8.9**

Details of the cost variance drivers to the BP2 plan for specific IT investments in Role 1 can be found in the Cost Monitoring Framework appendix.

[9] *Includes investments: (180) Enhanced balancing capability, (210) Balancing asset health, (260) Forecasting enhancements, (480) Ancillary services dispatch*

Role 2 (Market development and transactions) direct expenditure

For Role 2, we are currently forecasting to spend £17.2m over the BP2 plan for directly attributable costs.

Role 2	Category	BP2 Plan £m	Spend to Date £m	BP2 Forecast £m	Variance £m
	Role 2 Directly Attributable Opex	39.1	7.0	39.1	0.0
	Role 2 Investments	56.4	10.5	73.6	17.2
	Total	**95.5**	**17.6**	**112.8**	**17.2**

Whilst there are smaller variances to the BP2 plan across Role 2 direct investments the key driver of the additional spend are EMR and CfD improvements (+£7.2m) and Settlements, Charging and Billing (+£9.7m). For these investments we are forecasting an overspend over the full RIIO-2 period of £9.0m and £9.4m respectively.

The BP2 plan for EMR and CfD improvements assumed that the new portal for Capacity Market would have gone live and that remaining spend would be for enhancements and regulatory updates. However, following a more detailed study of user requirements, an increase in complexity to deliver the solution and prioritisation of regulatory change implementation, a re-planning exercise was undertaken. This identified the best approach to maximising customer value and efficiency, whilst ensuring regulatory compliance and took the project forward with transparent and open engagement with our customers and stakeholders. This has driven the £9.0m additional cost compared to our BP2 plan.

In the BP2 submission, it was assumed that the main Settlements, Charging and Billing (STAR) releases would have gone live during BP1. However, costs have increased by £9.4m versus this position in light of new scope of work including mandatory regulatory and legislative changes, customer enhancements, and increased understanding of the complexity and unique nature of each service to transition onto STAR.

ID	Investment name	BP2 Plan	*FY24 P1-P6 Actuals*	BP2 Forecast	Variance	RIIO-2 spend as per BP2	RIIO-2 Forecast	Variance
270	EU regulation	9.4	*0.1*	9.7	0.3	22.3	19.8	-2.5
280	GB regulation	8.7	*0.3*	8.8	0.1	19.4	18.2	-1.2
320	EMR and CfD Improvements	7.4	*4.0*	14.5	7.2	21.3	30.4	9.0
330	Digitalised code management	2.5	*0.1*	2.8	0.3	2.7	2.8	0.2
400	Single markets platform	14.5	*0.3*	14.1	-0.4	34.9	33.4	-1.5
420	Auction capability	4.2	*1.0*	4.2	0.0	8.9	8.0	-0.9
610	Settlements, Charging and Billing	9.8	*4.7*	19.5	9.7	33.5	42.9	9.4
	Total	**56.4**	**10.5**	**73.6**	**17.2**	**143.0**	**155.5**	**12.5**

Details of the cost variance drivers to the BP2 plan for specific IT investments in Role 2 can be found in the Cost Monitoring Framework appendix.

Role 3 (System insight, planning and network development) direct expenditure

For Role 3, we are currently forecasting to spend £1.7m more over the BP2 plan for directly attributable costs.

Role 3	Category	BP2 Plan £m	Spend to Date £m	BP2 Forecast £m	Variance £m
	Role 3 Directly Attributable Opex	56.4	12.7	56.4	0.0
	Role 3 Investments	23.8	6.4	25.5	1.7
	Total	**80.2**	**19.2**	**81.9**	**1.7**

Spend for role 3 investments is forecast to be £47.5m over the full RIIO-2 period, which is £3.8m lower than our BP2 plan. The main driver of the £1.7m overspend in the BP2 period is the Offline network modelling project (+£2.0m) where there was a £1.4m underspend in BP1 carried across to BP2 due to the migration to Azure taking longer to complete.

ID	Investment name	BP2 Plan	*FY24 P1-P6 Actuals*	BP2 Forecast	Variance	RIIO-2 spend as per BP2	RIIO-2 Forecast	Variance
340	RDP implementation and extension	7.7	*1.8*	7.0	-0.7	17.1	13.1	-4.0
350	Planning and outage data exchange	3.3	*0.5*	2.9	-0.3	8.4	8.1	-0.3
360	Offline network modelling	3.5	*1.0*	5.4	2.0	8.1	8.6	0.5
380	Connections platform	3.0	*0.8*	3.7	0.7	7.0	7.5	0.5
390	NOA enhancements	6.0	*2.0*	6.0	0.0	9.3	8.8	-0.5
500	Zero carbon operability	0.2	*0.2*	0.2	0.0	1.2	1.3	0.0
650	Accelerating whole electricity flexibility	0.1	*0.0*	0.1	0.0	0.1	0.1	0.0
	Total	**23.8**	***6.4***	**25.5**	**1.7**	**51.3**	**47.5**	**-3.8**

Details of the cost variance drivers to the BP2 plan for specific DD&T investments in Role 3 can be found in the Cost Monitoring Framework appendix.

Indirectly attributable costs - across all roles

Our assessment for value for money is not only based on costs which are directly driven by activities within a particular role. Some activities support all roles equally and a summary of these costs and our forecast against the BP2 plan is given below.

Please note that, as agreed with Ofgem, there was no update to the BP2 plan for costs which are allocated by National Grid to its regulated entities where services or projects are shared across the National Grid group. Therefore, for capex, business support (excluding IT & telecoms) and other price control costs all values for BP2 are based on RIIO-2 final determinations. DD&T costs were revised in our BP2 submission only to reflect the expected incremental support costs driven by our investment portfolio.

	Activity	BP2 Plan £m	Spend to Date £m	BP2 Forecast £m	Variance £m
	ESO Supporting Opex	16.5	4.4	16.5	0.0
	Indirectly Attributable Capex	32.0	7.6	23.3	-8.7
	Total Business Support	166.7	32.1	141.2	-25.5
Business Support sub-categories	IT & telecoms	133.8	22.3	103.0	-30.7
	Property management	11.4	3.2	12.8	1.4
	HR & non-operational training	4.8	1.0	5.3	0.4
	Finance, audit & regulation	6.6	3.0	9.3	2.7
	Insurance	1.8	0.3	1.3	-0.5
	Procurement	1.4	0.2	1.5	0.0
	CEO & group management	6.8	2.2	8.0	1.2
	Other Price Control Costs	27.1	5.6	26.7	-0.4
	Total	**242.3**	**49.7**	**207.7**	**-34.6**

Overall, our forecast indirectly attributable costs are £34.6m lower than the BP2 plan.

Our ESO supporting opex costs relate to ESO's Business Change, Innovation, Assurance, Regulation and Customer teams. We currently expect these costs to be in line with our BP2 plan.

Indirectly attributable capex costs relate to Business Services systems, Hosting, IT Operations and Tooling, Infrastructure, Enterprise Data Networks and End User Computing as well as spend on property. The lower forecast cost compared to our BP2 plan is largely driven by lower investment requirements for business network infrastructure (-£3.2m) and lower Wokingham property investment (-£2.7m).

Most business support costs continue to relate to DD&T costs which support our diverse and complex CNI and non-CNI applications as well as the costs associated with application development, networks, and end user computing. DD&T costs include underlying support costs and an estimate of incremental support costs which are driven by the delivery of new technology through our DD&T investment portfolio. Lower DD&T costs over the BP2 period are due to lower investment driven incremental run costs, which were forecast to be £41.1m for the BP2 period.

Other Business Support costs are currently expected to be £5.2m higher than the BP2 plan. The main drivers are:

Finance, Audit & Regulation (+£2.7m) – higher forecast cost is due to higher volume of work in business services largely relating to increasing business headcount.

Property management costs (+£1.4m) – increase in costs across is driven by higher utility costs (allocated cost forecasts were not updated for BP2).

Cost benchmark summary

Funding Category	BP2	2023/24 Spend to Date	Total 2023/24 Forecast	2024/25 Forecast	Total	Variance
Total Price Control Costs						
Total Role 1 Costs	313.6	61.2	156.9	155.7	312.5	- 1.1
Total Role 2 Costs	176.3	34.2	89.7	92.2	182.0	5.6
Total Role 3 Costs	161.0	35.8	73.6	77.4	151.0	- 9.9
Total Price Control Costs	**650.9**	**131.1**	**320.2**	**325.3**	**645.5**	**- 5.4**
Role 1						
ESO Opex	67.7	17.4	33.6	34.2	67.7	0.0
Capex	141.4	23.4	75.4	67.5	143.0	1.6
BSC	23.7	3.8	15.6	17.1	32.6	8.9
Total Directly Attributable to Role 1	**232.8**	**44.6**	**124.6**	**118.8**	**243.4**	**10.4**
ESO Opex	5.5	1.5	2.7	2.8	5.5	- 0.0
Capex	10.7	2.5	3.3	4.4	7.8	- 2.9
BSC	55.6	10.7	21.9	25.2	47.0	- 8.5
Other Price Control Costs	9.0	1.9	4.4	4.5	8.9	- 0.2
Total Indirectly Attributable to Role 1	**80.8**	**16.6**	**32.3**	**36.8**	**69.2**	**- 11.6**
Role 2						
ESO Opex	39.1	7.0	18.9	20.2	39.1	0.0
Capex	43.4	9.6	31.4	29.5	60.9	17.5
BSC	13.0	1.0	7.0	5.6	12.7	- 0.3
Total Directly Attributable to Role 2	**95.5**	**17.6**	**57.4**	**55.4**	**112.8**	**17.2**
ESO Opex	5.5	1.5	2.7	2.8	5.5	- 0.0
Capex	10.7	2.5	3.3	4.4	7.8	- 2.9
BSC	55.6	10.7	21.9	25.2	47.0	- 8.5
Other Price Control Costs	9.0	1.9	4.4	4.5	8.9	- 0.2
Total Indirectly Attributable to Role 2	**80.8**	**16.6**	**32.3**	**36.8**	**69.2**	**- 11.6**
Role 3						
ESO Opex	56.4	12.7	27.8	28.6	56.4	- 0.0
Capex	20.2	5.7	12.3	10.6	22.8	2.6
BSC	3.5	0.8	1.2	1.4	2.7	- 0.9
Total Directly Attributable to Role 3	**80.2**	**19.2**	**41.3**	**40.6**	**81.9**	**1.7**
ESO Opex	5.5	1.5	2.7	2.8	5.5	- 0.0
Capex	10.7	2.5	3.3	4.4	7.8	- 2.9
BSC	55.6	10.7	21.9	25.2	47.0	- 8.5
Other Price Control Costs	9.0	1.9	4.4	4.5	8.9	- 0.2
Total Indirectly Attributable to Role 3	**80.8**	**16.6**	**32.3**	**36.8**	**69.2**	**- 11.6**

Appendix: Cost Monitoring Framework

Q1-Q2 2023-24 Summary

Cost Monitoring Framework (Q1-Q2 2023-24 Summary)

Overview of the Cost Monitoring Framework (CMF)

Following our Business Plan 2 (BP2) submission, Ofgem outlined the requirement for a Cost Monitoring Framework (CMF). The objective of the CMF is to provide visibility of our BP2 Digital, Data and Technology (DD&T) delivery progress and cost management, and the value being delivered across the BP2 DD&T investment portfolio. It also provides transparency of DD&T key achievements, risks and strategic decisions.

The RIIO-2 incentives scheme is the framework Ofgem uses to assess our performance against our RIIO-2 business plan and associated BP2 delivery schedule milestones. Separately, the CMF reports against our BP2 DD&T Annex 4 delivery roadmaps with its own schedule of DD&T-specific milestones. The CMF is not used directly to assess our performance, however, may be used as evidence as part of our 'Value for Money' assessment.

Our DD&T investments are critical enablers for many of our RIIO-2 deliverables, and it is important to understand dependencies between them. Our published BP2 delivery schedule provides a high-level view of where DD&T investments and BP2 deliverables are related to one another.

As per the Electricity System Operator Reporting and Incentives Arrangements (ESORI), we are required to provide quarterly reports directly to Ofgem as part of the CMF. We feel it is important to share updates with our external stakeholders and industry as part of the framework. So, we'll be including a summary of the CMF update every six months alongside our incentives reporting.

The remainder of this appendix provides a summary of the first six months of the CMF across our DD&T investment portfolio and includes:

- **Delivery performance** – covering main achievements during the last six months and plans for the next three months.
- **Governance outputs** – an overview of current main delivery risks/issues plus key strategic decisions taken in last six months.
- **Cost performance** – a comparison of BP2 submission vs latest approved spending profiles.

High-Level Portfolio Summary (Q1-Q2 2023-24)

Following confirmation of CMF requirements with Ofgem, we have developed our internal CMF reporting governance and processes to enable a regular quarterly reporting cadence. In line with Ofgem's requirements, we have also provided detail on our governance processes as part of this reporting exercise in order to showcase the due process that is being followed as part of our ongoing portfolio management processes (e.g. inclusion of strategic decision making within the quarter, reference to change request processes).

During these 6 months, we revised our sanctioning processes, moving to a whole life sanctioning methodology. The benefit of this is to give clarity and create visibility of tracking against the whole of the project and to understand the investment fully. Through this process we have established the baseline of where all RIIO-2 investment projects currently stand to allow us to track performance going forward. In parallel a Change Management process has been developed to ensure better governance and tracking of any changes to this established baseline to ensure visibility of progress within the portfolio. As of 30 September 2023, 26 investments out of the 32 have been through the sanctioning process.

Per latest Approved Spend figures, our latest sanctioned position is £19.5M above our BP2 submission overall. Please note that some investments in this role are yet to be sanctioned and as such have not been included in our latest approved spend position. As such reported over/underspend in the Value for Money section of the incentives report will differ as it includes forecast spend for projects which have yet to be sanctioned.

Our actual spend for the BP1 period was £25.5m below that forecast in the BP2 plan for the same period. This underspend in BP1 can be largely attributed to the timing of spend on projects, so our latest approved spend position includes the re-phasing of spend across the final three years of the RIIO-2 period. Further detail on cost variance at a role level is detailed in next role sections.

We are looking into feasibility of deploying our Critical National Infrastructure (CNI) into the Cloud. Looking at other portfolio areas, we are assessing the feasibility of deploying our Critical National Infrastructure (CNI) into the Cloud. We are progressing proof of concepts in this space with our partners.

We have expanded support for enhanced Ways of Working by driving forward the development of an Agile Transformation Office. We have started building this capability, including the establishment of a DevSecOps Engineering Centre of Excellence (CoE) in phase 1 and the hiring of engineering subject matter expert contractors.

At portfolio level we also kicked off investigation of Technology Business Management (TBM) cost definition utilising Apptio tooling, working with the TBM Council and other energy organisations to define the first draft of a Utilities Business Services taxonomy extension.

Role 1 (Control centre and operations)

Role 1 summary

Executive summary	We keep progressing all our investments, whilst 4 remain to be fully mobilise and approve related spend as per BP2 submission plan. We have made key strategic decisions in Network Control to ensure we negate the need for a full second project to complete deployment to GridOS within the next 10 years. We have also decided to progress with implementation of a tool following the Scotland oscillations witnessed.

The next financial table shows the role 1 current position. It shows our BP2 submission figures for FY24 and FY25, and the same years are shown for the approved values through our whole life sanctioning process in "Approved BP2 Spend".

Latest DD&T role spend	**£m**	**FY24**	**FY25**	**Total**
	BP2 Submission	80.9	81.6	162.5
	Approved BP2 Spend	85.5	76.9	162.4
Rationale	"Approved BP2 Spend" for Role 1 is currently in line with the BP2 submission, however as mentioned above, 4 investments are yet to be sanctioned and as such have not been included in "Approved BP2 Spend". These can be found in the investment summary details. Reported over/underspend in Value for Money will differ as it includes projects which have yet to be sanctioned.			

Investment summary

Investment summaries are organised in line with programme delivery groupings

110 Network Control						
Delivery update	We made a strategic decision to align with the evolving product roadmap from General Electric (GE) and are moving to the Grid OS platform from GE in the network control programme. This was done to de-risk technical obsolescence and gain flexibility for the future. As a result, Network Control Management System (NCMS) has been delayed by 6-months (Mar-25 to Oct-25) as per the GridOS roadmap timelines from GE. This decision will negate the need for a full second project to complete deployment to GridOS within the next 10 years. We believe that from a cost benefit perspective it continues to deliver value to the customer. **Achievements over last 6 months:** 1. Deployed the Reliance and Wide area monitoring system (WAMS) to GE cloud environment and tested the features. 2. Signed off network design for circuit connectivity to GE On-Prem Environment connectivity. 3. Finalisation of key interface requirements & smoke testing commenced in AWS environment. 4. CIM (Common Information Model) requirements gathered for integration of NCMS with Offline Transmission Analysis (OLTA).					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£36.4m	**BP2 submission with BP1 under/overspend**	£36.1m	**Approved Spend**	£35.3m
	FY22 to FY26 Period					
	BP2 Submission	£58.1m		**Approved Spend**	£57.8m	
	The variance in actuals relates to non-utilisation of risk (£2.4m FY24), reprofiling FY24 spend to subsequent quarters and delivery efficiencies.					

<table>
<tr><th colspan="7">170 Frequency Visibility</th></tr>
<tr><td>Delivery update</td><td colspan="6">Replacement FATE (Frequency and Time Error) platform delivery date moved from FY23 Q4 to FY24 Q4 due to complexities of designing into existing Data Centres and restrictions of operating within our existing Data Centres. Following the Scotland oscillations witnessed on the transmission network we are looking to deploy Reactive's “Oscillation Guard Pro”, their new Oscillation Detection system. This deployment will enable increased visibility.

Achievements over last 6 months:
5. Completed network configuration across both non-production and production environments, to enable Frequency and Time Error (FATE) deployment and necessary access.
6. Deployment of FATE base functionality, Time Error and Cluster WAMS Archive across non-production environments, including integration of Phasor Data Concentrator (PDC), Automated Essentials (AE) and Wide Area Monitoring System (WAMS).
7. New universal service established for Data Historian (DH) interface, configured, and tested within non-production environment.</td></tr>
<tr><td rowspan="5">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£4.0m</td><td>BP2 submission with BP1 under/overspend</td><td>£4.8m</td><td>Approved Spend</td><td>£4.7m</td></tr>
<tr><td colspan="6">FY22 to FY26 Period</td></tr>
<tr><td>BP2 Submission</td><td colspan="2">£6.8m</td><td>Approved Spend</td><td colspan="2">£6.7m</td></tr>
<tr><td colspan="6">Variance attributed to a reprofiling of underspend from BP1 to BP2 and delays to FATE.</td></tr>
</table>

<table>
<tr><th colspan="7">180 Enhanced Balancing Capabilities</th></tr>
<tr><td>Delivery update</td><td colspan="6">We have made the decision to implement Quick and Slow reserve in the Open Balancing Platform (OBP). The implementation will be split into support for BMU and non-BMU. We are currently waiting for technical requirements to be finalised to enable its addition to delivery roadmap. This means we are saving on implementation cost and effort required. This mitigates extra costs in Balancing Mechanism (BM) and Ancillary Service Dispatch Platform (ASDP) systems, and to integrate the changes later with OBP.

Achievements over last 6 months:
8. Delivery continued across planned Programme Increments for Enhanced Balancing Capabilities, in addition to the mobilisation of a new project to identify and implement a solution to replace Public Switched Telephone Network (PSTN) and Integrated Services for Digital Network (ISDN) within ESO.
9. Completed Balancing Transformation Programme Increment (PI) 7 and 8.</td></tr>
<tr><td rowspan="5">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£39.8m</td><td>BP2 submission with BP1 under/overspend</td><td>£47.2m</td><td>Approved Spend</td><td>£51.0m</td></tr>
<tr><td colspan="6">FY22 to FY26 Period</td></tr>
<tr><td>BP2 Submission</td><td colspan="2">£102.8m</td><td>Approved Spend</td><td colspan="2">£103.0m</td></tr>
<tr><td colspan="6">Scope from BP1 (CNI DC Strategic Delivery) deferred to BP2, therefore associated underspend budget in BP1 period carried into BP2 to enable this delivery.</td></tr>
</table>

<table>
<tr><th colspan="7">210 Balancing Asset Health</th></tr>
<tr><td>Delivery update</td><td colspan="6">We have delivered asset health activities, including control room improvements, whist also delivering benefits via Constraints Management Pathfinder. Our releases also supports our retirement plan for EBS. We have also started enabling work for interface from the Balancing Mechanism and Open Balancing Platform.

Achievements over last 6 months:
10. In addition to various Asset Health and Control Room improvements, we enabled the Control Room to manage Constraint Management Pathfinder Units (an enabler for £30m annual benefit).
11. Furthermore, the migration of EBS functionality continued, through the enablement of Short-Term Operating Reserve (STOR) data to be imported to BM without reliance on EBS system
12. EWIC and Moyle interconnectors moved from legacy systems.</td></tr>
<tr><td rowspan="2">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£10.1m</td><td>BP2 submission with BP1 under/overspend</td><td>£11.4m</td><td>Approved Spend</td><td>£10.0m</td></tr>
</table>

	FY22 to FY26 Period					
	BP2 Submission	£27.5m		**Approved Spend**	£28.0m	

480 Ancillary Services Dispatch						
Delivery update	We have delivered 2 releases which have enabled Regional Development Programme (RDP) for NGED whilst supporting asset health and control room improvements. In parallel we have started enabling work for Regional Development Programme (RDP) for UKPN. Additionally, we are creating our retirement strategy for Ancillary Services Dispatch Platform (ASDP).					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£2.4m	**BP2 submission with BP1 under/overspend**	£4.3m	**Approved Spend**	£3.3m
	FY22 to FY26 Period					
	BP2 Submission	£8.5m		**Approved Spend**	£8.4m	
	Scope from BP1 (to enable Regional Development Programmes (RDP) and Ancillary Services Reform (ASR)) deferred to BP2, therefore associated underspent budget in BP1 carried into BP2. This also means we are required to increase the lifespan of the ASDP platform further than originally anticipated.					

670 Real Time Predictions						
Delivery update	Investment has now been mobilised.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£0m	**BP2 submission with BP1 under/overspend**	£0m	**Approved Spend**	£0m
	FY22 to FY26 Period					
	BP2 Submission	£0m		**Approved Spend**	£0m	

260 Forecasting Improvements						
Delivery update	We are working to leverage Grid Supply Point (GSP) on Oracle Cloud Infrastructure. This will accelerate delivery of consumer benefits (£28m). **Achievements over last 6 months:** 13. Successful Early Lifecycle Support (ELS) exit during April 23 (with expected consumer benefit of £17m) and the Local Constraints Market (LCM) Forecasting Implementation which took place in June 23.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£6.1m	**BP2 submission with BP1 under/overspend**	£6.8m	**Approved Spend**	£6.1m
	FY22 to FY26 Period					
	BP2 Submission	£13.4m		**Approved Spend**	£13.3m	

220 Data and Analytics Platform						
Delivery update	A decision has been made to move to a capability-driven delivery approach and away from individual use case delivery. The long-term impact is that the velocity for onboarding will be significantly increased but the short-term impact is that it introduces risk of delay to integration with some other programmes. **Achievements over last 6 months:** 14. DAP 2.0 Proof of Concept (PoC) completed – supporting continuous investigation of alternative technologies and successful deployment of Release 3 for Data Portal.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£15.1m	**BP2 submission with BP1 under/overspend**	£15.8m	**Approved Spend**	£15.5m

	FY22 to FY26 Period			
	BP2 Submission	£29.9m	**Approved Spend**	£30.4m

510 Restoration & Restoration Decision Support Tool						
Delivery update	We have reviewed our milestones and roadmap and aligned these with the delivery activities specific to the "Inter-control Centre Communications Protocol" (ICCP) comms links being delivered with each DNO. We are also preparing a Request for Proposal (RFP) for our Restoration tool, following on from the recent Pre-Qualification Questionnaire (PQQ). **Achievements over the last 6 months:** 15. Requirements refined with stakeholders and fed into the PQQ which has been launched, reviewed, and scored by the project team to enable the RFP activities. 16. Feasibility analysis completed for the implementation of the ICCP links across the various DNOs.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£17.5m	**BP2 submission with BP1 under/overspend**	£17.9m	**Approved Spend**	£15.0m
	FY22 to FY26 Period					
	BP2 Submission	£24.9m		**Approved Spend**	£21.7m	
	Lower level of investment required to ensure new Restoration service providers have resilient communication and control infrastructure.					

130 Emerging Technology and System Management						
Delivery update	We have included a New Voltage (Pennines) feature (FY24 Q4) which will see a minor cost increase but absorbed within our BP2 submission. Constraint Management Pathfinder (CMP) Feature was descoped following changes in the CMP service design. **Achievements over last 6 months:** 17. Development of Forecast parameterisation to enable 5-minute level of granularity and extends the study period from 24 hours to 48 hours ahead. 18. Constraints pathfinder **-** provided better situational awareness and visibility of the options available to Electricity National Control Centre (ENCC) plus generators status and instructions. 19. Stability Pathfinder - Reporting functionality delivered, to support publishing performance and usage of the Stability Pathfinder contracts to the ESO Portal.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£3.9m	**BP2 submission with BP1 under/overspend**	£4.2 m	**Approved Spend**	£3.2m
	FY22 to FY26 Period					
	BP2 Submission	£8.7m		**Approved Spend**	£7.6m	

250 Digital Engagement Platform						
Delivery update	**Achievements over last 6 months:** 20. Features delivered included menu enhancements, Calendar Events, Asset Management and content search, maps enhancements, page layout enhancements, Taxonomy Management and enhanced search capabilities and single sign on capability for internal users.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£3.9m	**BP2 submission with BP1 under/overspend**	£4.9 m	**Approved Spend**	£7.2m
	FY22 to FY26 Period					
	BP2 Submission	£11.4m		**Approved Spend**	£12.0m	
	Change in spend profile, with scope from BP1 deferred to BP2, therefore associated underspent budget in BP1 carried into BP2. Also, some scope and related spend brought forward from FY26.					

190 Workforce Change Management Tools						
Delivery update	We have mobilised the next phase to implement a solution to enable an automated system for shift scheduling, personalised training, and compliance monitoring. In the meantime, we have also finalised high level requirements with the software service provider for the key deliveries for 2025.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£2.0m	**BP2 submission with BP1 under/overspend**	£2.0m	**Approved Spend**	£0m
	FY22 to FY26 Period					
	BP2 Submission	£3.8m		**Approved Spend**	£3.7m	

200 Future Training Simulator and Tools						
Delivery update	We have completed the high level scoping and identified at high level impacts of internal and external utilisation of the training simulator with industry and DNO/DSOs.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£4.4m	**BP2 submission with BP1 under/overspend**	£4.4m	**Approved Spend**	£0m
	FY22 to FY26 Period					
	BP2 Submission	£7.3m		**Approved Spend**	£7.3m	

240 ENCC Asset Health						
Delivery update	We have made a number of implementations including: 21. Scottish & Southern Energy Plug in (PI) Upgrade design Complete 22. Offline Stability Assessment Tool replacement (ASAT) 23. Interconnector Data Exchange (IDX) database and Operating system upgrade 24. MODIS Service operating model refresh 25. Video Wall Support Contract Extension (July) 26. Control Room Windows 10 Operating System Migration / PC replacement started					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£5.8m	**BP2 submission with BP1 under/overspend**	£6.7m	**Approved Spend**	£5.3m
	FY22 to FY26 Period					
	BP2 Submission	£14.2m		**Approved Spend**	£12.2m	

450 Future Innovation Productionisation						
Delivery update	Dynamic Reserve Setting formally ingested into DAP for assessment and delivery. We also decided to productionise module WP3 (the RISK module) of Optimal Outage Planning system.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£4.0m	**BP2 submission with BP1 under/overspend**	£4.0m	**Approved Spend**	£0m
	FY22 to FY26 Period					
	BP2 Submission	£6.6m		**Approved Spend**	£6.6m	

<table>
<tr><th colspan="7">140 ENCC Operator Console</th></tr>
<tr><td>Delivery update</td><td colspan="6">EPRI (Electric Power Research Institute) mobilised to undertake a requirements review and develop conceptual mock-up diagrams for the control desk visualisation. Outcomes of this engagement will support further stakeholder engagements and procurement activities.

Pre-Qualification Questionnaire (PQQ) documentation and associated questions drafted, reviewed and signed-off.</td></tr>
<tr><td rowspan="5">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£2.8m</td><td>BP2 submission with BP1 under/overspend</td><td>£3.1m</td><td>Approved Spend</td><td>£3.0m</td></tr>
<tr><td colspan="6">FY22 to FY26 Period</td></tr>
<tr><td>BP2 Submission</td><td colspan="2">£5.5m</td><td>Approved Spend</td><td colspan="2">£5.4m</td></tr>
<tr><td colspan="6">The variance above is attributed to a reprofiling of underspend from BP1 to BP2.</td></tr>
</table>

Role 2 (Market development and transactions)

Role 2 summary

Executive summary	We have made key strategic decisions in Single Markets Platform on integration with other platforms to avoid duplication of work with FSO planned activities. We have also decided to delay the delivery of our new slow and quick reserve to facilitate their implementation in our enduring systems. On EMR, we have realigned the BP2 roadmap to new delivery roadmap and milestones. In Settlements, Charging and Billing we delayed decommissioning of our legacy systems until BSUoS reform is completed. We also decided to place Issue 95 on hold until Elexon has completed design to avoid unnecessary spend.

The next financial table shows the role 2 current position. It shows our BP2 submission figures for FY24 and FY25, and the same years are shown for the approved values through our whole life sanctioning process in “Approved BP2 Spend”.

<table>
<tr><td rowspan="3">Latest DD&T role spend</td><td>£m</td><td>FY24</td><td>FY25</td><td>Total</td></tr>
<tr><td>BP2 Submission</td><td>27.6</td><td>28.8</td><td>56.4</td></tr>
<tr><td>Approved BP2 Spend</td><td>38.4</td><td>35.2</td><td>73.6</td></tr>
<tr><td>Rationale</td><td colspan="4">“Approved BP2 Spend” for Role 2 is currently £17.2m higher than the BP2 submission, however this variance includes £5.5m of underspend from BP1. This underspend would have been mainly attributed to the timing of spend on projects.

The remaining £11.7m of increased spend is driven in the main by EMR and Settlements, Charging and Billing investments.

The new EMR plan, has resulted in a cost increase compared to BP2 estimates. This replan was required to enable end-to-end familiarisation before switching from the legacy portal. Settlements, Charging and Billing also increased their forecasts considering the deferred items from BP1 to be delivered in BP2 and the new scope of work including mandatory regulatory/legislative changes and customer enhancements.</td></tr>
</table>

Investment summary

<table>
<tr><td colspan="7">320 EMR and CfD improvements</td></tr>
<tr><td>Delivery update</td><td colspan="6">We have realigned the BP2 roadmap to new delivery roadmap and milestones. 1 year delay to operational go live for Capacity Market (CM) (July 24) and increase in overall cost to deliver of £9.3m to end of FY26. Contracts for Difference (CfD) to be reviewed post Review of electricity market arrangements (REMA).

Achievements over last 6 months:
27. Features delivered include Creation and Release, Change of Address, Secure Message, Security Interest, Individual and Joint Unproven Disaster Security Recovery Test certificate request, Notify Components.</td></tr>
<tr><td rowspan="6">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£7.4m</td><td>BP2 submission with BP1 under/overspend</td><td>£6.4m</td><td>Approved Spend</td><td>£14.5m</td></tr>
<tr><td colspan="6">FY22 to FY26 Period</td></tr>
<tr><td>BP2 Submission</td><td colspan="2">£21.3m</td><td>Approved Spend</td><td colspan="2">£30.4m</td></tr>
<tr><td colspan="6">Enhanced understanding of business requirement and the complexities of the EMR regulations and rules has resulted in a replan, moving operational go live to Q2 FY25 to enable end-to-end familiarisation before switching from the legacy portal. Continued support of legacy portal in FY24 including regulatory changes, alongside developing the new portal has resulted in this cost increase in FY24 and FY25 compared to BP2 estimates.</td></tr>
</table>

	Delivery options reviewed and feature delivery roadmap agreed in Ofgem Deep-dives January 23, delivering new CM portal by Q1 FY25 with ongoing enhancements including Regulatory changes.

400 Single Markets Platform						
Delivery update	We have had to integrate CIAM (single sign on capability) with Single Markets Platform (SMP) by an interim solution for handling duplicate accounts. This means a limited number of customers will not be able to benefit from single sign on capability until this is resolved. In order to mitigate the potential for duplication of work in System Design due to FSO rebranding needs, we have decided to change of delivery date from Q3 FY24 to Q3 FY25 of the start of integration with Strategic Platforms milestone. This work has been replaced with Balancing Reserve additional functionality delivery, and as such there is no cost impact overall. Given the complexity of the new service designs, we have decided to re-evaluate our implementation options between legacy and future systems. This means that currently there is a delay to the delivery of the new Reserve reform products, Slow and Quick Reserve – originally planned for October and November 2023. We are actively working on an implementation plan. **Achievements over last 6 months:** SMP has delivered 7 features into production, including: Service Catalogue, Contract Management, EAC readiness for consuming Platform Events and Minor changes to Account Data Model to enable EAC and automatically convert every auction result into a Contract, Single-Sign-On solution (CIAM) for external customers to access the Single Markets Platform from the Digital Engagement platform. We also enhanced 3 existing features (APIs, Service Catalogue, DAP Integration), added UK Power Networks (UKPN) on the existing Regional Development Programmes (RDP) service and delivered Demand Flexibility Service (DFS) day 2. Ancillary Services Reform provided enhancements for internal users to improve their situational awareness of available response units.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£14.5m	**BP2 submission with BP1 under/overspend**	£15.9m	**Approved Spend**	£14.1m
	FY22 to FY26 Period					
	BP2 Submission	£34.9m		**Approved Spend**	£33.4m	

420 Auction Capability						
Delivery update	Development of the auction platform and the integration services is now complete and we are on track to open the platform for market participants to register for the first auction from 19 October 2023, with the first auction planned for 02 November 2023. **Achievements over last 6 months:** 28. Deployment of user interface and user authentication, Integration with other ESO systems complete (e.g., Single Markets Platform (SMP), Data Portal, Balancing Mechanism (BM), Ancillary Services Dispatch Platform (ASDP), Settlements). 29. EBR (Electricity Balancing Regulation) Consultation documents submitted, and comments addressed which will confirm industry approval for planned market changes prior to go live					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£4.2m	**BP2 submission with BP1 under/overspend**	£5.1m	**Approved Spend**	£4.2m
	FY22 to FY26 Period					
	BP2 Submission	£8.9m		**Approved Spend**	£8.0m	

610 Settlements, Charging and Billing	
Delivery update	A decision has been made to postpone delivery of "BSUoS Migration & Reform" from Q4 FY23 to Q2 FY25 and "Decommission CAB" from Q4 FY24 to Q3 FY25. Legacy systems will need to operate and be supported until old methodology concludes in Q2 FY25, leading to continued CAB support costs to the business. We have also postponed delivery of Frequency Response due to delays with Mandatory Frequency Response (MFR) feature. Delayed process efficiency and business value due to the continued compliance risk of manual workarounds and process.

	Achievements over last 6 months: 30. Completion of Early Life Support for Revenue regulatory release, including Disaster Recovery. 31. Release of: AAHEDC (BEIS) mandatory legislative change, Self-Invoicing Solution, HMRC mandatory tax change, Inter-TSO compensation charges (ITC).					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£9.8m	**BP2 submission with BP1 under/overspend**	£9.7m	**Approved Spend**	£19.5m
	FY22 to FY26 Period					
	BP2 Submission	£33.5m		**Approved Spend**	£42.9m	
	Increased FY24/25 forecasts considering the deferred items from BP1 to be delivered in BP2 and the new scope of work including mandatory regulatory/legislative changes and customer enhancements.					

330 Digitalised Code Management						
Delivery update	We have sent an RFP and reviewed replies from it.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£2.5m	**BP2 submission with BP1 under/overspend**	£2.6m	**Approved Spend**	£2.8m
	FY22 to FY26 Period					
	BP2 Submission	£2.7m		**Approved Spend**	£2.8m	
	Overall forecast refined post request for proposal (RFP) with a more informed perspective on likely cost of delivery.					

280 GB regulation						
Delivery update	We have started delivery phase for the SAAIO14 File Upgrade Project. We also decided to place Issue 95 on hold until Elexon has completed design to avoid unnecessary spend.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£8.7m	**BP2 submission with BP1 under/overspend**	£10.0m	**Approved Spend**	£8.8m
	FY22 to FY26 Period					
	BP2 Submission	£19.4m		**Approved Spend**	£18.2m	

270 Role in Europe						
Delivery update	We continue the implementation of the PCN and RSC Services Project.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£9.4m	**BP2 submission with BP1 under/overspend**	£12.1m	**Approved Spend**	£9.7m
	FY22 to FY26 Period					
	BP2 Submission	£22.3m		**Approved Spend**	£19.8m	

Role 3 (System insight, planning and network development)

Role 3 summary

Executive summary	Our work on External Data Exchange (EDE) Replacement has progressed steadily alongside the external progress of GC0139. A decision was made to place the DD&T Generation Export Management System (GEMS) project on hold. We reached and implemented an agreement with National Grid Electricity Transmission (NGET) to create a separate NGET instance of OLTA on the ESO platform. We have developed a new roadmap for Connections platform with customers. Network Innovation Allowance contracts were on Enhanced Frequency Control and we are now planning delivery activities with vendor.

The next financial table shows the role 3 current position. It shows our BP2 submission figures for FY24 and FY25, and the same years are shown for the approved values through our whole life sanctioning process in “Approved BP2 Spend”.

<table>
<tr><td rowspan="3">Latest DD&T role spend</td><td>£m</td><td>FY24</td><td>FY25</td><td>Total</td></tr>
<tr><td>BP2 Submission</td><td>12.2</td><td>11.6</td><td>23.8</td></tr>
<tr><td>Approved BP2 Spend</td><td>13.4</td><td>12.0</td><td>25.4</td></tr>
<tr><td>Rationale</td><td colspan="4">“Approved BP2 Spend” for Role 3 is currently £1.6m higher than the BP2 submission, however this variance includes £3.5m of underspend from BP1. This underspend would have been mainly attributed to the timing of spend on projects.</td></tr>
</table>

Investment summary

<table>
<tr><td colspan="7">340 RDP Implementation and Extension</td></tr>
<tr><td>Delivery update</td><td colspan="6">A decision was made to place the DD&T Generation Export Management System (GEMS) project on hold due to Scottish Power Transmission (SPT) being unable to deliver a solution as detailed in the technical specification. An alternate solution proposal has been submitted to SPT, ongoing dialogue with SPT on the way forward.

Achievement over the last 6 months:
32. N-3 Intertripping technical solution release for Scottish and Southern Electricity Networks (SSEN) and National Grid Electricity Distribution (NGED) commissioning of ICCP data links with ESO providing the enabling functionality for ENCC to curtail the generation if needed.
33. MW Dispatch RDP1 NGED technical solution release providing the enabling functionality for the permitting DER’s to continue to connect in congested areas by providing NGESO market access to DER.</td></tr>
<tr><td rowspan="4">Spend</td><td colspan="6">FY24 & FY25 Period</td></tr>
<tr><td>BP2 Submission</td><td>£7.7m</td><td>BP2 submission with BP1 under/overspend</td><td>£9.3m</td><td>Approved Spend</td><td>£7.0m</td></tr>
<tr><td colspan="6">FY22 to FY26 Period</td></tr>
<tr><td>BP2 Submission</td><td colspan="2">£17.1m</td><td>Approved Spend</td><td colspan="2">£13.1m</td></tr>
</table>

350 Planning and outage data exchange	
Delivery update	We made a decision to implement quarterly releases moving from one release in FY24, for our eNAMS workflow and user interface enhancements release train to further address customer needs. A replanning exercise for Deeper DNO/DSO Access has been initiated due slow progress within the Discovery phase, to realign the plan with committed deliverables. Our work on External Data Exchange (EDE) Replacement has progressed steadily alongside the external progress of GC0139 with ongoing work to finalise requirements.

	Achievements over last 6 months: 34. Implemented two releases driving value to the industry across network outage planning, constraint management and external reporting processes. 35. GC0139 impact analysis of grid code change baselined					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£3.3m	**BP2 submission with BP1 under/overspend**	£3.2m	**Approved Spend**	£2.9m
	FY22 to FY26 Period					
	BP2 Submission	£8.4m		**Approved Spend**	£8.1m	

360 Offline network modelling						
Delivery update	We reached and implemented an agreement with National Grid Electricity Transmission (NGET) to create a separate NGET instance of OLTA on the ESO platform. This mitigated a risk to the capacity of OLTA's database and enables further preparation for full separation of NGET out of OLTA later this year. We also decided to bring forward our major refresh from Q3 FY25 to Q1 FY25, to enable delivery of enhanced High Voltage Direct Current (HVDC) modelling capability for offshore connections earlier than previously planned. We also mobilised our Electro-Magnetic Transience (EMT) modelling project delivery team and progressed requirements and learning from parallel Network Innovation Allowance (NIA) projects. **Achievements over last 6 months:** 36. Upgraded to Powerfactory 2022 in OLTA and delivered enhanced G74 modelling capability within OLTA models 37. Implemented Premium Storage on OLTA Platform which improved performance by 30% 38. Incremental security enhancement to OLTA Platform 39. Commenced POC build for Enhanced Azure NETAPP file storage 40. Go Live of NGET OLTA database instance and further preparation for NGET full separation out of OLTA					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£3.5m	**BP2 submission with BP1 under/overspend**	£4.9m	**Approved Spend**	£5.4m
	FY22 to FY26 Period					
	BP2 Submission	£8.1m		**Approved Spend**	£8.6m	
	Underspend from BP1 has been deferred to BP2, this is due to the OLTA Hardware refresh changing into an Azure migration & adoption project, taking longer to complete. Major release of PowerFactory has been brought forward into FY24. Next Major release will be put into FY26.					

380 Connections platform						
Delivery update	A new multi-year roadmap was required to better suit business requirements post Minimal Viable Product (MVP) release. Roadmap developed with customers for FY24-FY26, reprioritising features in line with business needs. **Achievements over last 6 months:** 41. The Connection Portal is now live, with 550 active customers since its release March and with over 120 customers registering through the Connections portal in May. 42. We also released Application Fee Calculator which allows our customers to see their application fee before submitting their request. 43. Rolled out Application Fee Reconciliation which triggers increased automation for the time sheeting process and increased transparency on the app fee reconciliation status.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£3.0m	**BP2 submission with BP1 under/overspend**	£3.2m	**Approved Spend**	£3.7m
	FY22 to FY26 Period					
	BP2 Submission	£7.0m		**Approved Spend**	£7.5m	
	Additional development resources required to deliver updated roadmap following initial MVP.					

390 NOA enhancements						
Delivery update	**Achievements over last 6 months:** 44. The Economic Assessment Tool is now live for the EMR process delivering improved results. 45. Probabilistic Modelling (POUYA) - Early life support complete for core release and Web UI Enhancement in progress. 46. Economic Assessment Tool (PLEXOS) – Redispatch model delivered by EE, Business validation in progress. Scoping commenced for enhancements (nodal modelling and ancillary services). 47. Voltage Optimisation development commenced, focusing on the Electricity Ten Year Statement (ETYS) processes. 48. Stability Assessment requirements gathering complete.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£6.0m	**BP2 submission with BP1 under/overspend**	£6.3m	**Approved Spend**	£6.0m
	FY22 to FY26 Period					
	BP2 Submission	£9.3m		**Approved Spend**	£8.8m	

500 Enhanced Frequency Control						
Delivery update	NIA contracts signed between GE and ESO and we are now planning delivery activities with vendor.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£0.2m	**BP2 submission with BP1 under/overspend**	£0.3m	**Approved Spend**	£0.2m
	FY22 to FY26 Period					
	BP2 Submission	£1.2m		**Approved Spend**	£1.3m	

640 Network Planning Review						
Delivery update	We are progressing with early stages of discovery work, engaging with various stakeholders.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£0m	**BP2 submission with BP1 under/overspend**	£0m	**Approved Spend**	£0m
	FY22 to FY26 Period					
	BP2 Submission	£0m		**Approved Spend**	£0m	

650 Accelerating Whole Electricity Flexibility						
Delivery update	A decision was made to withhold the Primacy Technology Discovery stage start in Q2 FY24 and instead to continue with pre-project support to the Primacy team. This decision was driven by the continued evolution within the internal and external business impacts from Primacy, of the ongoing Ofgem consultations. Once there is less ambiguity on scope, we will mobilise the discovery work.					
Spend	**FY24 & FY25 Period**					
	BP2 Submission	£0.1m	**BP2 submission with BP1 under/overspend**	£0m	**Approved Spend**	£0.1m
	FY22 to FY26 Period					
	BP2 Submission	£0.1m		**Approved Spend**	£0.1m	