nationalgridESO

ESO RIIO2 Business Plan 1 (2021-23)

2021-23 18-Month Review

25 October 2022

Contents

RIIO-2 Reporting

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

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

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

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

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

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

Please see our website for more information.

Introduction

For the BP1 18-month incentives review process we have agreed with Ofgem an alternative approach to that which is set out in the ESORI Guidance Document. This alternative approach is more streamlined with a view to reducing the assessment workload for Ofgem over the winter period, and also to trial a new incentives process that could potentially be used in the future.

This new approach means that this report does not include all of the elements that would typically be included in the 6-monthly review process. This report includes all elements that form part of the usual quarterly reports (metrics performance and plan delivery) plus other elements including stakeholder survey results and value for money updates. This report does not include an executive summary, further stakeholder insight or cost benefit analysis.

Ofgem and the Performance Panel will not be publishing detailed feedback reports and there will be no scoring or financial projections provided as part of this 18-month review. Instead, feedback will be provided via deep dive discussions with Ofgem and the Performance Panel. These deep dive sessions will take place between November and March and will focus on specific performance areas across the three roles with targeted feedback provided afterwards.

There are no planned changes to the end of scheme reporting process and this will follow the process as set out in the ESORI Guidance Document.

Winter preparedness

Context

As a consequence of the continued Russian invasion of Ukraine, there are ongoing concerns that gas supplies from Russia to Europe are likely to be disrupted over the Winter 2022/23 period. In May, the BEIS Secretary of State wrote to the ESO requesting that we engage with industry to explore ways to enhance security of supply in light of this increased risk.

As a result, the ESO have developed a programme of activities and actions for this winter to minimise the potential impacts on electricity customers in Great Britain. We are also in the midst of an energy price crisis and must do everything we can to manage overall costs to consumers, while ensuring safe, reliable electricity supply. These new winter activities do not form part of the RIIO-2 Business Plan for the current BP1 period, and therefore do not have associated milestones within the BP1 deliverables tracker.

To accommodate these unplanned and urgent winter activities, we have, and will be, using a prioritisation approach based on benefits, external/internal dependencies, alignment with delivery priorities, and the capability we need to deliver the requirement. Keeping the lights on and safety will always be our top priorities, therefore certain activities have and will be deprioritised as a result. Any delays that have already taken place will be captured in the latest update to the deliverables tracker through status changes and associated commentary.

Despite the significant work surrounding the winter activities as shown in the below section, we have continued to deliver important and critical BP1 milestones in the last quarter. These include, amongst many more, continued functional updates to the Balancing Mechanism, the hugely successful 2022 Future Energy Scenarios (FES) launch, the Pathway to 2030 Holistic Network Design publication, and many large stakeholder engagement events including the Autumn Markets Forum. Along with these, we also published our final RIIO-2 Business Plan 2 (BP2) submission which involved a significant amount of work and collaboration across ESO. The “Deprioritised BP1 Deliverables” section below shows the few BP1 deliverables that been impacted as a direct result of the incremental winter activity work and these delays have been minimised as much as possible.

We will be conducting a deep dive session with Ofgem and the Performance Panel to provide more insight into the prioritisation process for the winter activities before the end of the year.

Winter Activities

See below an overview of some of the key winter activities underway and the roles that are impacted. Across all activities we have also been engaging heavily with both BEIS and Ofgem.

Activity: **Demand Flexibility Service**	Roles Impacted: **All**
The Demand Flexibility Service (DFS) has been rapidly developed, as a key tool, in helping preserve security of supply for winter. This will be the first time ever that the true value of Demand Flexibility has been realised, as a critical operational service. The introduction of this innovative product will allow us to access additional flexibility when the national demand is at its highest during peak winter days. This service will allow consumers, as well as industrial and commercial users (through suppliers/aggregators), to be incentivised for voluntarily time-shifting their usage of electricity in return for a fee. Working collaboratively with industry we have designed a product, that will access previously inaccessible areas of flexibility and build on trials that had been previously shown the potential of consumer flexibility. While compromises have been made to deliver the product in time to make a difference for this Winter, the introduction of this will act as a major catalyst to unlock the enduring value of flexibility, and the potential for reducing future balancing costs and support the transition to net zero.	

Activity: **Winter Contingency Contracts**	Roles Impacted: **1 & 2**

At the request of the Secretary of State, we had the challenging task of negotiating with three separate organisations to extend the life of coal fired power plants for this Winter.

Multiple factors and challenging interplays had to be overcome to deliver these critical contracts that simultaneously supported resilience and security of supply, while promoting the integrity of existing power markets and delivering consumer value.

Following lengthy negotiations, which looked to achieve a broadly standardised approach across the three commercial organisations - contracts were struck with a combined value of £400m creating the insurance policy for the GB consumer for this Winter. This was made possible through working collaboratively with Government, Regulators and Generators, to achieve the varying outcomes that were important to each party. Furthermore, we have provided as much transparency as possible to the broader industry, so that the construct and use of these contracts is fully understand so as to minimise any market perversities.

Activity: **Interconnector Operations**	Roles Impacted: **1 & 2**

We have developed a set of principles of how ESO will operate interconnectors in various winter scenarios. This has involved engagement with European TSOs and interconnector owners and operators.

Activity: **Crisis Communications & Exercises**	Roles Impacted: **1**

The ESO crisis management protocols have been reviewed and briefed to ensure that all internal parties are aware of the roles and responsibilities that they will need to fulfil in the event of an incident/crisis. We have completed an ESEC (Electricity Supply Emergency Code) workshop and exercise to support and train BEIS. We have more exercises planned to help us prepare for different scenarios that could occur this winter.

Activity: **TO Engagement on Winter Resilience**	Roles Impacted: **1**

We have implemented a winter resilience forum with each TO to review and optimise their winter outage plans whilst identifying key risks to system capacity over the winter. In some cases new outage dates have been agreed in the Spring, and in other cases new ways of working have been agreed to reduce Emergency Return to Service Times (ERTS) for outages that would be likely impact on system margin over the winter. This increased engagement is planned to continue throughout the winter to ensure risks to system capacity are mitigated whilst continuing to allow access to the system for essential maintenance and system reinforcement.

Activity: **Industry Financial Support**	Roles Impacted: **2**

To help provide support against the wider cost of living crises, we have facilitated delivering £250m worth of financial relief for Generators and Suppliers. In order to manage the cost challenges of this Winter and to facilitate the wider interventions required to manage Winter System operability, we have led and participated in multiple code changes. Through CMP395 a cap on BSUoS costs has been put in place, capping these at £40/MWh. This has been made possible through the creative utilisation of the ESO balance sheet and working capital facilities.

Not only have we provided financial support, but we facilitated the process of the Emergency Mod being raised and adapted our usual processes to give effect to this change – making sure that the benefits flowed through to the end consumer.

Activity: **Codes Winter Activities**	Roles Impacted: **2**
We have carried out consultations and changes to our C16 statements that define the procurement and management of our balancing services alongside an urgent BSC modification proposal (P447). Taken together, these have enabled our new DFS service and allowed for the correct treatment of the winter coal contingency contracts through industry cash-out mechanisms. Finally, we have supported industry and government in other areas, such as proposing changes to the BSC (P446) to allow Elexon to carry out the administrative function for the domestic price cap scheme. We have also supported generators to develop a further modification (P448) to ensure gas generators are not fully exposed to cashout prices in event of a gas deficit emergency.	

Activity: **Winter Outlook**	Roles Impacted: **2**
Heading into a usual Winter we publish a single Winter outlook in October. Given the level of uncertainty and geopolitical risk associated with this Winter, we provided an Early View of our Winter Outlook in July – highlighting some of the risks and the mitigating factors that we were working on. The delivery of the full Winter Outlook in October required far greater volumes of modelling, coordination, and alignment with key stakeholders to provide the right level of detail to help support multiple stakeholders prepare for the Winter ahead.	

Deprioritised BP1 Deliverables

The following BP1 deliverables have been delayed as at the end of the September 2022 as a result of prioritisation decisions related to the winter preparedness activities. In our Role 2 Market Change Delivery function 7 FTE have been reallocated for the winter activities.

- D4.3.2: Phase out of monthly tenders for Firm Frequency Response (Role 2)
- D4.3.3: Control and dispatch solutions for reserve (Role 2)
- D4.6.2: Initiate delivery of enduring plan for reactive reform as required (Role 2)
-
- D4.2.2: Power Responsive (Role 2)
- D16.2.1: Enhance the Network Access Policy (NAP) process with TOs (Role 3)

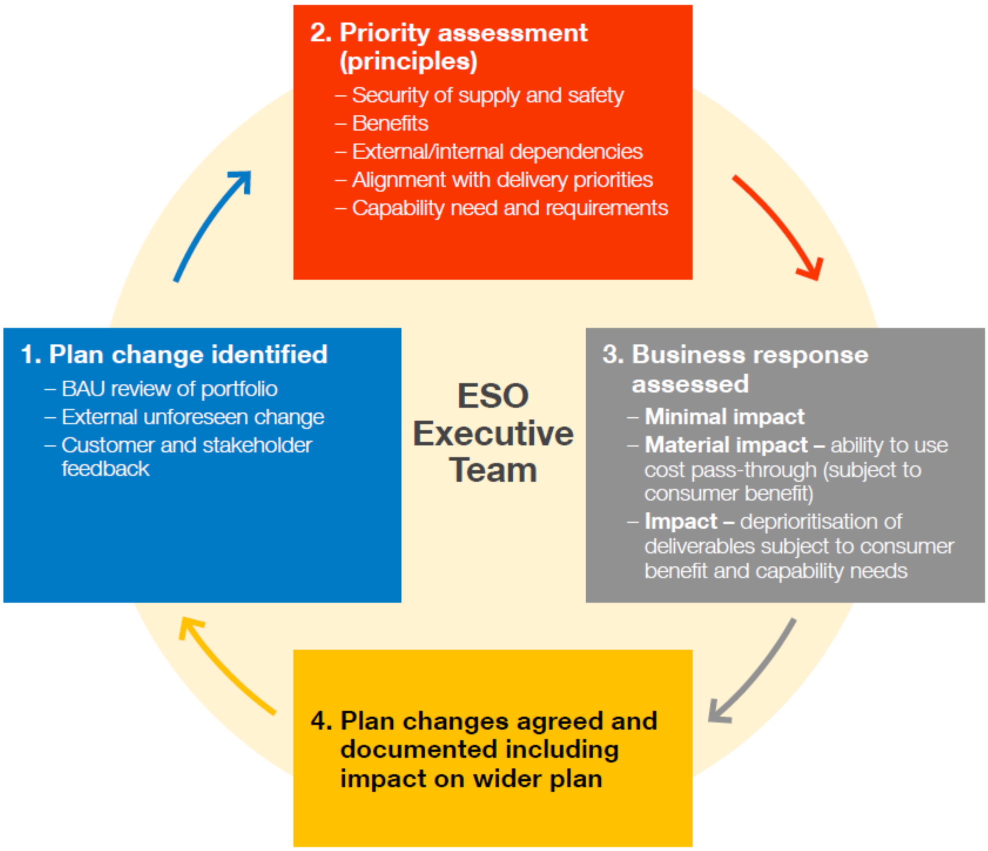
For further information on each activity please refer to the latest deliverables tracker.

It is possible through the continuation of the winter activities work, and with the potential for additional issues to arise over the period, there may be further impacts to BP1 activities with subsequent prioritisation decisions made. Any decision will go through the prioritisation framework (see below).

Prioritisation Approach and Principles

Throughout BP1 we have continuously prioritised our efforts, however stakeholders have told us that they would like more transparency around our prioritisation process and how we adapt our plans over time.

We have developed a prioritisation approach based on a set of principles as shown in the diagram below. This approach has been adopted for the winter activities as described in this section. We look forward to providing greater transparency of our decisions going forward.



Summary of Notable Events

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

- We published our final RIIO-2 Business Plan 2 (BP2) submission, ‘Accelerating the transition to a flexible, low carbon energy system’ (on 31 August). BP2 sets out our goals for years three and four of RIIO-2 (2023-2025) as we respond to the rapidly changing external environment.
- We published ‘Regional Insights from FES 2022’, a brand-new document summarising the key insights from a regional perspective from this year’s FES publication.
- We hosted our Autumn Markets Event on 28 September, which gave us the opportunity to engage in conversations with a range of stakeholders on our Markets priorities.
- We deployed the latest set of functional updates to the Balancing Mechanism systems in the control room in September.
- We launched a new initiative to connect electricity generation to the transmission system faster.
- The tender assessment for the Stability Phase 3 Pathfinder has now concluded and on 27 September all bidders were informed of their individual outcomes.
- We raised an urgent BSC modification (P447) and an urgent C16 change consultation to protect the industry from adverse settlement prices if the Winter Contingency Service is called upon this winter.
- We worked proactively with industry to quickly develop a set of solutions for CMP395, an urgent CUSC modification raised by industry to cap BSUoS costs and defer payment to 2023/24 in order to help support reducing the impact of the cost of living crisis.
- As part of Regional Development Programme 1 (RDP1), the roll-out of the MW Dispatch service with National Grid Electricity Distribution (NGED), both parties held a progress update webinar with Distributed Energy Resources (DER) on 27th September.

Below are some of the highlights that we successfully delivered earlier in Q2:

- In July we updated our Electricity National Control Centre (ENCC) Transparency Roadmap.
- The ESO was awarded a second grant from Ofgem’s Strategic Innovation Fund (SIF) as part of a wider project that looks to understand how domestic flexibility can be used to help manage the grid.
- We held a Power Responsive Summer Event in London on in July with over 250 attendees.
- The EMR Delivery Body & Delivery Partners hosted the annual Capacity Market Launch Event in July.
- In July we published our Winter Outlook 2022-23, our 2022 Future Energy Scenarios (FES) and our Pathway to 2030 Holistic Network Design (HND).
- In August we launched a consultation on our proposal to launch a new Winter demand flexibility service, that will utilise and reward household and business energy flexibility.
- We put in place contracts with EDF and Drax to secure up to approximately 1500 GWh of energy from four coal fired generation units that would otherwise have closed before Winter 2022/23.
- Octopus Energy published the results from the Domestic Scarcity Reserve Trial that we collaborated on in February and March this year.
- The ESO and Octopus Energy Group announced the first successful integration of vehicle-to-grid (V2G) technology, using a test environment of the Balancing Mechanism
- As part of the ESO’s Restoration and Resilience services strategy, a one-off wind specific tender was launched in August, alongside the usual region-specific tenders.
- The tender for B6 Constraint Management Pathfinder 2024–2025 was also launched in August.
- ESO and Energy Exemplar announced an agreement to use the energy market simulation platform PLEXOS to identify cost-efficient grid expansion priorities.

Metrics and RREs

The tables below summarise our Metrics and Regularly Reported Evidence (RRE) performance for April 2022 to September 2022. We then report on all Metrics and RREs by role.

Table 1: Summary of Metrics

			2021-22	2022-23						
Metric		Unit	Full Year	Apr	May	Jun	Jul	Aug	Sep	**Overall 18-Month Status**
1A	**Balancing Costs**	£m		188	214	335	385	326	275	**Below** expectations
1B	**Demand Forecasting**	%		2.9%	2.6%	2.2%	2.3%	2.2%	2.3%	**Below** expectations
1C	**Wind Generation Forecasting**	%		4.2%	4.5%	4.1%	4.4%	3.8%	5.7%	**Exceeding** expectations
1D	**Short Notice Changes to Planned Outages**	#		7	1.4	1.4	3	1.3	2.7	**Meeting** expectations
2A	**Competitive procurement**	%		Q1: 46%			Q2: 47%			**Below** expectations

Table 2: Summary of RREs

			2022-23					
RRE	Title	Unit	Apr	May	Jun	Jul	Aug	Sep
1E	Transparency of Operational Decision Making	%	92%	93%	93%	89%	89%	90%
1F	Zero Carbon Operability indicator	%	Q1: 84%			Q2: 74%		
1G	Carbon intensity of ESO actions	gCO2 /kWh	3.2	2.2	4.2	0.3	0.4	-0.4
1H	Constraints cost savings from collaboration with TOs	£m	Q1: £336m			Q2: £503m		
1I	Security of Supply	#	1	1	1	1	-	-
1J	CNI Outages - Planned	#	-	-	-	1	-	-
	CNI Outages - Unplanned	#	-	-	-	-	-	-
2B	Diversity of service providers	n/a	See report for details					
2E	Accuracy of Forecasts for Charge Setting (BSUoS)	%	106%	32%	17%	2.4%	30%	49%
3A	Future savings from Operability Solutions	£m	i) Saved balancing costs: £27m for 2021-22, £90m for 2022-23					
			ii) Saved infrastructure costs: RDP avoided asset build estimated at £12.9m as per RIIO2 Business Plan					
			iii) Monetised carbon reductions:	Pathfinders: Estimated £69m (2021-22 to 2024-25). RDPs: Estimated £41m (2021-22 to 2025-26).				
3B	Consumer Value from the NOA	£m	£212m NOA consumer benefit, £588m benefit from ad-hoc CBAs and £1,085m benefit from LOTI CBAs					
3C	Diversity of Technologies Considered in NOA	#	29 asset based solutions (including 21 new options) and 8 commercial solutions submitted to NOA 2022-23.					

Role 1 Control Centre operations

Metric 1A Balancing cost management

September 2022 Performance

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

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

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

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

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

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

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

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

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

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

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

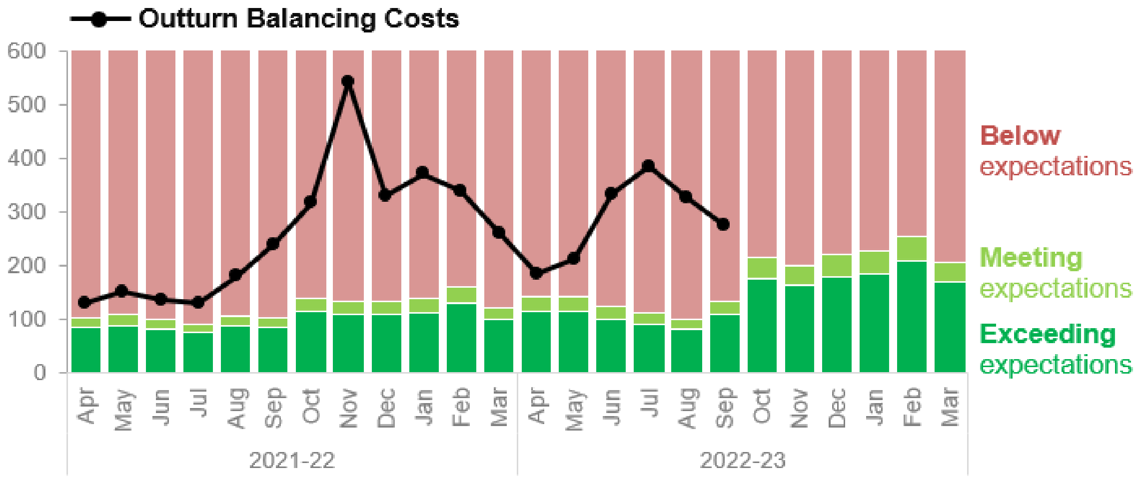


Table 3: Monthly balancing cost benchmark and outturn

All costs in £m	Apr	May	Jun	Jul	Aug	Sep	YTD
Benchmark: non-constraint costs (A)	50	50	50	50	50	50	252
Indicative benchmark: constraint costs (B)	97	89	90	81	101	107	458
Indicative benchmark: total costs (C=A+B)	147	139	140	132	152	158	710
Outturn wind (TWh)	3.8	3.8	3.1	2.8	2.3	3.5	**19.2**
Ex-post benchmark: constraint costs (D)	80	80	62	52	42	73	**389**
Ex-post benchmark (A+D)	130	130	113	130	93	123	692
Outturn balancing costs[2]	188	214	335	385	326	275	1722
Status	●	●	●	●	●	●	●

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

Performance benchmarks

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

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

Supporting information

Data issue: Please note that due to a data issue on a few days over the last few months, the **Minor Components** line in Non-Constraint Costs is capturing some costs on those days which should be attributed to the Constraints Costs lines. 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.

September performance

The Balancing costs for September 2022 were £275m, which is a decrease of £52m from August.

Both constraint and non-constraint costs fell this month, but on a year to date basis both remain higher than last year.

The non-constraint cost spend variance to September last year is due to the significantly high Operating Margin costs recorded in September 2021 due to scarcity pricing, which was reflected in the unusually high Operating Reserve costs recorded during that month. As a consequence, the Operating Reserve costs this month showed a decrease close to £100m from the same period last year.

However, due to persistent high gas prices, Response and Reactive prices remain high compared to last year despite a decrease in the volume of related actions.

The overall increase in constraint costs this year is the result of continued high wholesale prices. This in turn increases the cost of the Balancing Mechanism (BM) actions that we are required to take in order to reduce generation behind constraints and replace it with alternative generation. This is particularly the case at times of high wind and reduced boundary capability due to system outages.

Breakdown of costs vs previous month

Balancing Costs variance (£m): September 2022 vs August 2022

		(a) Aug-22	(b) Sep-22	(b) - (a) Variance	decrease ◄► increase Variance chart
Non-Constraint Costs	Energy Imbalance	-8.6	-4.7	3.9	
	Operating Reserve	52.8	47.9	(5.0)	
	STOR	10.7	9.7	(1.0)	
	Negative Reserve	-0.3	0.5	0.8	
	Fast Reserve	25.7	19.2	(6.5)	
	Response	31.1	34.4	3.3	
	Other Reserve	1.4	1.4	0.0	
	Reactive	25.0	35.7	10.7	
	Restoration	3.0	2.9	(0.1)	
	Minor Components	48.1	33.0	(15.1)	
Constraint Costs	Constraints - E&W	18.9	11.0	(7.9)	
	Constraints - Cheviot	0.2	0.6	0.4	
	Constraints - Scotland	34.7	27.7	(7.0)	
	Constraints - Ancillary	0.4	0.2	(0.2)	
	ROCOF	2.5	8.0	5.4	
	Constraints Sterilised HR	80.9	47.1	(33.8)	
Totals	Non-Constraint Costs - TOTAL	188.8	179.9	(8.9)	
	Constraint Costs - TOTAL	137.6	94.6	(43.0)	
	Total Balancing Costs	**326.4**	**274.5**	**(51.9)**	

As shown in the total rows above, both non-constraint and constraint costs fell this month, by £8.9m and £43.0m respectively.

For constraint costs, the breakdown shows that Constraint Sterilized Headroom, Constraint E&W and Constraint Scotland were the key categories behind the decrease from August, whilst all the other categories either increased or showed little variance from the previous month.

For non-constraint costs, a decrease was seen in Minor Components, Operating Reserve, STOR and Fast Reserve. Reactive, Response and Energy Imbalance increased, whilst all the other categories showed little variance.

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

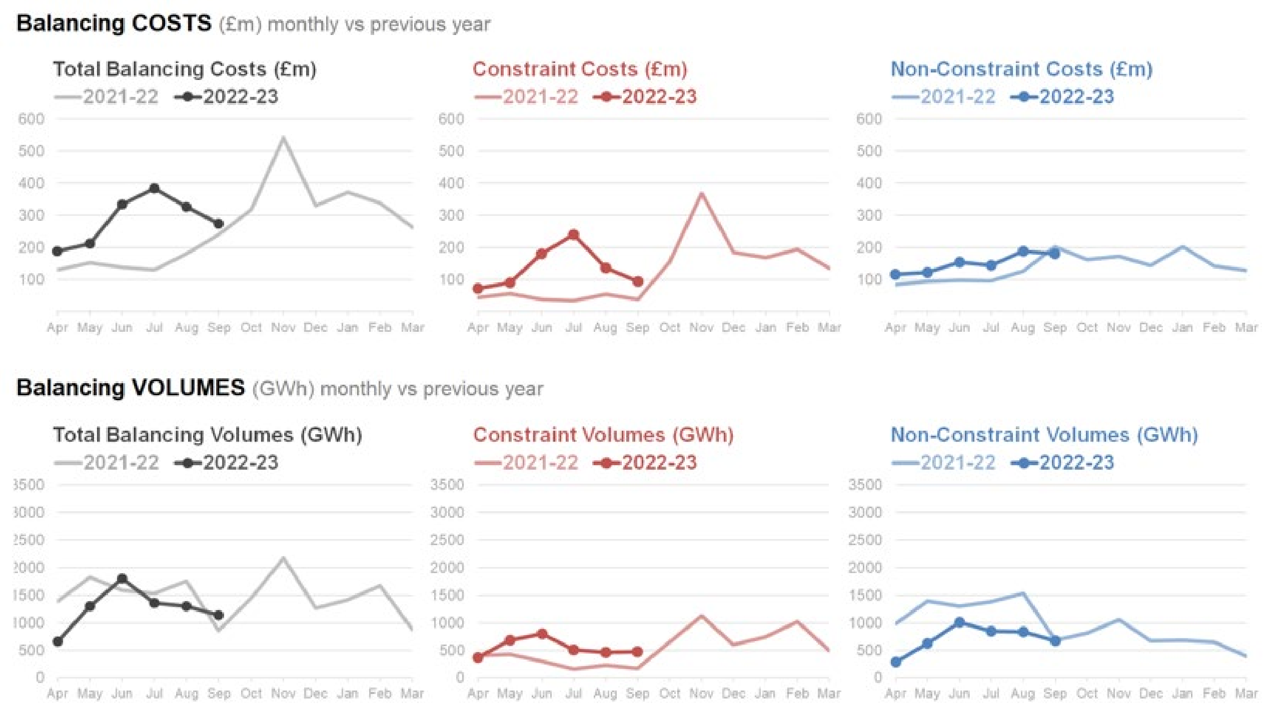
- **Constraint Sterilized Headroom (HR): £33.8m decrease.** Less generation was restricted behind constraints, leading to a fall in the spend to replace the additional energy available on constrained generators elsewhere outside the constraint.
- **Constraint - E&W: £7.9m decrease.** Fewer BM actions were required to reduce generation in order to manage thermal constraint in England and Wales.
- **Constraint - Scotland: £7.0m decrease.** Fewer BM actions were required to reduce generation in order to manage thermal constraint in Scotland.
- **RoCoF: £5.4m increase.** Lower inertia levels at times of high wind required a higher volume of BM actions to secure the system against the RoCoF risk.

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

- **Minor Components**: **£15m decrease**. As mentioned above, we know that currently some costs are being allocated incorrectly as Minor Components, and this month the figure is smaller than it was last month.
- **Reactive: £10.7m increase.** At the time of writing, we are awaiting data volumes for Reactive which will help us to understand the reason for this month’s increase in costs.
- **Operating Reserve: £5.0m decrease.** Healthier margins required less intervention to maintain reserve requirements.

Constraint costs vs non-constraint costs

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



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

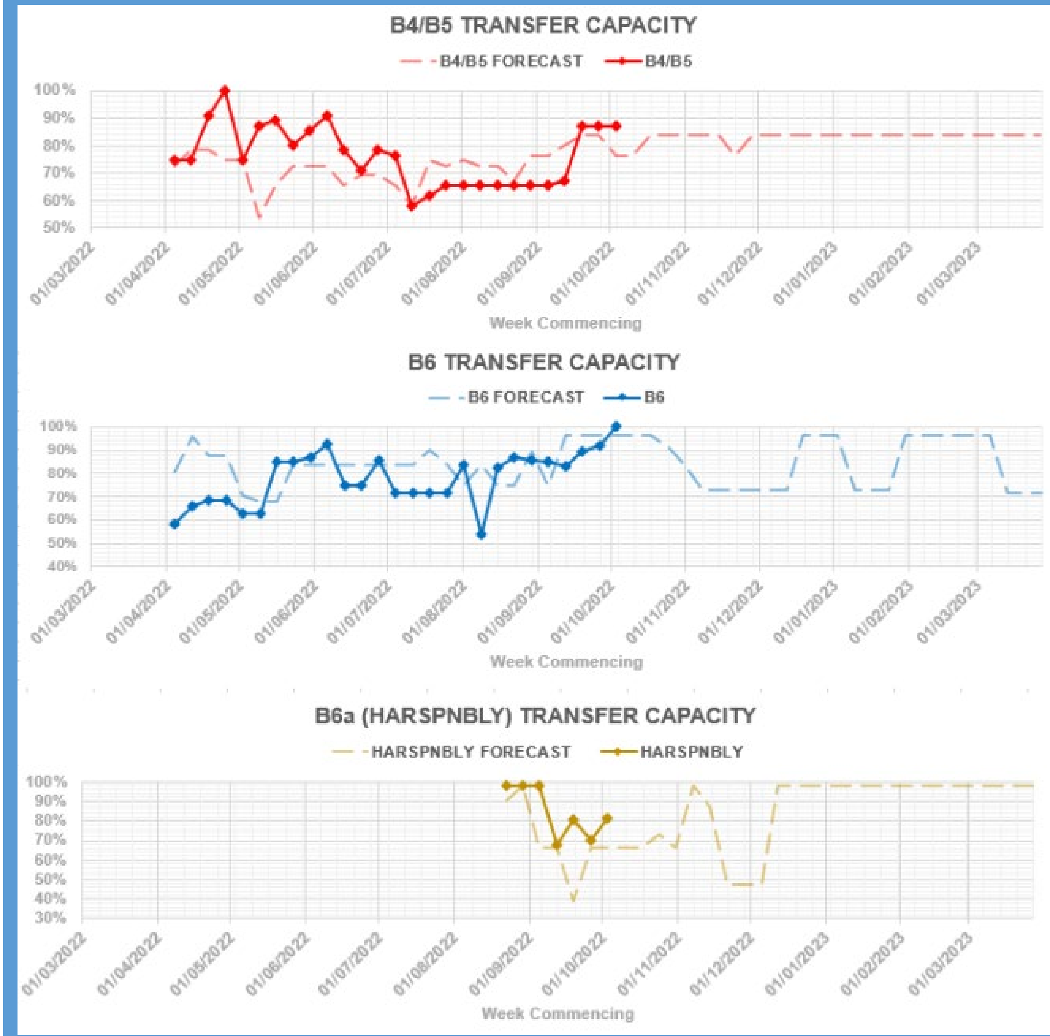
Compared with the same month of the previous year:	Constraint costs were £57m higher than in September 2021 due to: • The ongoing higher wholesale prices compared with last year. • The higher volume of actions which is in line with a higher wind generation level.
Compared with last month:	Constraint costs were £43m lower than in August 2022 due to: • An overall reduction in the wholesale prices in September 2022.

Non-constraint costs

Compared with the same month of the previous year:	Non-constraint costs were £23m lower than in September 2021: • September 2021 was impacted by exceptionally high costs due to periods of scarcity pricing. Although this September has seen higher average wholesale prices, the overall spend was lower. The volume of actions this September was also lower than the previous year. • The overall cost decrease has been lessened by an increase in Reactive cost this year, which is driven by the higher average wholesale prices.
Compared with last month:	Non-constraint costs were £9m lower than in August 2022 due to: • Lower average wholesale prices. • Some of the variation is currently unexplained due to the data issue impacting the categorisation of non-constraint costs.

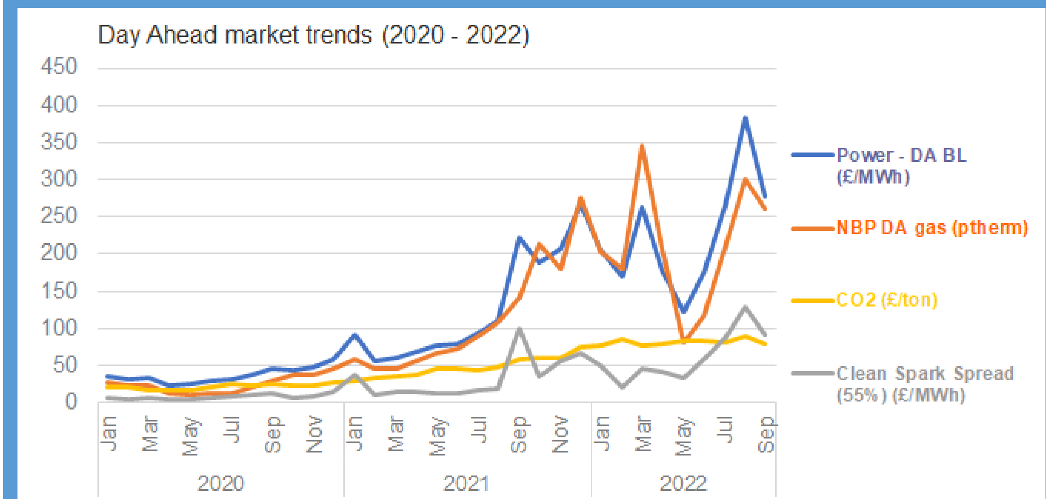
- At the time of writing, we are awaiting data volumes for Reactive which will help us to understand the reason for this month's increase in costs.

Network availability 2022-33



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

Changes in energy balancing costs

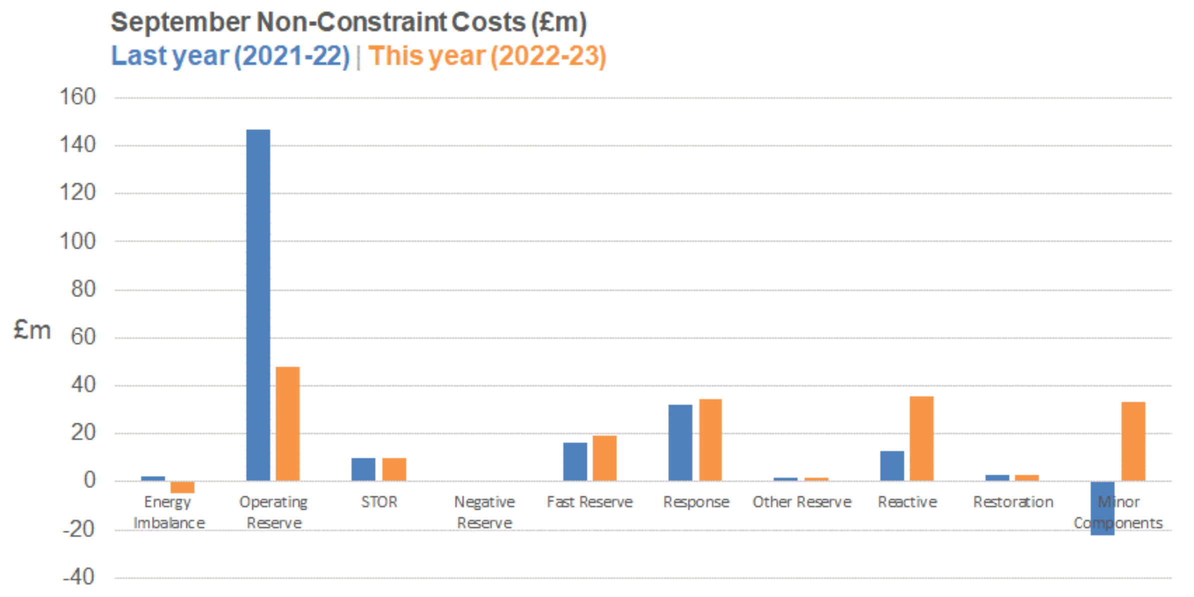


DA BL: Day Ahead Baseload **NBP DA:** National Balancing Point Day Ahead

Power day ahead prices fell in September but still remain above the level of previous years. The day-ahead gas prices have followed a similar trend. Carbon prices decreased from August but still remain higher than previous years.

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

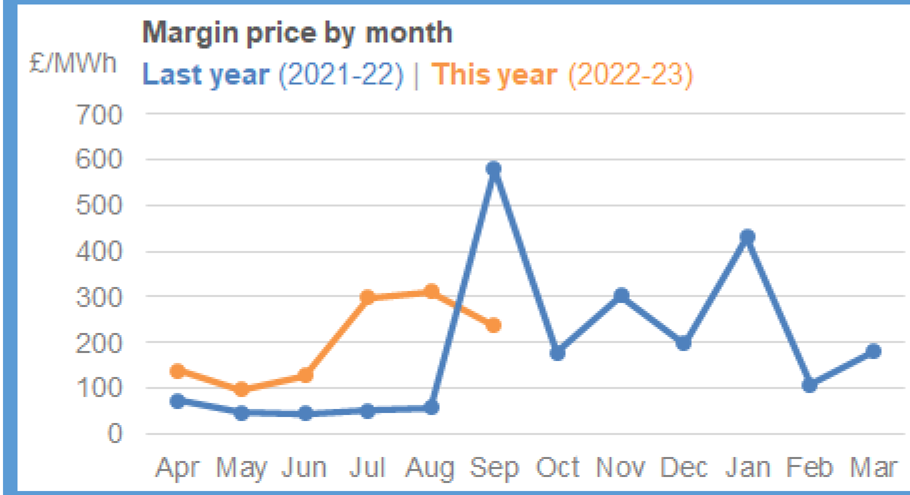
Cost trends vs seasonal norms



Comparing September 2022 non-constraint costs with those of September 2021, we can see that there has been a rise in Response, Fast Reserve, and Reactive and a much lower Operating Reserve Spend. The categories STOR, Restoration and Negative Reserve showed little variance. We do not cover the variation in Minor Components here as it is driven by the data issue referenced earlier.

- **Response** costs are £2.3m higher. With the introduction of the Dynamic Containment service as part of the changes made to manage inertia, spend continues to be higher than the previous year. The changes here have enabled a risk-based approach to managing RoCoF, resulting in lower constraint costs.
- **Reactive** costs are £23m higher. As the volume of actions taken is in line with seasonal norms, the increase in spend is driven by the increased cost of the actions taken and is therefore related to the continued high wholesale market prices.
- **Operating Reserve** costs are £99m lower. In September 2021, the spend for this category was exceptionally high due to scarcity pricing.

Drivers for unexpected cost increases/decreases



Margin prices (the amount paid for a single MWh) have decreased since August and are lower than they were in September last year.

Daily costs trends

Saturday 3 September and Sunday 4 September were the most expensive days in the month, with a daily spend that was close to £20m on both cases. Periods of windy weather requiring a large volume of BM actions to reduce generation to manage thermal constraints were the main driver behind these expensive days.

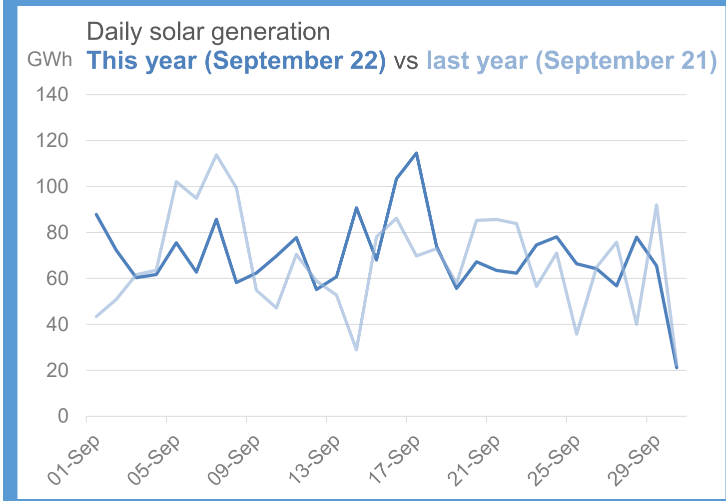
Monday 19 September was the Bank Holiday for the State Funeral of Queen Elizabeth II, and the daily outturn was around £15m. The main driver behind the high cost day was the large volume of actions required to manage the demand uncertainty.

Another expensive day was Monday 26 September, with a spend of around £16m. The high costs were driven by high wind levels requiring a large volume of BM actions to reduce generation to manage thermal constraints.

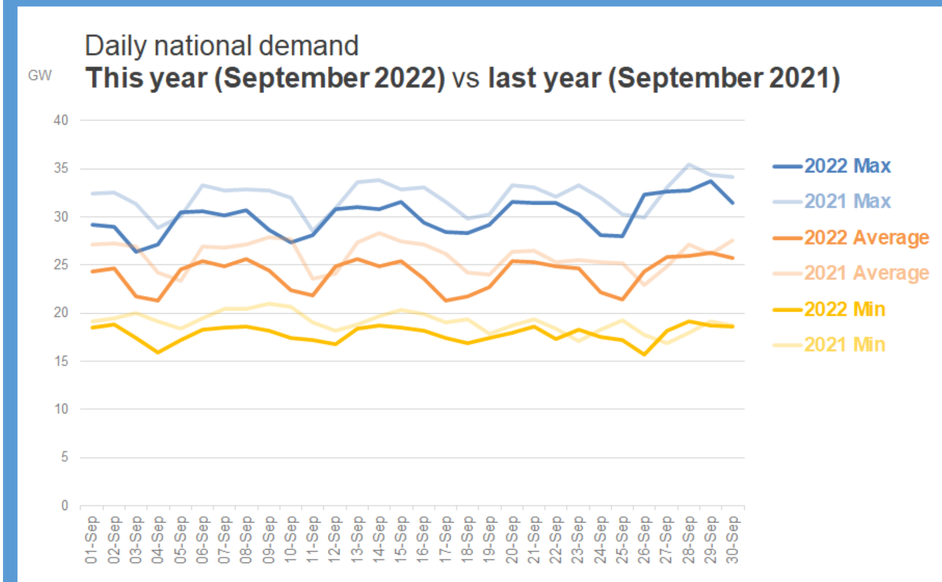
When a bid is taken to resolve a constraint, the energy on the system must then be replaced. When a large volume of BM bids is required to manage the flow on a boundary to below the constraint limit, that volume of energy needs to be procured in the BM to rebalance. The cost of the replacement energy is significantly higher than in previous years due to the ongoing high wholesale market prices.

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

Solar generation - September 2022 vs September 2021



Outturn Demand – September 2022 vs September 2021-21



Metric 1B Demand forecasting accuracy

September 2022 Performance

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

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

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

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

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

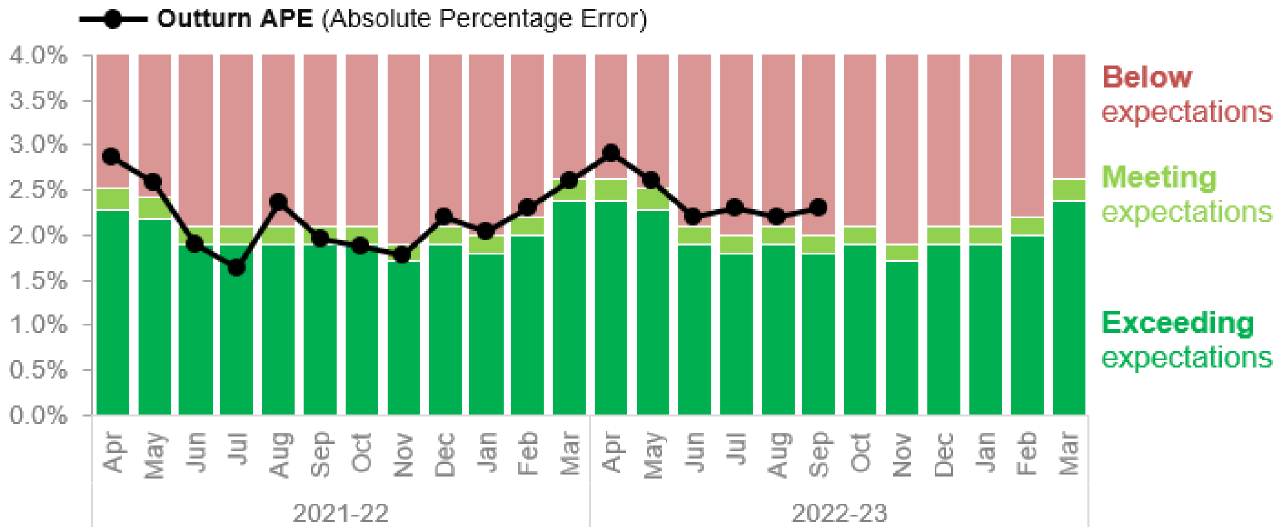


Table 4: Monthly APE (Absolute Percentage Error) vs Indicative Benchmark (2022-23)

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

Performance benchmarks

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

Supporting information

For September 2022, the mean absolute percentage error (MAPE) of our day ahead demand forecast was 2.3% compared to the indicative performance target of 1.9%, and therefore below expectations.

The biggest challenges in September 2022 were weather related. Solar generation was a contributor to these errors, and strong winds caused by weather systems to the northwest of the UK in the later part of the month caused much larger variability in both metered and distributed wind generation. There was also the major event of the State Funeral of Queen Elizabeth II affecting the whole country on 19 September.

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

Error greater than	Number of SPs	% of the SPs in the month (1440)
1000 MW	242	17%
1500 MW	88	6%
2000 MW	18	1%
2500 MW	3	0%

New data feeds to be used from November

From November, we will be increasing the amount of weather data we receive and feed into our models. This will enable model improvements to be developed over the winter period. Given the normal day-to-day variability in forecast error, it will take time to collect enough data to measure the impact of these forecast improvements robustly (at least one full quarter), so accuracy improvements won't be seen immediately.

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

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

Metric 1C Wind forecasting accuracy

September 2022 Performance

This metric measures the average absolute percentage error (APE) between day-ahead forecast and outturn wind generation for each half hour period as a percentage of capacity for BM wind units only. The benchmarks are drawn from analysis of historical errors for the five years preceding the performance year.

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

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

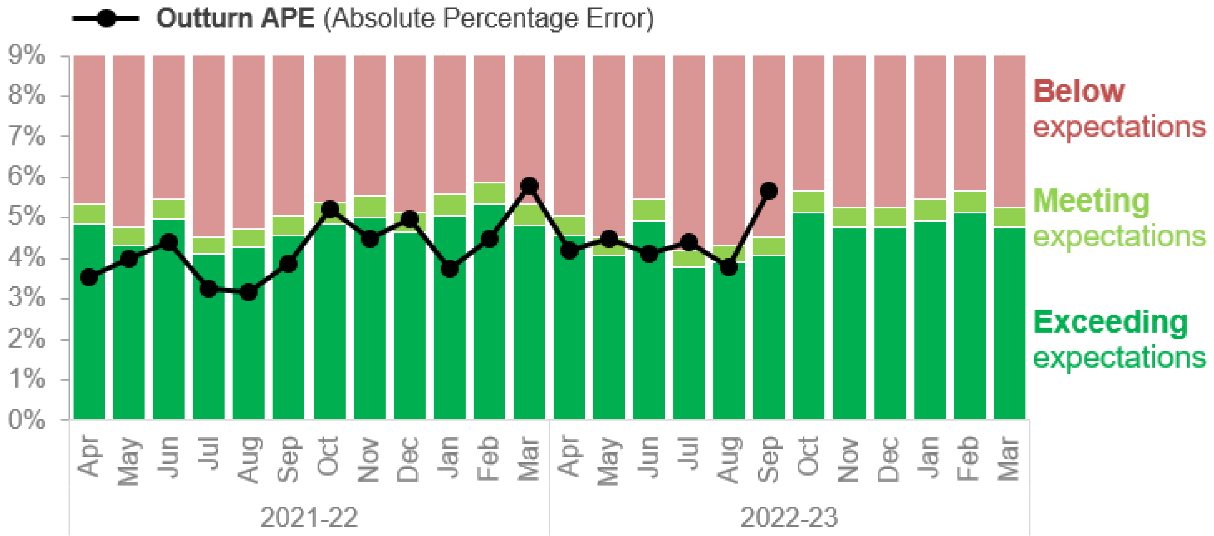


Table 5: BMU Wind Generation Forecast APE vs Indicative Benchmarks (2022-23)

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

Performance benchmarks

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

Supporting information

For September the wind power forecast accuracy achieved was 5.7% against a benchmark of 4.3% and therefore below expectations.

September is normally the month when the season begins to turn and we transition into Autumn, and the month when we break the maximum achieved wind power output. After the calm Summer, when construction of wind farms has taken place, it is in September when the first storm of the Autumn arrives and newly constructed wind turbines reach their maximum output for the first time. For this reason, September is often a month of forecast error where the capacity of under construction wind farms needs to be updated in our databases frequently so that accuracy is maintained.

Notable weather events in September were as follows.

- 7-8th: low pressure was transitioning across the republic of Ireland with a short wave trough across Eastern Scotland and East Anglia and another across South East England.
- 12-14th: a slow moving frontal system with a convergence zone passed across Southern England.
- 22-23rd: a clearly defined frontal system with wave depressions passed over the UK.
- 25-26th: a cold front progressed southwards across the UK.
- 30th: a clearly defined weather system progressed across the UK.

Lightning is a good indication of atmospheric stability, which can be an indication of wind power forecast error. Lightning was a feature of September on the following days:

- 1 September on the South Coast
- 3 September in Leeds and East Anglia
- 5-8 September widespread across the whole of GB
- 9 September widespread strikes over England..

Wind farms with CFD contractual arrangements switch off for commercial reasons while prices are negative for six hours or more. In September there were no occasions when the electricity price was negative. The electricity price used for this analysis is the Intermittent Market Reference Price. Market Price Data for August can be downloaded from here:

https://www.emrsettlement.co.uk/settlement-data/settlement-data-roles/

There were no instances of missed or late publication of forecast data.

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

Metric 1D Short Notice Changes to Planned Outages

September 2022 Performance

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

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

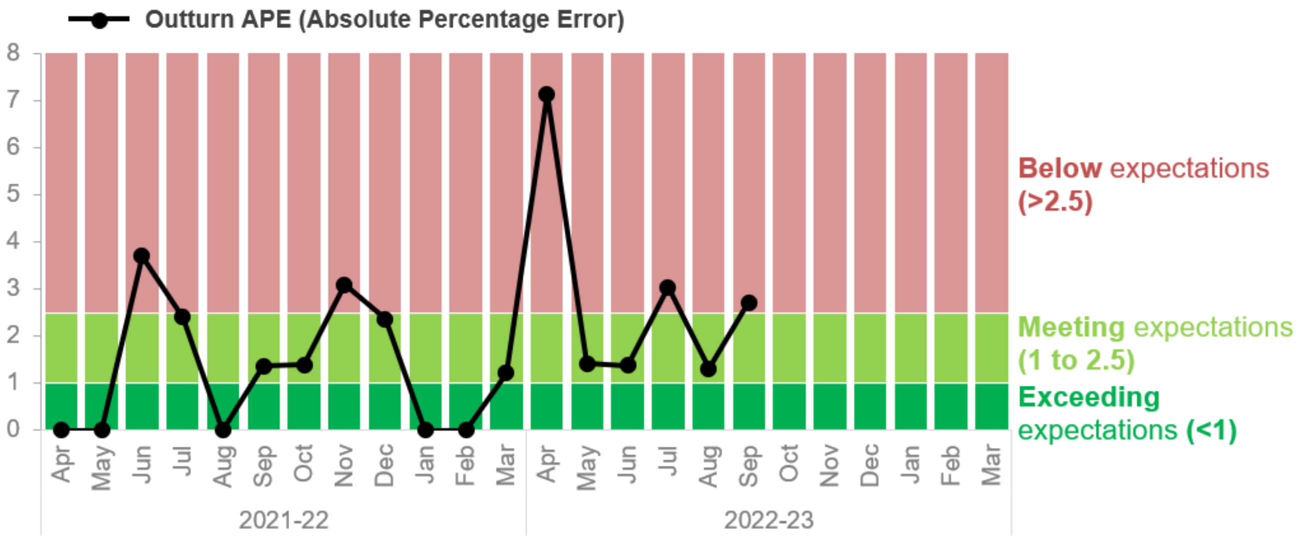


Table 6: Number of outages delayed by > 1 hour, or cancelled, per 1000 outages

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar	YTD
Number of outages	700	709	730	660	766	739							4304
Outages delayed/cancelled	5	1	1	2	1	2							12
Number of outages delayed or cancelled per 1000 outages	7.1	1.4	1.4	3.0	1.3	2.7							2.8
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, the ESO has successfully released 739 outages and there has been two delays due to an ESO process failure. The number of stoppages or delays per 1000 outages is 2.7, which is below the benchmark range of 1-2.5 per 1000 outages and therefore ‘below expectations’.

For Q2 as a whole, we released 2,165 outages and there was a total of 5 outages either delayed or cancelled due to an ESO process failure. This comes to 2.3 per 1000 outages and is therefore ‘meeting expectations’.

The two delays in September are summarised below:

1. A delay occurred on an outage where it was believed by National Grid ESO control room that the short-circuit levels at a 132kV substation were between 95% and 98%, which is within the upper limit of maximum allowable fault levels on transmission assets. This high value was identified in planning timescales but was not directly included on the operational notes handed over to the control room, and it was not clear the Distribution Network Owner (DNO) was aware of this . As a pre-caution, the outage was delayed in order to verify the short-circuit level and confirm agreement from the DNO. An operational learning note has been written that has identified corrective measures of: discussing fault levels greater than 95% with the control room in advance of the outage and including guidance within the operational notes. Furthermore, highlighting the requirement for DNO agreement if impacted by the above has been shared.

2. The second delay occurred due to a substation bar outage that required several circuits to be disconnected in line with their connection agreements which impacted multiple third party customers. Within short notice the request was made to change the dates as a third party was not being agreeable due to demand security. As a result, the planning process was followed to re-plan the outage but there was confusion around customer acceptance, where two out of three sites owned by the same customer had agreed but no response was received on the last one. It was assumed that all sites were agreeable and there was an admin issue from the customer. However, upon the control room starting the outage the following day, the customer had already committed to providing ancillary services and could not disconnect until the afternoon, resulting in a delay. An operational learning note has been written that has modified the customer notification tool for these sites, and highlighted the requirement to query customers if acceptance is not clear to eliminate any assumptions on agreement.

RRE 1E Transparency of operational decision making

September 2022 Performance

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

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

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

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

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

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

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

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

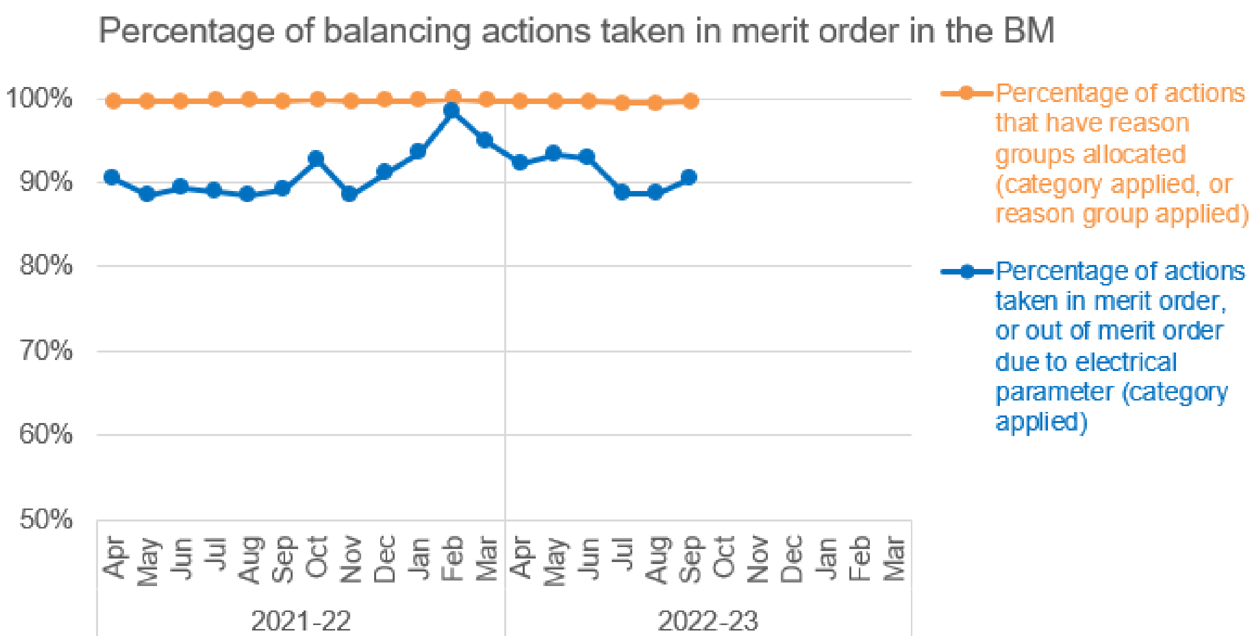


Table 7: Percentage of balancing actions taken outside of merit order in the BM

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Percentage of actions taken in merit order, or out of merit order due to electrical parameter (category applied)	92.3%	93.3%	92.8%	88.6%	88.7%	90.4%						
Percentage of actions that have reason groups allocated (category applied, or reason group applied)	99.7%	99.7%	99.6%	99.4%	99.4%	99.6%						
Percentage of actions with no category applied or reason group identified	0.3%	0.3%	0.4%	0.6%	0.6%	0.4%						

Supporting information

This month 90.4% 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 2022, we sent 42,513 BOAs (Bid Offer Acceptances) and of these, only 166 remain with no category or reason group identified, which is 0.4% of the total.

RRE 1F Zero Carbon Operability Indicator

Q2 2022-23 Performance

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

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

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

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

Part 1 – Defining the maximum ZCO limit for BP1

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

Table 8: Forecast maximum ZCO% after our operational actions

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

Part 2 – Regular reporting on actual ZCO

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

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

For each month, the settlement period that has the highest ZCO figure after our operational actions were enacted is displayed. The corresponding market ZCO figure is also included. It is worth noting that this market ZCO figure might not necessarily be the maximum ZCO that the market provided over the month. For example, the maximum ZCO provided by the market in August 2021 was 95% on 14 August, settlement period 11. However, for that period the final ZCO dropped to 68% after our operational actions were taken into account, meaning that this was not the highest final ZCO of the month.

Figures 5 and 6 further below shows the underlying data by settlement period and highlights when the maximum monthly values occurred.

Table 9: April to September maximum zero carbon generation percentage by month

Month	Highest ZCO% in the month (after ESO operational actions)	ZCO% provided by the market (during the same day and settlement period)	Date / Settlement Period
April	83.7%	92.3%	23 Apr / 28
May	78.5%	89.7%	27 May / 8
June	76.7%	72.5%	25 Jun / 9
July	73.9%	78.5%	24 Jul / 22
August	67.3%	75.3%	03 Aug / 7
September	73.5%	74.3%	17 Sep / 30

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

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

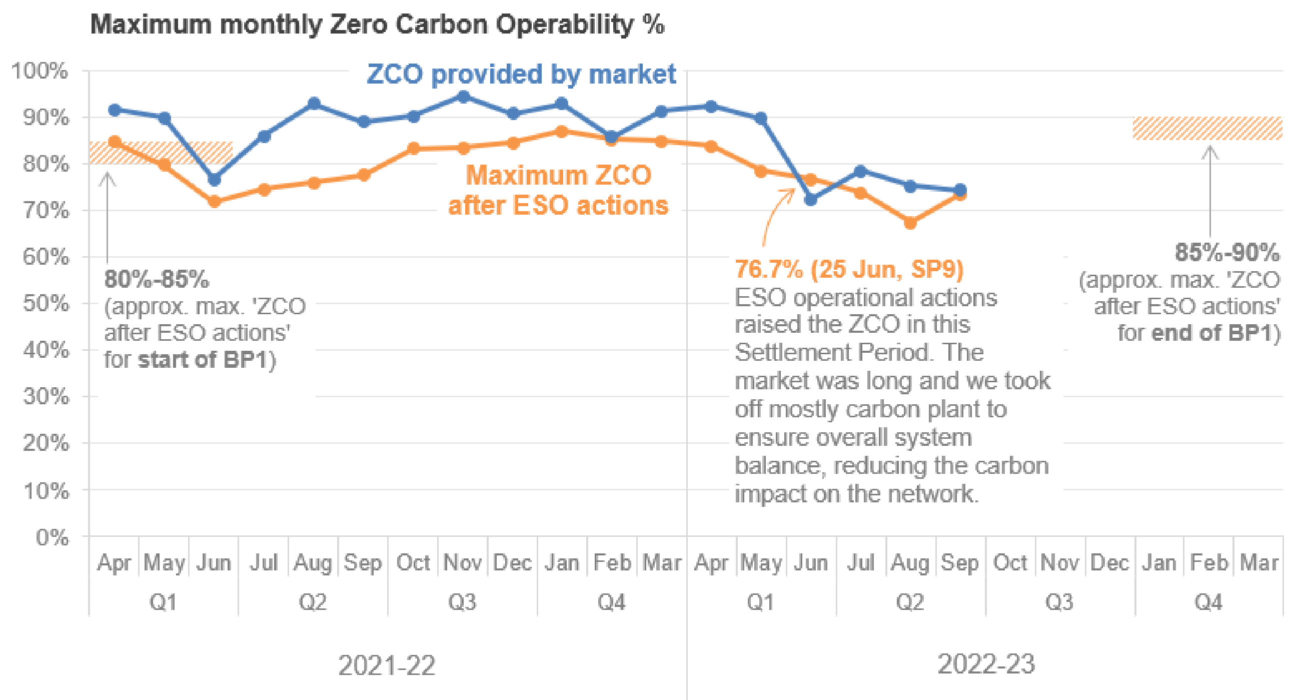
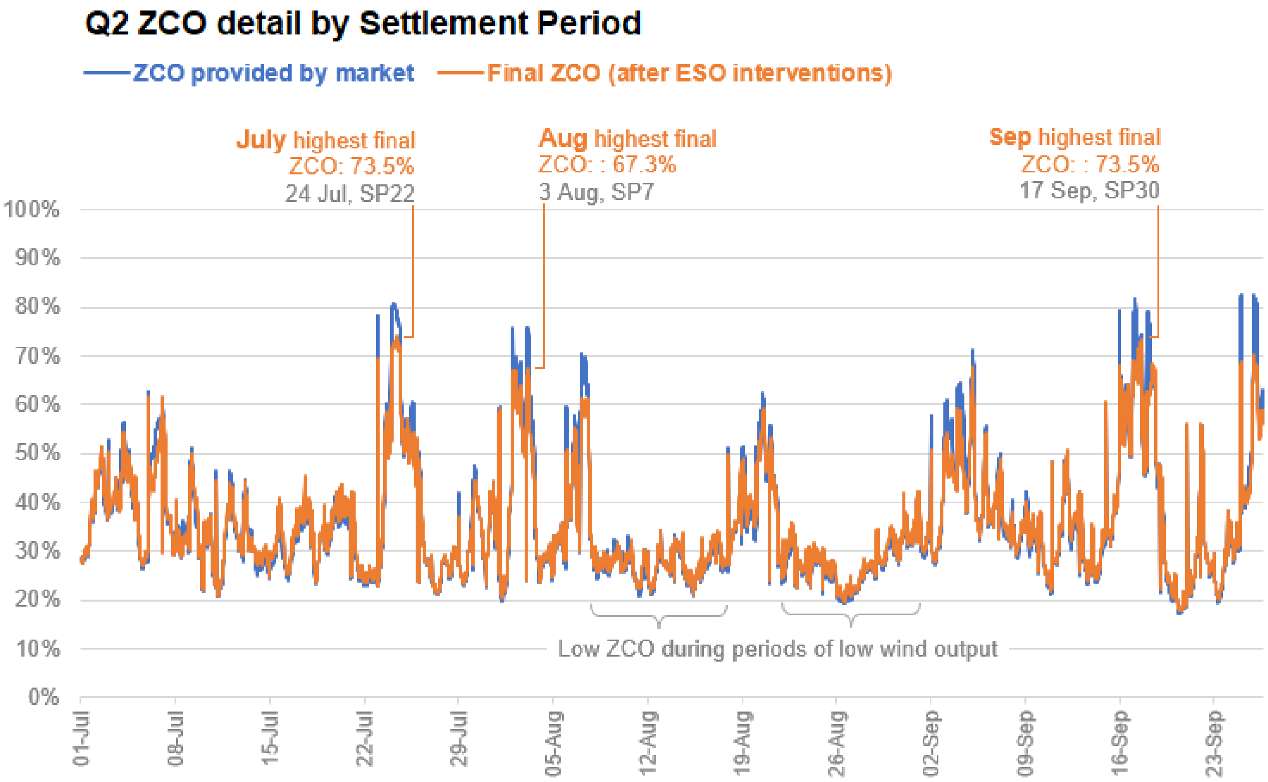


Figure 7: Q2 ZCO by Settlement Period, before and after ESO operational actions



Supporting information

In Q2 the highest zero carbon percentage outturn following ESO actions was 73.9%, on 24 July 2022, Settlement Period (SP) 22. This is lower than the highest ever zero carbon percentage outturn that the system has achieved which remains at 87.1% on 5 January 2022, SP 5. During that SP the market provided 93.0% ZCO, with actions taken by the ESO to manage the system reducing the final figure to 87.1%.

The key message for this quarter is that ZCO numbers are less than last year. This is because the market has dispatched an increased amount of carbon generation to support the increased interconnector exports. This increased scheduling of carbon generation reduces the ZCO provided by the market and hence the final ZCO numbers after our operational actions. If the additional carbon generation continues to be scheduled over the winter, the ZCO figures for Q3 and Q4 are also likely be suppressed.

Since April 2021, four Stability Pathfinder Phase 1 service providers have gone live at Rassau, Deeside, Keith and Killingholme. Together they increase system inertia by ~7.2GVAs, which could potentially remove the need to synchronise 2-3 Combined Cycle Gas Turbine (CCGT) units for inertia. This usually occurs over the summer and 'shoulder' months and would increase the ZCO figure by around 2.5% (depending on system conditions at the time).

As expected, the Q1 and Q2 ZCO figures have dropped back since Q4 2021-22. This is because the demand (not shown on the graph above) was lower in Q2 due to the warmer weather. When the demand is low but the renewable output remains high, the ZCO after ESO actions is often lower. This is because we still have to take similar sets of actions (to manage operability constraints such as voltage) but these actions represent a larger proportion of the overall amount of generation. In a similar manner, ZCO will drop at times of high solar output. This is because the majority of solar generation is embedded and hence excluded from ZCO. Therefore, at times of high solar output operational actions will still be needed, even though the ZCO figure provided by the market will appear relatively low as it will not include the solar generation.

The other point to note is how closely linked the ZCO figure is with wind output. The low wind spells during August are clearly visible on Figure 8 above, where the ZCO% drops to ~30%. Conversely, the maximum ZCO figures align with settlement periods of high renewable output, such as when it is windy.

RRE 1G Carbon intensity of ESO actions

September 2022 Performance

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

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

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

Figure 8: Monthly gCO2/kWh of actions taken by the ESO - two-year view

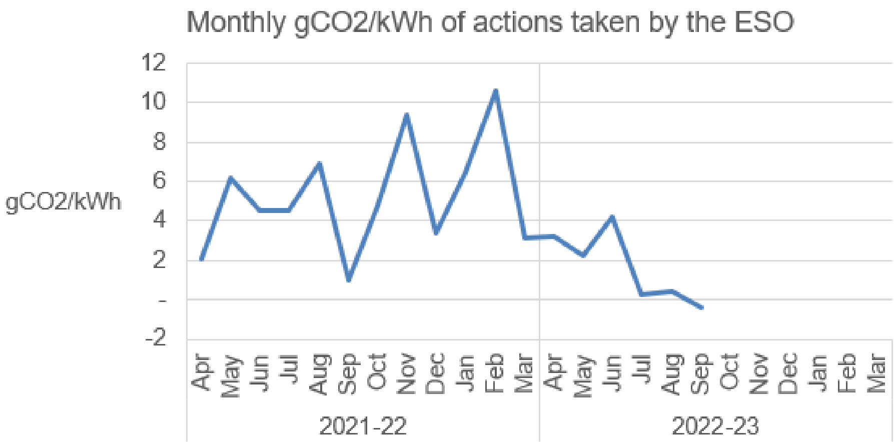


Table 10: gCO2/kWh of actions taken by the ESO

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

Supporting information

In September, the average carbon intensity of balancing actions was –0.4 gCO2/kWh. This was the lowest monthly average in the year so far.

For Q1 2022-23, the average carbon intensity was 3.2 gCO2/kWh, whereas the figures have been lower throughout Q2. The reduction in Q2 is because we are taking significantly fewer operational actions compared with previous months. In addition, carbon generation has been supporting the increased exports from GB and they also provide the needed network ancillary services. This reduces ESO interventions and means that if we do take operational actions pulling back carbon generation, the market carbon figures for this RRE will also reduce significantly. It can also go negative as it has done this month if we pull back carbon plant to create reserve or if the market is long.

In September, the largest decrease in carbon intensity due to ESO's actions was at 03:30 on 1st September with a minimum intensity of ESO actions at –7.9 gCO2/kWh. The minimum for the year so far is –26.2 gCO2/kWh on 29 May.

RRE 1H Constraints Cost Savings from Collaboration with TOs

April - September 2022-23 Performance

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

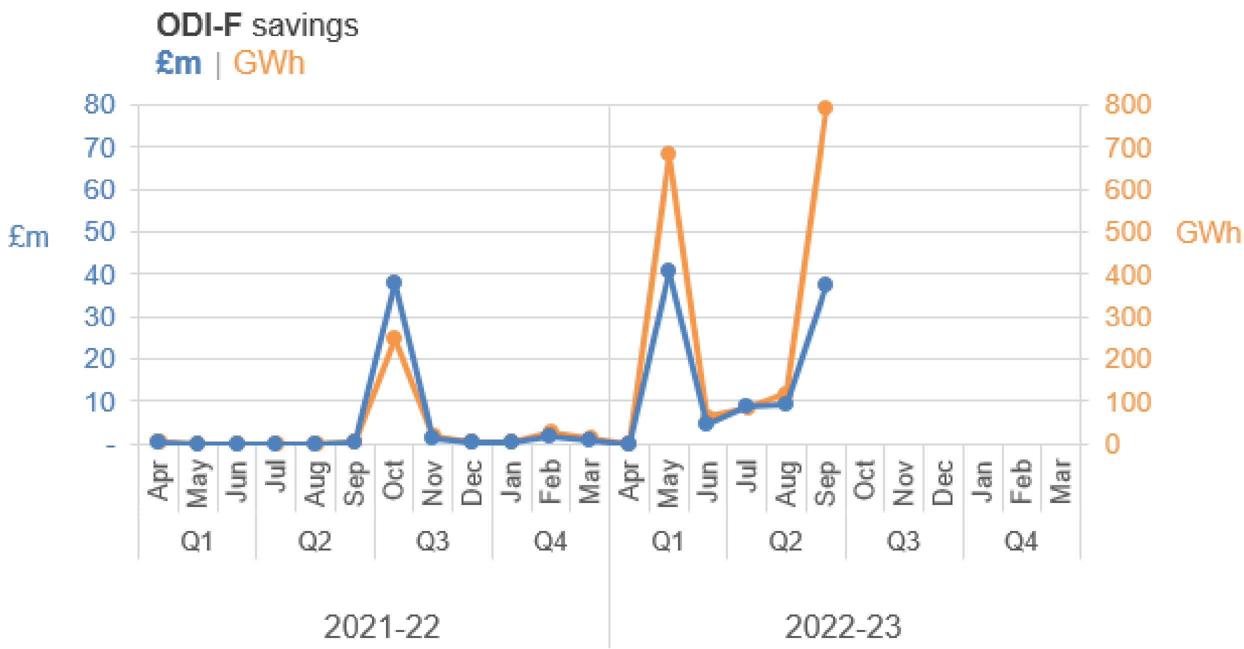
This Regularly Reported Evidence (RRE) measures the estimated £m avoided constraints costs through ESO-TO collaboration.

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

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

Figure 9: Estimated £m savings in avoided constraints costs (ODI-F) – two-year view

(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 are different from the ODI-F graph above.

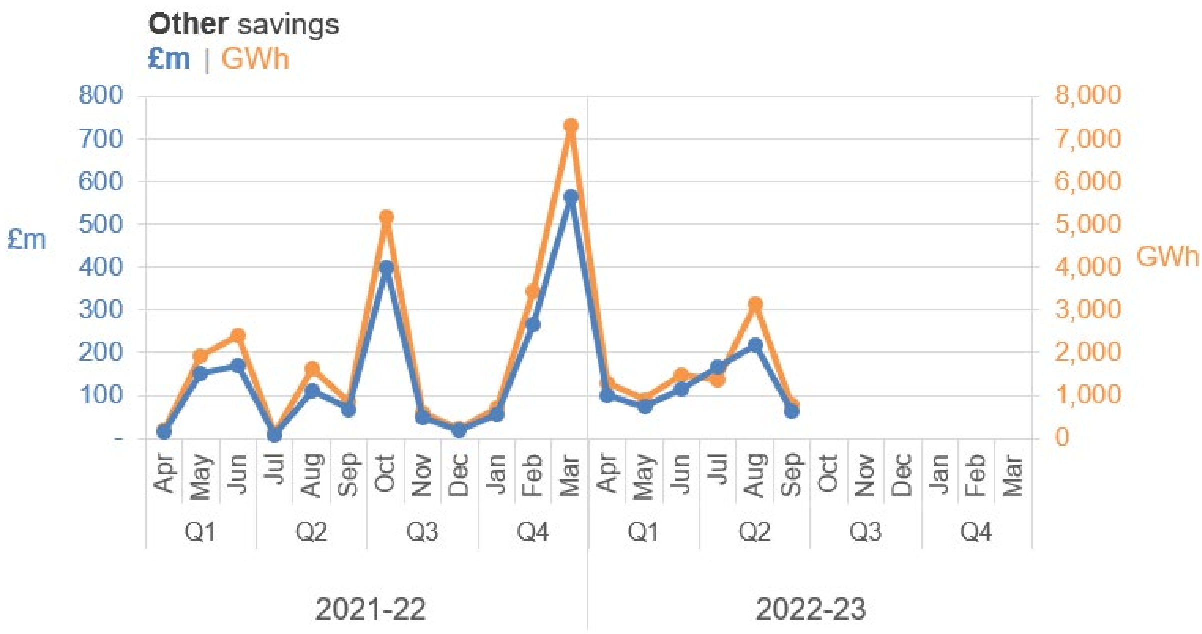


Table 11: Estimated £m savings in avoided constraints costs

		ODI-F savings		Other savings	
		£m	GWh	£m	GWh
2021-22	**Full Year**	**43**	324	**1,895**	24,613
2022-23	Apr	-	-	101	1,316
	May	41	685	74	913
	Jun	5	64	115	1,499
	Jul	9	83	167	1,388
	Aug	9	120	219	3,151
	Sep	38	792	62	768
	Year to date	**101**	**1,744**	**739**	**9,035**

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.

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 year. The process to evaluate the realised savings from this initiative has been improved this quarter to enable the accurate provision of cost savings for 6 of the 13 enhanced services. The remainder of these approved provisions are either ongoing or not yet in use and therefore have no cost savings against them at this time. As such, it is expected that STCP 11.4 constraint cost savings will be higher in Q3 and Q4 with potential for updates to the Q1 and Q2 data in subsequent reports. Some of these provisions, providing active savings across Q2, are highlighted below:

1. A modification to the overload protection settings was agreed with the TO for a circuit in Central Northern Scotland via STCP 11.4. This allowed for 500MW of additional renewable generation to be released to the market for the duration of the outage by increasing the limit on the B6 boundary. This additional power could be released as the modified protection allowed for nearby circuits to be loaded higher before the circuit would trip off from overload protection operation. Overall, this equated to an additional 120,000 MWh of renewable generation released or approximately **£9.2m** saved for the end consumer.
2. Forced cooling of super grid transformers for a substation in the North of England has been agreed by ESO between 6 April 2022 and 30 March 2023. This is to be activated pre-fault during periods of high constraints on the B6 boundary in order to reduce constraint costs. The savings from this initiative span the entire year and will be prorated over the full 12 months at end of year. They are therefore absent from the current Q2 figures but will be added at the end of Q4.
3. Three occasions of increasing rating enhancements on a key circuit in South England have been agreed allowing for increased capacity on the circuit during outages on nearby circuits. On the first occasion, the enhancement allowed for approximately 83,400 MWh to be released across the LE1 import boundary saving more than **£8.5m** for the end consumer. We plan to continue using an enhanced rating on the key circuit through to March 2023, with a forecast saving of **£38m** for September.

In Q2 2022-23, the NAP team has realised approximately **£55m** of constraint cost savings through STCP 11.4 from **995,000 MWh** of extra capacity released.

At the time of this report, there is an on-going enhancement on a circuit in the Northeast of England. The savings from this enhancement will be reported in Q3.

Other Savings (Customer Value Opportunities):

The Network Access Planning team has made good progress over the last three months. In collaboration with our stakeholders (TOs and DNOs) we have identified and recorded 136 instances where the ESO's actions directly resulted in adding value to end consumers, and its innovative ways of working facilitated increased generation capacity to connected customers.

We expect figures across all Quarters to increase in Q3 and Q4 as several ESO-led changes in the long-term planning period have not yet had full assessment of MWh and cost saving. Long-term plan changes are by nature more time consuming to accurately report on; the large volume of network changes cause limiting factors on the network to vary. Once the saving for these actions have been calculated, they will be added to the months in which the actions took place.

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 include:

- In August 2022, an outage in Southwest Scotland was aligned to another outage in the area. Both outages impacted the Western Link max loading and would require it to be at 0 MW. As a result of NAP's successful negotiations with the TO, the outages were aligned thereby releasing 448,800 MWh of extra capacity from the largely renewable generation mix in Scotland to England & Wales across the B6 boundary. This was a saving of approximately £35m to the end consumer.
- In August 2022, a running arrangement change, and circuit offload, suggested by ESO planning, was implemented for an outage combination in the East of England. This allowed for an increase on the EC5 limit by 1000 MW. This outage was extended by NGET by

approximately five weeks on top of its original duration. The changes proposed by ESO were still effective during this time and added an extra 396,000 MWh of savings during this unplanned extension. Overall, actions taken by ESO planning contributed to 900,000 MWh of savings in this case equating to around £49.5M of savings to the end consumer.

- In September 2022, an outage move was instigated by Network Access Planning. This was for part of an outage combination in Northern England to move to a low wind period. This improved the limit on a variation of B11 boundary and additionally allowed for increased loading on the Western Link High Voltage Direct Current cable improving the B7a limit in the high wind period that the outage was requested for. This was costed as a £14m saving due to 57,600 MWh increased capacity released.

These and many more represent a total of **5,307 GWh** (approximately **£448m**) of extra generation capacity realised in Q2, which would have otherwise been constrained at a cost to the consumer.

RRE 1I Security of Supply

April – September 2022-23 Performance

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

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

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

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

For this 2021-23 18-Month review, we also provide a summary of the ESO's compliance with its frequency control methodology and plans for any future changes to the methodology, as follows:

- The top three rows in the table below constitute the ESO's frequency management policy as set out in the FRCR. The bottom two rows are the monthly reporting requirements.
- The FRCR is produced at least annually. The latest version was published in April 2022 and can be accessed here. No changes were made to the frequency management policy in that version.

Table 12: Frequency and voltage excursions - two-year view

		2021-22	2022-23											
		TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
ESO policy as set out in the FRCR	Frequency excursions (more than 1.2 Hz away from 50 Hz)	0	0	0	0	0	0	0						
	Frequency excursions (more than 0.8 Hz away from 50 Hz)	0	0	0	0	0	0	0						
	Frequency excursions (more than 0.5 Hz away from 50 Hz for over 60 seconds)	0	0	0	0	0	0	0						
Incentives monthly reporting criteria	Instances where frequency was 0.3 – 0.5 Hz away from 50Hz for over 60 seconds	0	1	1	1	1	0	0						
	Voltage Excursions defined as per Transmission Performance Report[4]	0	0	0	0	0	0	0						

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

Supporting information

There were no reportable voltage or frequency excursions in September 2022.

In Q2 as a whole, there was one frequency excursion, in July. Due to extreme hot weather, on 19 July 2022 at 22:11, IFA2 tripped while exporting 1029MW from GB to France. Frequency increased to 50.352Hz and returned to operational limits by 22:15.

RRE 1J CNI Outages

September 2022 Performance

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

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

Table 13: Unplanned CNI System Outages (Number and length of each outage) – two-year view

	2021-22	2022-23											
Unplanned	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	0	0	0	0	0	0	0						
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0						

Table 14: Planned CNI System Outages (Number and length of each outage) – two-year view

	2021-22	2022-23											
Unplanned	TOTAL	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Balancing Mechanism (BM)	3[5] outages	0	0	0	1 outage 186 minutes	0	0						
Integrated Energy Management System (IEMS)	0	0	0	0	0	0	0						

Supporting information

There were no outages, either planned or unplanned, during September 2022.

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

Notable events during September 2022

We published our final RIIO-2 Business Plan 2 submission

On 31 August we published our final RIIO-2 Business Plan 2 (BP2) submission, which sets out our commitments from April 2023 to March 2025 as we look to accelerate the transition to net zero. In April, we shared a draft version of BP2 for consultation and our final plan reflects the stakeholder feedback we received as part of that process.

The opportunity for society and the wider British economy to benefit from the transition to net zero is significant – attracting inward investment, creating regional growth and jobs, improving our economic productivity, and providing benefits to communities and the environment. Britain's energy system is the cornerstone of this transition and, in 2021, the UK Government confirmed its ambition to fully decarbonise the electricity system by 2035. As the Electricity System Operator for Great Britain, we hold a unique position at the heart of the energy industry. We have an unparalleled opportunity to work with government and industry to realise the benefits of the energy transition, solve the challenges that lie in our path and accelerate progress towards a net zero future.

However, at the same time as stepping up to lead the energy transition over the longer term, we must also recognise the needs of energy consumers in the shorter term. We are submitting this plan against the backdrop of a major cost-of-living crisis, with energy costs at an unprecedented level. It is therefore vital that we minimise the cost and maximise the value of our operations wherever possible and redouble our efforts to keep costs down for consumers in the near term. We must also ensure that we contribute to a "just transition", where affordability and fairness remain imperatives to a successful net zero outcome.

Our BP2 plan sets out an ambitious suite of prioritised deliverables to make sure we can effectively fulfil our role in this transition and enable other industry participants to play their part. We have set out 11 clear priorities for BP2 to deliver the outcomes our stakeholders need from us over the next two years, grouped under the themes of delivering excellence in system operation, building efficient and effective markets, driving clarity in our path to net zero and enabling our organisation to perform. Together, our activities will drive over £2.8 billion of benefits for consumers over the 5 years of the RIIO-2 period.

The scale of change we need to deliver will demand a step-change in our own business – further embedding digital, data and technology capability, becoming the net zero employer of choice, driving rigour in our delivery approach, and maintaining the agility and flexibility to adapt as the energy system continues to change at pace.

A big part of this step-change will be our growth into the Future System Operator (FSO) for GB, transitioning out of National Grid plc, accelerating the evolution and expansion of our role within the industry, and establishing a new relationship with Government. We are hugely excited about the contribution we can make through BP2 and as we transition to the FSO.

We launched a new initiative to connect electricity generation to the transmission system faster

On 22 September we announced a new approach to connections management, which aims to remove stalled projects taking space on the register so that new projects can be connected more quickly.

The Transmission Entry Capacity (TEC) register orders the queue for connections to the national electricity transmission network and includes all projects that seek a connection offer.

1 October marked the start of a TEC Amnesty. Through this process, those on the register whose projects are unlikely to reach delivery are being given the opportunity to leave the register at no cost or at a reduced fee.

This event follows lengthy collaboration between the ESO, TOs and Ofgem, and looks to be an additional action in support to the delivery of Net Zero and the BEIS energy strategy. The TEC Amnesty is the last opportunity for customers to leave the queue on potentially more favourable terms than will be afforded under code modification CMP376. This modification, under the Connection and Use of System Code (CUSC), seeks to formally introduce Queue Management (QM) arrangements. QM will mean that projects which are ready to connect can do so ahead of those customer projects that may have applied earlier but are not ready or able to progress – currently the ESO are unable to prioritise the queue based on readiness to connect.

At the simplest level, if implemented, QM will introduce contractual milestones that customers must meet to retain their place in the connection queue, which will benefit everyone.

Latest set of updates to the Balancing Mechanism (BM) control room systems successfully implemented in IR2 release

We deployed the latest set of functional updates to the Balancing Mechanism (BM) systems in the control room in September. With this release we have further updated our Automatic Instruction Repeater (AIR) functionality, which was delivered in the R0 release in November 2021 and upgraded in the R1 release in May. We’ve also introduced new filtering functionality to control room screens to ensure our operational colleagues can more easily view and acknowledge the most important system events and remove unnecessary manual processes. In addition, we’ve fixed defects that have occurred and progressed with the decommissioning of redundant elements of the system. This is latest release under our agile approach to delivery. This work supports deliverable D1.1.5 and shows that the Balancing Programme continues to add value by making changes to our current systems that ensures continued safe, secure, and economic system operation while we develop and transition to our new tools.

Role 2 Market development and transactions

Metric 2A Competitive Procurement

Q2 2022-23 Performance

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

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

- For **Restoration**, there may be a significant lag time between when a contract is agreed and when it comes into effect. Therefore, in some cases actions we take in the current quarter may not impact Metric 2A until months or years later.
- For **Frequency Response** (FR), a lower '% of services procured through competitive means (auctions and tenders)' may appear to indicate that the market has become less competitive but can actually be a sign of the opposite. When the market becomes more competitive, the market price drops. This can lead to a reduction in overall competitively procured spend and therefore a lower percentage of total services that are competitively procured.
- **SO/SO Trades** are, by their nature, bilateral and therefore will always be reported as being bilaterally contracted. This means that in those quarters where more SO/SO trades are enacted, the percentage of Constraints & SO/SO Trades competitively procured is likely to reduce.

Figure 11: Percentage of £m spend by procurement method (Q2, July 2022 to September 2022)

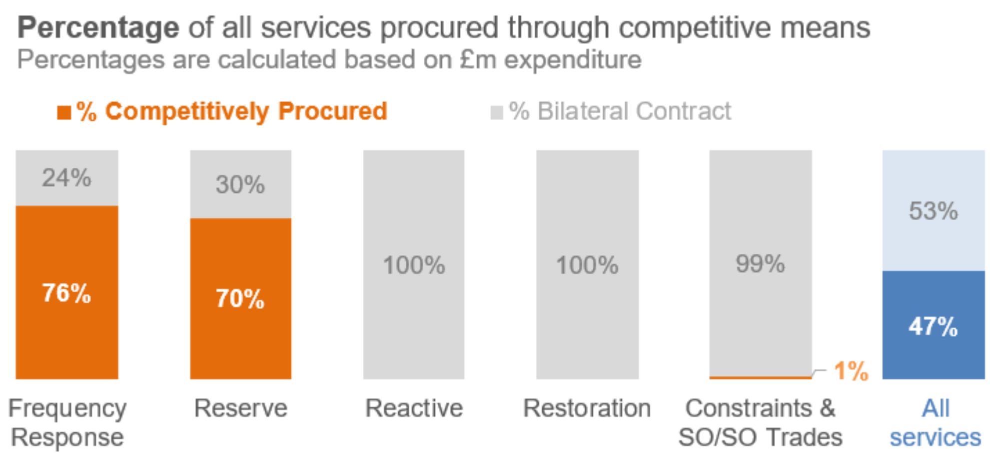


Figure 12: Absolute £m spend by procurement method (Q2, July 2022 to September 2022)

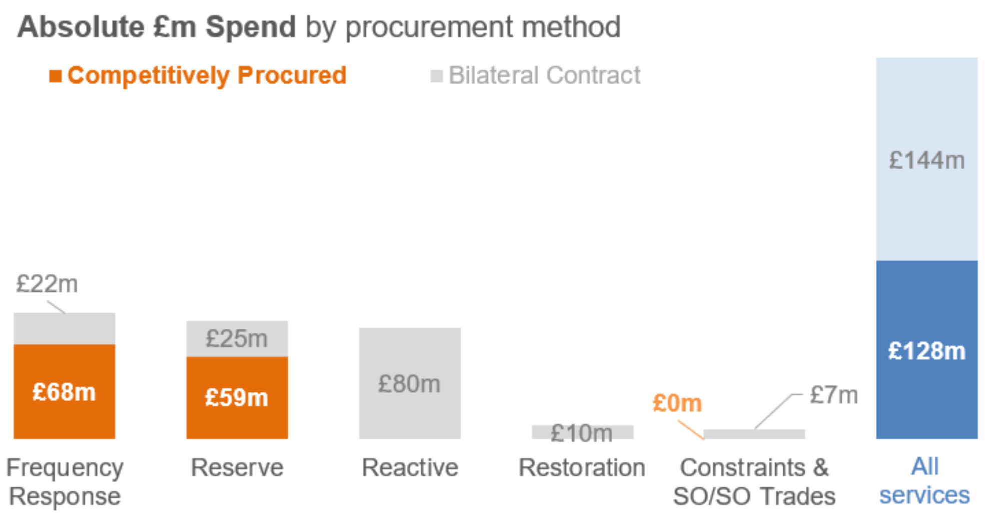


Table 15: Percentage of services procured through competitive means by Quarter

Year	2021-22					2022-23		
Services	**Q1**	**Q2**	**Q3**	**Q4**	**Full Year**	**Q1**	**Q2**	**YTD**
Frequency Response	91%	83%	84%	82%	85%	82%	76%	82%
Reserve	61%	62%	62%	66%	63%	60%	70%	60%
Reactive	0%	0%	0%	0%	0%	0%	0%	0%
Restoration	0%	0%	0%	0%	0%	0%	0%	0%
Constraints & SO/SO Trades	89%	376%[6]	42%	52%	118%[7]	29%	1%	29%
All services	**57%**	**61%**	**46%**	**44%**	**51%**	**46%**	**47%**	**46%**
Status (All services)	●	●	●	●	●	●	●	●

Performance benchmarks - **Year 1**

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

Performance benchmarks - **Year 2**

- ● **Exceeding expectations:** >75%
- ● **Meeting expectations:** 65-75%
- ● **Below expectations:** <65%

[6] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data. For reference, the absolute figures for Constraints & SO/SO Trades in Q2 2021-22 were: £15m competitively procured, -£11m bilateral contract.

[7] The figure is greater than 100% as Bilateral contract spend is negative (due to sending additional energy to Ireland via interconnectors in September). Absolute figures could be used instead, however this would be inconsistent with previously provided data. For reference, the absolute figures for Constraints & SO/SO Trades for full year 2021-22 were: £30m competitively procured, -£5m bilateral contract.

Supporting information

Q2 performance: **Below expectations**

The percentage of services procured through competitive means is 47%, which is in the 'below expectations' range of <65%.

Average Market Prices

	Q1	Q2	Q3	Q4
Dynamic Containment Low Frequency (DCL) (£/MW)	23.5	21.1		
Dynamic Containment High Frequency (DCH) (£/MW)	4.1	3.6		
Dynamic Moderation Low Frequency (DML) (£/MW)	5.2	5		
Dynamic Moderation High Frequency (DMH) (£/MW)	7.9	11.9		
Dynamic Regulation (£/MW) Low Frequency (DRL) (£/MW)	25.6	29.6		
Dynamic Regulation (£/MW) High Frequency (DRH) (£/MW)	26.2	18.4		
Optional Fast Reserve (£/MWh)	228.8	423.4		
STOR DA (£/MW)	4.6	10		

Frequency Response

The new frequency response product suite consists of Dynamic Moderation (DM), Dynamic Regulation (DR) and Dynamic Containment (DC). DM and DR are still in the initial stages of market growth and the requirement for these products will grow as Dynamic Firm Frequency Response (FFR) is phased out. The volume of prequalified MWs across the tendered Frequency Response products has continued to increase since their launch, resulting in greater market liquidity. The £22m / 24% non-competitive Frequency Response (see Figure 13 above) in Q2 is made up predominantly of Stability (£20.8m).

Reserve

The volume of Reserve procured has increased through Q2. This is associated with an increase in utilisation of Optional Fast Reserve.

Reactive

We continue to develop our thinking around market-based procurement of Reactive Power and are working with a partner company to explore potential reactive market designs through an innovation project. The Reactive Market Design Project phase 1 was concluded in March 2022 with the initial version of design and all outputs are shared on our website[8]. The next focus of the project is to assess the feasibility of implementing an enduring reactive market, and analyse what solutions are required to be developed. We will work with the stability market design project to further analyse some common questions on subjects such as Transmission Owner competition and broader asset eligibility. The output will then be used to inform a proposal about the plan on how the enduring reactive market can be delivered.

[8] https://www.nationalgrideso.com/balancing-services/reactive-power-services/reactive-reform-market-design

Currently the Reactive Power Market project team is reallocated to the Balancing Reserve project to provide support on the development of the service, lead industry engagement, run the consultation process and deliver the implementation of the service. The Reactive Power Market project was chosen due to the low immediate impact the project has on ESO costs for this winter. The project team will continue working on the Reactive market design after the new Balancing Reserve service is delivered.

Restoration

New rounds of competitive procurement events have been launched for 2022, with the South East region going first on 06 June 2022. This tender is the first time that Distributed Energy Resources (DER) can apply to provide Distribution-led restoration services to supplement the usual Transmission-led provisions. This tender, together with the Northern region tender which commenced on 17 October 2022, aims to bring the Distributed ReStart innovation project inputs into mainstream Electricity Restoration Service (ESR) process.

To supplement existing and new ESR provisions, a one-off nationwide wind-specific tender, for full service (transmission-led) requirements only, also launched on 8 August 2022. The primary driver for this initiative is to help meet our new Electricity System Restoration Standards launching in December 2026, by tapping into the 50GW of offshore wind generation forecasted by 2030.

Interest for these tenders from the energy industry has been high. For the South East expressions of interest, three times the number of providers came through than what was anticipated in that region and majority of these were for the distribution-led projects. This provides reassurance that providers understand the new requirements coming out of the Distributed ReStart part of the Restoration process and are willing to participate in this first of a kind restoration contract to provide restoration capability at a distribution level that can begin to energise up to transmission level. Similarly for the wind tender, a high number of expressions of interest were submitted from both offshore and onshore wind generators. Based on experience thus far, we are anticipating even higher number of interested parties for the Northern region tender covering five DNO areas in the North East, North West, South of Scotland, and North of Scotland.

Constraints & SO/SO Trades

Since April we have had four parties signed up to a Commercial Intertrip on the B6 constraint boundary. All parties have offered different arming fees. Instead of paying constraint costs to turn off generation when there is the risk of a fault, this technology provides an option of allowing generation to continue for longer, by increasing the constraint limit, resulting in reduced constraint costs which would ultimately be paid for by consumers. Across April – July 2022 we have reported consumer savings of £30m.

RRE 2B Diversity of Service Providers

April - September 2022-23 Performance

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

We report on the following services:

- Frequency Response (MFR, EFR, FFR, Dynamic Containment, Dynamic Regulation, Dynamic Moderation)
- 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

Service	Sub Service	Methodology
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).
	FFR	We report on the highest volume for each unit that has been contracted for a particular EFA block for the relevant month. The sum of those values is what we present on the monthly report.
	FFR Auction	
	Dynamic Containment	
	Dynamic Regulation	
	Dynamic Moderation	
	EFR	We report on contracted MW. This doesn't change from month to month unless a contract starts or ends.
Reserve	STOR (Short Term Operating Reserve)	We report on the total volume of pre-qualified units that are eligible to take part in the day ahead tenders. Not all prequalified units will win day ahead tenders.
	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.
Reactive	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).
Constraints	Constraints	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.

Figure 13: Total contracted volumes by service type by quarter

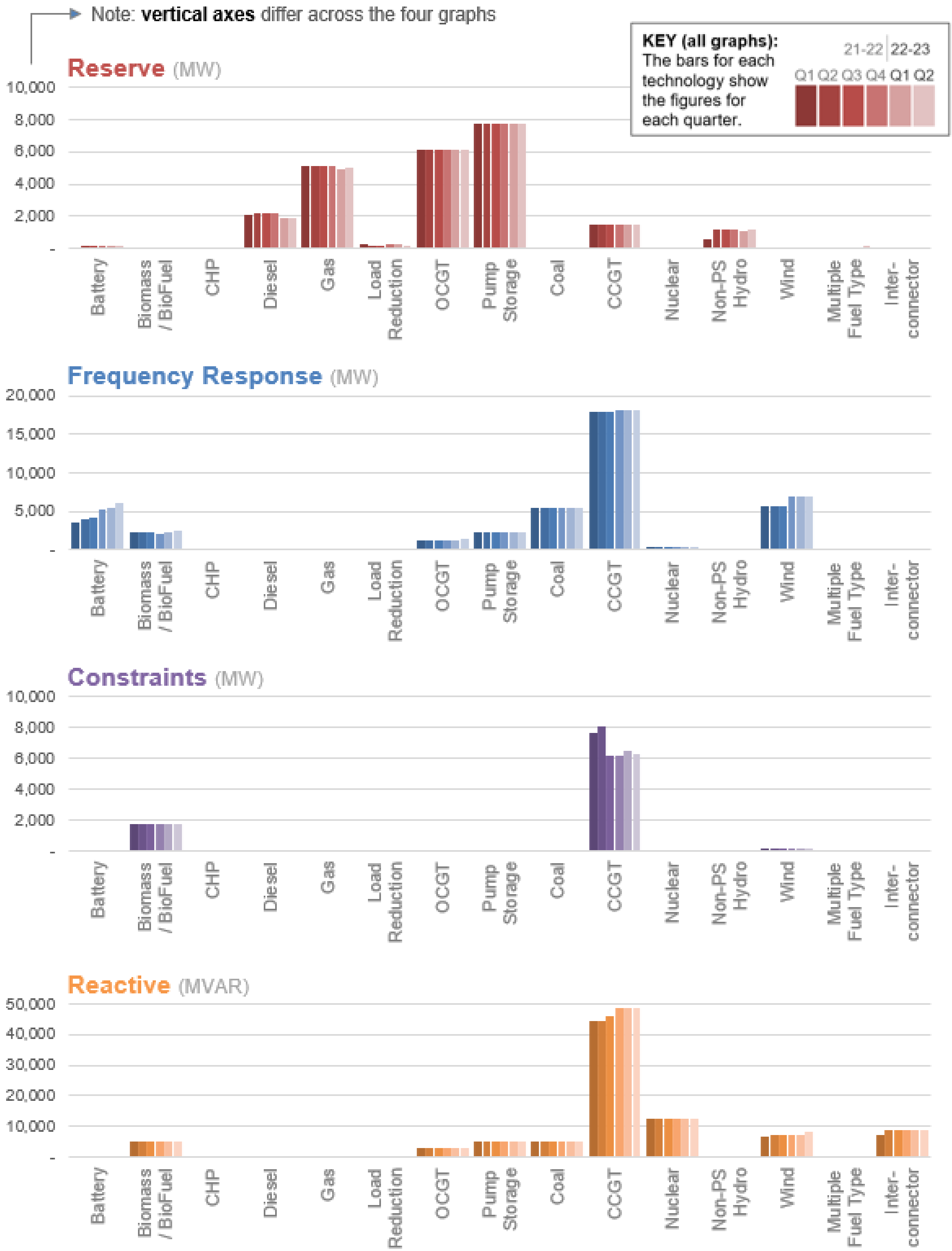


Table 16: Monthly contracted volumes provided to the ESO by service type

Reserve

MWs	Jul-22	Aug-22	Sep-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2022-23 Q2	2021-22	2022-23
Total	7,925	7,903	7,903	23,360	24,001	24,143	24,276	23,576	23,731	95,781	47,307
Battery	45	45	45	-	60	74	135	134	135	269	269
Biomass/BioFuel	-	-	-	-	-	-	-	-	-	-	-
CHP	-	-	-	-	-	-	-	-	-	-	-
Diesel	636	614	614	2,063	2,182	2,205	2,217	1,890	1,864	8,668	3,754
Gas	1,677	1,677	1,677	5,085	5,073	5,133	5,133	4,964	5,031	20,424	9,995
Load Reduction	50	50	50	216	150	195	255	225	150	816	375
OCGT	2,061	2,061	2,061	6,183	6,183	6,183	6,183	6,117	6,183	24,732	12,300
Pump Storage	2,600	2,600	2,600	7,800	7,800	7,800	7,800	7,716	7,800	31,200	15,516
Coal	-	-	-	-	-	-	-	-	-	-	-
CCGT	481	481	481	1,437	1,437	1,437	1,437	1,427	1,443	5,748	2,870
Nuclear	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	372	372	372	576	1,116	1,116	1,116	1,104	1,116	3,924	2,220
Wind	-	-	-	-	-	-	-	-	-	-	-
Multiple Fuel Type	3	3	3	-	-	-	-	-	9	-	9
Interconnector	-	-	-	-	-	-	-	-	-	-	-

Frequency Response

MWs	Jul-22	Aug-22	Sep-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2022-23 Q2	2021-22	2022-23
Total	14,372	14,432	14,346	39,001	39,296	39,343	41,967	42,282	43,150	159,607	85,432
Battery	1,990	2,050	1,946	3,644	3,979	4,126	5,336	5,382	5,986	17,085	11,368
Biomass/BioFuel	837	837	837	2,375	2,319	2,191	2,151	2,351	2,511	9,036	4,862
CHP	-	-	-	-	-	-	-	-	-	-	-
Diesel	43	43	61	130	130	192	188	183	147	640	330
Gas	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-
OCGT	443	443	443	1,119	1,119	1,119	1,119	1,189	1,329	4,476	2,518
Pump Storage	728	728	728	2,184	2,184	2,184	2,184	2,184	2,184	8,736	4,368
Coal	1,782	1,782	1,782	5,346	5,346	5,346	5,346	5,346	5,346	21,384	10,692
CCGT	6,024	6,024	6,024	17,997	17,997	17,997	18,047	18,072	18,072	72,038	36,144
Nuclear	92	92	92	276	276	276	276	276	276	1,104	552
Non-PS Hydro	70	70	70	210	210	210	210	210	210	840	420
Wind	2,343	2,343	2,343	5,643	5,643	5,617	7,029	7,029	7,029	23,932	14,058
Multiple Fuel Type	20	20	20	77	93	85	81	60	60	336	120
Interconnector	-	-	-	-	-	-	-	-	-	-	-

Constraints

MWs	Jul-22	Aug-22	Sep-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2022-23 Q2	2021-22	2022-23
Total	2,705	2,705	2,705	9,499	9,863	8,055	8,055	8,309	8,115	35,472	16,424
Battery	-	-	-	-	-	-	-	-	-	-	-
Biomass/BioFuel	595	595	595	1,785	1,785	1,785	1,785	1,785	1,785	7,140	3,570
CHP	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-
OCGT	-	-	-	-	-	-	-	-	-	-	-
Pump Storage	-	-	-	-	-	-	-	-	-	-	-
Coal	-	-	-	-	-	-	-	-	-	-	-
CCGT	2,095	2,095	2,095	7,645	8,070	6,225	6,225	6,455	6,285	28,165	12,740
Nuclear	-	-	-	-	-	-	-	-	-	-	-
Non-PS Hydro	-	-	-	-	-	-	-	-	-	-	-
Wind	15	15	15	69	8	45	45	69	45	167	114
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-
Interconnector	-	-	-	-	-	-	-	-	-	-	-

Reactive

MVARs	Jul-22	Aug-22	Sep-22	2021-22 Q1	2021-22 Q2	2021-22 Q3	2021-22 Q4	2022-23 Q1	2022-23 Q2	2021-22	2022-23
Total	32,182	32,182	32,182	89,467	91,602	92,938	95,661	95,685	96,546	369,668	192,231
Battery	-	-	-	-	-	-	-	-	-	-	-
Biomass / BioFuel	1,734	1,734	1,734	5,202	5,202	5,202	5,202	5,202	5,202	20,808	10,404
CHP	-	-	-	-	-	-	-	-	-	-	-
Diesel	-	-	-	-	-	-	-	-	-	-	-
Gas	-	-	-	-	-	-	-	-	-	-	-
Load Reduction	-	-	-	-	-	-	-	-	-	-	-
OCGT	967	967	967	2,901	2,901	2,901	2,901	2,901	2,901	11,604	5,802
Pump Storage	1,630	1,630	1,630	4,890	4,890	4,890	4,890	4,890	4,890	19,560	9,780
Coal	1,731	1,731	1,731	5,193	5,193	5,193	5,193	5,193	5,193	20,772	10,386
CCGT	16,164	16,164	16,164	44,496	44,496	45,820	48,468	48,492	48,492	183,280	96,984
Nuclear	4,095	4,095	4,095	12,285	12,285	12,285	12,285	12,285	12,285	49,140	24,570
Non-PS Hydro	189	189	189	567	567	567	567	567	567	2,268	1,134
Wind	2,753	2,753	2,753	6,576	7,311	7,323	7,398	7,398	8,259	28,608	15,657
Multiple Fuel Type	-	-	-	-	-	-	-	-	-	-	-
Interconnector	2,919	2,919	2,919	7,357	8,757	8,757	8,757	8,757	8,757	33,628	17,514

Supporting information

Reserve

The STOR service continues to be delivered by the more traditional technologies (CCGT, OCGT, Gas Reciprocating Engines and Diesel) . Whilst we have seen some interest from new technologies (battery storage and aggregated demand management), they have yet to register for the service and may elect to wait for the new reserve products which are better aligned to new technologies (Wind, Solar, BESS, etc) and smaller plant (lower minimum entry capacity and multiple, shorter windows). For Fast Reserve, we still procure an optional service where a small number of (prequalified) more traditional technologies contract on the day to make their capacity available should it be required.

Frequency Response

Frequency services are delivered by providers who are awarded contracts through a competitive tendering process (which includes the daily auctions) that take place on a daily basis. The unit base is a mix of BM and Non-BM, primarily DNO connected, however we are starting to see TO connected storage assets that are providing frequency services. The increase in batteries providing tendered frequency services continues, with this asset type now making up the majority of the MWs provided by frequency services.

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.

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 Peak Gen shunt reactor service went live in Q1 2022-23, and we expect the Zenobe Battery to start delivering in Q3 2022-23 to meet a need in the Mersey region. In January 2022 we also awarded contracts to meet reactive needs in the Pennines region that are due to commence in 2024-25.

RRE 2E Accuracy of Forecasts for Charge Setting – BSUoS

September 2022 Performance

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

Figure 14: Monthly BSUoS forecasting performance (Absolute Percentage Error) – two-year view

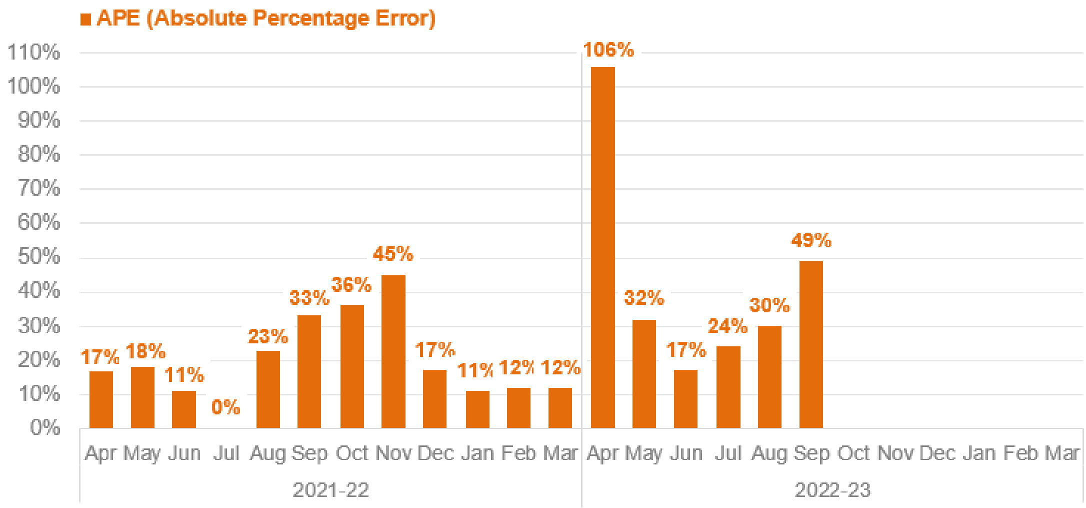


Table 17: Month ahead forecast vs. outturn BSUoS (£/MWh) Performance[9] - one-year view

	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	Jan	Feb	Mar
Actual	5.3	6.0	9.4	10.3	9.2	8.5						
Month-ahead forecast	11.0	9.0	7.7	7.8	11.9	12.7						
APE (Absolute Percentage Error)[10]	**106%**	**49%**	**17%**	**24%**	**30%**	**49%**						

Supporting information

The September outturn APE% was 49%, which is the second highest of 2022-23 so far.

When we forecast September at the beginning of August, there was still a wide range of possibilities that could outturn due to uncertainties in the weather and wholesale markets. The eventual APE% resulting from the outturn September costs was higher than average, and at around the level we would expect to see only about once in every ten months.

Price volatility was the main driver of the variance, with the wholesale electricity prices outturning 25% lower (at £261/MWh) than the market forward price at the beginning of August (£347/MWh).

[10] 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.

Impact of the new BSUoS dataset on forecast accuracy

Our new BSUoS model was developed as part of CUSC code modifications CMP361 & CMP362: 'BSUoS Reform: Introduction of an ex ante fixed BSUoS tariff & Consequential Definition Updates'.

We ran the new model alongside the old model over the period April 2021 to December 2021 and compared their performance. Over that period the new model had a mean absolute percentage error (MAPE) of 21% compared to 30% for the old model. Performance over the period was heavily skewed by November 2021 which had very high costs, and removing that month from the analysis gives a MAPE of 18% for the new model vs 26% for the old model. Therefore we're confident that the new model is more accurate. The new model also reacts quickly to changing circumstances.

The old model was switched off at the end of December 2021, and the new model has been used for the forecasts from January 2022 onwards.

We held a webinar to introduce the new model on 27 June 2022. The webinar recording and documents are available:

1. Pre-webinar document
2. Webinar slides
3. Webinar recording
4. Webinar Q&A document

Notable events during September 2022

Autumn Markets Event

On 28 September, we hosted our Autumn Markets Forum. Our events help attendees learn about how the ESO is developing new and existing markets to enable the transition to net zero, as well as provide a view of how ESO is adapting to evolving market conditions.

The great turnout, with 130 attending in person and 288 via the livestream, gave us the opportunity to engage in conversations with a range of stakeholders. The forum covered the following topics:

- Short-term priorities: Approach to Winter 2022
- Medium-term priorities: Updates on new projects such as Demand Flexibility and Firm Regulating Reserve
- Long-term priorities: Net Zero Market Reform
- In-person breakout collaborative sessions

You can watch recorded presentations and download the material from the event on our website here.

CMP395: Cap BSUoS costs and Defer payment to 2023/24 to protect GB customers

Industry raised an urgent modification to cap BSUoS in order to help support reducing the impact of the cost of living crisis. BSUoS costs have been increasing in both volatility and price over the past year. Market participants include a risk premium to cover BSUoS costs. The BSUoS price cap aims to bring certainty to suppliers and generators such that risk premia can be reduced as they are now less exposed to exceptional BSUoS costs, supporting lowering prices over the winter period. OFGEM approved WACM3, a £40/MWh cap, with a £250m fund being made available between October 2022 and March 2023. The costs will be recovered from Industry from April 2023. The ESO worked proactively with industry to quickly develop a set of solutions through an urgent code modification process. Daily reporting has been implemented to aid transparency of when the cap is utilised, and how much of the fund is used up.

Proposal for Winter Contingency service cash-out protection

Due to the potential tight margins this winter, the ESO has entered into bi-lateral contracts with Coal providers, to provide significant non-gas GW if required. We refer to this service as the Winter Contingency Service (WCS).

As per the agreed contract, this service must be dispatched at £0/MWh to minimise the impact on cash-out and restrict payments to the providers of the service which would create unnecessary cash flows. However, in some scenarios where there is severe scarcity in the GB wholesale markets, it could lead to the WCS setting the cash out Price at £0/MWh for all impacted settlement periods. To solve this issue the ESO has listened to industry feedback and raised an urgent BSC modification (P447) and an urgent C16 change consultation in order to put in place a legal workaround of removing the £0 action and manually adding in a repriced system flagged volume at £99,999. This will allow the volumes to be removed by Elexon via the normal cash out calculation process. This should protect the industry from adverse settlement prices if this service is called upon during this winter.

Role 3 System insight, planning and network development

RRE 3A Future savings from Operability Solutions

April – September 2022-23 Performance

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

i. Saved balancing costs
ii. Saved infrastructure costs
iii. Monetised carbon reductions

Below we also set out how we have calculated the forecast benefits.

i. Saved balancing costs

Table 18: Estimated saved balancing costs in 2021-22 from new operability measures

Operability Solution projects	a **Contract Cost** (£m)	b **Counterfactual Spend** (£m)	b - a **Savings** (£m)
Stability Pathfinder Phase 1	54.7	63.3	**8.6**
Mersey Voltage Pathfinder	1.0	13.6	**12.6**
Loss of Mains programme	4.0	10.0	**6.0**
TOTAL	**59.7**	**86.9**	**27.2**

Table 19: Estimated saved balancing costs in 2022-23 from new operability measures

Operability Solution projects	a **Contract Cost** (£m)	b **Counterfactual Spend** (£m)	b - a **Savings** (£m)
Stability Pathfinder Phase 1	109.3	126.6	**17.3**
Mersey Voltage Pathfinder	1.9	27.2	**25.3**
Loss of Mains programme	26.8	44.4	**17.6**
B6 Boundary Constraint Management Pathfinder (April to July only)	4.1	33.7	**29.6**
TOTAL	**142.1**	**231.9**	**89.8**

Supporting information

Pathfinder Projects

With the successful implementation of commercial service contracts under Stability Pathfinder phase 1 and the Mersey Voltage Pathfinder for another year, we expect estimated balancing cost savings of £17.3m and £25.3m respectively for 2022-23.

The savings are estimated based on the counterfactual spend forecast if the relevant new operability solution was not brought in. We then annualise the figure through the contract length based on the assumption that all contracts will be delivered on their contractual dates. The Stability Phase 1 contract was awarded in April 2020 with six years contract length, and Mersey Voltage contract was awarded in May 2020 with nine years contract length. Both have been implemented and given estimated saving figures for both 2021-22 and 2022-23.

In the last six months, we have also awarded contracts for the B6 (English/Scottish boundary) Constraint Management Pathfinder, Pennine Voltage Pathfinder and Stability Pathfinder phase 2 (Scotland). The commercial solutions awarded under B6 Constraint Management Pathfinder have already started to provide service as requested by ESO, which generated great balancing cost savings between April 2022 to July 2022. We will continue to monitor the savings and update then in the next report. The Pennine High Voltage Pathfinder has procured 700 MVAr reactive power capability in the Pennines regions (North East and West Yorkshire) between 2024 and 2034. The Stability Pathfinder Phase 2 has procured 8.4 GVA of Short Circuit Level (SCL) and 6 GVA seconds of inertia in the Scottish regions from April 2024 to March 2034 to manage stability on the system. We expect both will deliver significant amount of balancing cost saving from April 2024 onwards, which will be reported in subsequent reports.

Loss of Mains programme

The Accelerated Loss of Mains Change Programme has progressed well. Over 8,000 generation sites have completed protection changes with support from the programme, with a combined capacity of 12.8GW. With the addition of generators contacted and known to have achieved compliance, this takes the total engaged to 23.1GW, or 87% of the total generation capacity that is within scope. These changes have already impacted on Balancing Costs and give an estimated saving of £17.6m for 2022-23.

Method of calculating benefits

For the above projects (Pathfinder projects and Loss of Mains Program), the counterfactual spend is the forecast cost of balancing the system based on the forecast of future system conditions such as those contained within the Future Energy Scenarios (FES) and other relevant market intelligence information, if no new commercial solutions were implemented. After introducing the new commercial solutions through an open market tender, that counterfactual spend would disappear, but there would be additional contract costs relating to the payment for the service providers who deliver those new commercial solutions. Therefore, the savings are calculated as the difference between the counterfactual spend and the contract cost.

ii. Saved infrastructure costs

a) RDPs

The value of RDP avoided asset build was quoted as £12.9m in the ESO RIIO-2 Business Plan Annex 2 Cost Benefit Analysis Report[11]. This will vary depending on the scope of the RDP.

Supporting information

All RDPs undergo a cost benefit analysis as part of the initial development process. As we progress new RDPs we will provide details of assessments undertaken, starting with RDP3 in the End of Scheme report.

b) Enhanced Operability Assessment

The increasing volume of generation capacity to be connected on the South East coast has triggered major transmission reinforcement works which could cost hundreds of millions of pounds and take around 8 -10 years to build. The ESO undertook an enhanced operability assessment which identified the possibility of implementing an operational solution that can bring forward the connection dates of some customers on a non-firm basis ahead of the delivery of the enabling works. The details of the technical solution as well as the customers whose connection dates can be brought forwards are being worked on and we will report the outcome in due time. This approach will enable a flexible and efficient use of the available network capacity to be used by projects which are ready to connect without undue delays.

iii. Monetised carbon reductions

a) Pathfinders

Stability Pathfinder Phase 1	Unit	2022-23	2023-24	2024-25	TOTAL
Avoided CCGT output in MW	MW	1,250	1,250	1,250	3,750
Avoided CCGT output in TWh (assuming **30%** availability during the year)	TWh	3.3	3.3	3.3	9.9
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	n/a
CO2 in tonnes	tCO2	1.3m	1.3m	1.3m	3.9m
Carbon price (RIIO-2 CBA)	£/tCO2e	15.3	15.8	16.6	n/a
Savings	**£m**	**20**	**20**	**22**	**62**

[11] https://www.nationalgrideso.com/document/158061/download

Supporting information

As no new services have been commissioned under our Pathfinder projects during 2022-23, the carbon savings reported here are the same as those that were in place during the previous reporting period (Mersey and Stability phase 1).

In Stability Pathfinder Phase 1, the ESO procured 12.5GVAs of inertia. If the Stability Pathfinder had not taken place, the most economic option for increasing system inertia would be for the ESO to bring Combined Cycle Gas Turbines (CCGTs) onto the system.

To provide 12.5GVAs of inertia, it would be necessary to bring approximately 5 x 250MW units onto the system. In order to calculate the carbon reductions associated with the Stability Pathfinder, we assume that when the Pathfinder providers are supplying inertia, they displace CCGTs, as synchronising this fuel type is usually the most cost-effective way to raise system inertia. However, their services are not always needed as the market can provide sufficient inertia avoiding the need for any additional operational actions.

We have used the ESO's Carbon Intensity Forecast methodology to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. We have subsequently used the BEIS short-term traded carbon values (converted from calendar years to financial years) to convert this into monetised carbon savings. Therefore, across 2022-2025 this equates to an estimate of:

- Avoided generation from CCGTs: 9.9TWh
- Avoided CO2: 3.9 Tonnes
- **£ Savings: £62m**

Short-Term Mersey Pathfinder	Unit	2020-21	2021-22	2022-23	TOTAL
CCGT generation output avoided in MW	MW	220	220	220	660
CCGT generation output avoided in GWh (220 nights at 8 hours per night)	GWh	387	387	387	1161
Carbon intensity for Gas (Combined Cycle) from ESO Carbon Intensity Forecast Methodology	gCO2/kWh	394	394	394	n/a
CO2 in tonnes	tCO2	152,557	152,557	152,557	457,671
Carbon price (RIIO-2 CBA)	£/tCO2e	14.0	14.7	15.3	n/a
Savings[12]	**£m**	**2.1**	**2.2**	**2.3**	**6.6**

[12] Total savings figures are rounded to 1 decimal place. Unrounded figures are 2,135,795 (2020-21), 2,242,585 (2021-22) and 4,378,380 (Total)

Supporting information

As no new services have been commissioned under our Pathfinder projects during 2022-23, the carbon savings reported are those that were in place during the previous reporting period (Mersey and Stability phase 1).

The Short-Term Mersey Pathfinder is a contractual arrangement where a contract with Inovyn avoids the need to bring on generation at Rocksavage power station (a CCGT).

The Stable Export Limit (SEL) of Rocksavage power station is 220MW. It is generally at night-time that it is necessary to enact the Pathfinder contract: we have assumed that this is an 8-hour period.

We have used the same assumption as were used in the Mid-Scheme Report, to calculate the MWh of CCGT generation avoided, and the ESO's Carbon Intensity Forecast methodology 93 to convert the MWh of avoided CCGT generation into avoided tonnes of carbon. We have subsequently used the BEIS short-term traded carbon values 94 (converted from calendar years to financial years) to convert this into monetised carbon savings.

b) RDPs

Table 20: Carbon savings calculation for UKPN:

UKPN	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	YTD
Additional capacity connecting per year	MW	510	302	99	100	-	1011
Cumulative additional capacity	MW	510	812	911	1011	1011	1011
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	1,787	2,847	3,192	3,541	3,541	14,909
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	112	88	89	88	86	N/A
CO2 in tonnes	tCO2	199,937	251,701	284,261	312,076	302,975	1,350,950
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	N/A
Savings	**£m**	**2.9**	**3.8**	**4.5**	**5.2**	**5.8**	**22.3**

Table 21: Carbon savings calculation for NGED:

NGED	Unit	2021-22	2022-23	2023-24	2024-25	2025-26	YTD
Additional capacity connecting per year	MW	9	463	357	157	219	1205
Cumulative additional capacity	MW	9	472	829	986	1205	1205
Additional capacity in GWh (8760 hours / year and Load factor of 40%)	GWh	33	1,656	2,906	3,455	4,223	12,273
Carbon intensity 'Steady Progression' (FES 21)	gCO2/kWh	112	88	89	88	86	N/A
CO2 in tonnes	tCO2	3,649	146,389	258,840	304,493	361,261	1,074,632
Carbon price (RIIO-2 CBA)	£/tCO2e	14.7	15.3	15.8	16.6	19.2	N/A
Savings	**£m**	**0.1**	**2.2**	**4.1**	**5.1**	**7.0**	**18.4**

Supporting information

Updated connection data has been used as provided through the Appendix G process. We have also added connected generation volumes in the RIIO-2 period where this data is available.

RRE 3B Consumer Value from the NOA

April - September 2022-23 Performance

This Regularly Reported Evidence measures the level of forecast savings created by the ESO through actions to encourage alternative solutions in the NOA (not including NOA pathfinders).

In addition to encouraging alternative solutions in the NOA, the ESO also carry out considerable activities on behalf of the TOs and other stakeholders to ensure maximum value for the consumer, such as bespoke cost benefit analysis to find the most cost-effective solution power system reinforcement.

Below we set out how we have calculated the forecast benefits.

Supporting information

The NOA 2021/22 Refresh[13] data shows a gross benefit of at least **£212m**, over the RIIO-2 period. There is no change from the previous report since the NOA 2021/22 Refresh provides the same recommendations with NOA 2021/22 over the RIIO-2 period.

NOA Methodology improvements

During the last six months, we changed the 2022 methodology in the key areas outlined below. These changes will be applied in future NOAs:

- The changes to the NOA recommendations include removing “Delay” and separating “Proceed” into “Proceed –Critical” and “Proceed –Maintain”. This is to distinguish options which require investment in the next financial year from those that require continued planning but may be permitted to slip by up to one year. This improvement was conducted in response to consultation feedback received on the NOA 2021 methodology.
- The scope of the methodology was amended to enable the ESO to work with the TOs to assess which options may ease constraint costs if their Earliest in Service Date (EISD) could be advanced. The results of the analysis are shared with the relevant TO but not included in the NOA publication.
- The ESO has reviewed its requirements for an economic modelling tool and has completed a competitive tender process. After thorough evaluation, we have selected Plexos to replace BID3. This gives us additional features which we will develop with the provider, Energy Exemplar. We are building our model in Plexos and comparing the output with BID3, to ensure consistency. It is likely that the economic modelling for the next NOA report will use Plexos and we have amended the methodology to reflect this.
- The ESO supports Ofgem's intention of enabling more organisations to deliver network reinforcements in the form of early competition. The legislation to enable this was set out in the Energy Security Bill. The ESO is establishing a tender process which will cover the design, build and operation of reinforcements.

Interested Persons’ Process Improvements

The Interested Persons’ (IP) options process is a submission process allowing options from non-TO parties to be submitted and potentially assessed in the annual NOA process. This is designed to increase the diversity of options considered within the NOA process through academic and industry participation. The revised process accommodates option proposals at any time while requiring them to be viable in time for annual NOA submission deadlines. The revised process supports a collaborative approach to developing the option proposals by enabling a constant dialogue with the industry. We will also be working in partnership with Interested Persons to explore how their solutions can provide benefit to consumers and the whole system. We have provided clarity around the option delivery of Interested Persons' submissions - options will be led by either the ESO or incumbent TO in collaboration with the Interested Person, depending on who is best placed to support. The Interested Persons’ process will be

[13] The NOA 2021/22 Refresh replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND).

undergoing review to further increase option diversity within the transitional centralised strategic network plan (tCSNP) and following it, centralised strategic network plan (CSNP)[14].

Illustrative example:

The following is a worked example using dummy data to illustrate our methodology for calculating the benefit of the ad-hoc CBAs. This example is the same one used in our previous RIIO-2 reports.

As we don't know for certain what the energy landscape will look like in the future, we use the four FES scenarios to give the likely range of possibilities. The table below shows the potential range of costs for two options, across four FES scenarios. These costs are the sum of the capital costs of building the option (CAPEX) and the operational costs for running the network (OPEX) with that option in place. The CAPEX is fixed across the four FES scenarios as those costs are not dependent on the variables within the FES, such as generation connected to the network. Conversely, the OPEX costs change per FES scenario as it is dependent on the variables within the FES, such as generation connected to the network. Therefore, options may have different total costs in different scenarios, as seen below.

Dummy data – total costs for two options across four FES scenarios

	FES scenarios			
Option	**Steady Progression** (£m)	**System Transformation** (£m)	**Consumer Transformation** (£m)	**Leading the Way** (£m)
1 (TO preferred)	140	130	120	125
2	100	100	100	110

The lowest possible cost across these two options and four scenarios is **£100m.**

Dummy data – 'Regret' analysis for two options across four FES scenarios

We then calculate the difference between each of the possible costs and the lowest cost option (in this case, £100m). This difference is what we call the 'Regret' figure (see table below). For example, for Option 1, using Steady Progression, the 'Regret' figure is calculated as:

Estimated cost - lowest cost option = **Regret**

£140m - £100m = **£40m Regret**

In other words, if option 1 was built and the energy network in the future was similar to the FES scenario Steady Progression, the regret would be £40 million. This is because option 2 could have been £40 million less expensive.

Finally, we establish the 'Worst Regret' figure, which is the most expensive possible outcome for each of the two options (i.e. the worst for the consumer). See below:

Option	**Steady Progression** (£m)	**System Transformation** (Regret in £m)	**Consumer Transformation** (£m)	**Leading the Way** (£m)	**Worst Regret** (£m)
1 (TO preferred)	40	30	20	25	**40**
2	-	-	-	10	**10**

[14] Ofgem have launched their Electricity Transmission Network Planning Review (ETNPR), aiming to enhance the network planning processes to implement enduring arrangements for the CSNP. The CSNP is envisaged to take a GB-wide holistic view to develop an optimised plan for taking forward network investment, a significant evolution of the NOA process.

In this example the ‘Worst Regret’ for option 1 is **£40m** and for option 2 is **£10m**. Therefore, we would recommend option 2, as it has the least ‘worst regret’.

We calculate the consumer benefit to be **£30m**, which is the difference between our recommended option and the TO’s initial preferred option, as can be seen below.

Recommended option's Worst Regret - TO preferred option's Worst Regret = **consumer benefit**

£40 million - £10 million = **£30 million consumer benefit**

Consumer benefit from Large Onshore Transmission Investment (LOTI) CBAs

A key role for the ESO is undertaking independent cost benefit analysis for transmission investments, to support TOs in their need cases for major reinforcements. Over the last six months, we have undertaken significant studies for all three TOs, to support them delivering the network capacity needed to enable the low carbon transition.

We have calculated the consumer benefit of our analysis as **£1,085m** across 4 projects over the six month period. Details of the specific schemes we have supported are:

- For NGET we have worked together to define the CBA for the Final Needs Case for Yorkshire Green Energy Enablement project (a key onshore enabler for the Eastern Links). We have also undertaken analysis to support options development on other key projects in the North and East of England, which will provide additional capacity on key boundaries to facilitate increased volumes of renewable generation. The preferred option was found to provide **£207m** of pounds worth of benefit compared to the other projects that would have facilitated similar levels of capacity.
- We have worked in close collaboration with SSEN Transmission to complete detailed analysis for the Initial Needs Cases on Argyll - Kintyre strategy and the Final Need Cases for Isle of Skye. Both projects deal with replacement and upgrade of old network; the need to develop a cost-effective solution for asset upgrades; investment in capacity to allow for future expected renewable growth, against a background of some of the most challenging terrain in GB. The potential value expected from the project is **£18m**.
- For SP Transmission, we have worked closely on the key part of the network in Dumfries and Galloway to understand the needs for transmission reinforcements to enable the connection of the next generation of onshore wind. Across the board, our independent assessment provides the TOs and Ofgem with clear evidence of the relative benefits of each proposed option against the future scenarios evidenced in the FES. Together our analysis points to the optimal investment decisions which deliver the best return for consumers over the lifetime of the project and demonstrate that billions of pounds of investments are being well targeted and returning value for money for consumers.
- The CBA for the combined initial and final needs case (INC and FNC) Large Onshore Transmission Investments (LOTI) submission of the uprating of the Hackney, Tottenham and Waltham Cross 275 kV line to 400 kV (HWUP) was completed by the ESO for NGET in August 2022. This scheme is crucial to allow extra flow through London to the South Coast interconnectors. The ESO assessed HWUP (as submitted to NOA7) as one of eight options (including "Do Nothing") within this LOTI. HWUP had the least worst regret out of all options by a significant margin, including the sensitivity analysis, and provides a potential benefit **£381m**. There are large delay costs if HWUP is not delivered on its Earliest In Service Date (EISD) of 2027.
- For NGET, we also considered nine options to improve the ability to transfer electricity through the East Anglia section of the network. It was found that the optimum option included the construction of a new overhead line connecting Norwich to Bramford, Bramford to Tilbury, and Tilbury to Grain, as well as an offshore HVDC Link from Richborough to Sizewell. The optimal solution identified within the CBA provides **£479m** of additional value compared to other options.

Consumer benefit of Commercial Solutions

Commercial solutions drive consumer value by providing an alternative to asset-based solutions. Currently, these take the form of commercial intertrips (where we form an agreement with generation plant to alter their output if required) but in the future, there may be additional forms. Commercial solutions can be implemented sooner than an asset can be delivered, meaning they can help address the growth in constraint cost in the short-term. It is however important to note that these solutions do not provide network resilience or help towards compliance with the SQSS. Use of commercial solutions should continue to be explored for a specific range of network conditions and locations because expanding their use into more areas of the network could erode the much-valued network resilience we currently have, resulting in consumers being worse off. Should system requirements change in the future, the commercial solutions can be adapted to address them.

We forecast that the consumer benefit of the commercial solutions in NOA is **5.81%** of the overall consumer benefit of the NOA 2021/22 Refresh[15] CBA. Due to the unique nature of the NOA Refresh, this consumer benefit is from the single scenario Leading the Way+ (LW+). Leading the Way+ is an adaptation of the FES Leading the Way scenario for use in the Holistic Network Design (HND) and NOA 2021/22 Refresh processes. The benefit was calculated using the 'Anti-regret' method but has been adjusted to options post-2030 only. This differs from historic NOAs and is the driver for the slightly reduced consumer benefit seen here compared to NOA 2021/22's benefit of 6.5%.

Potential benefit of acceleration of delivery of options

The NOA Refresh also provides recommendations for acceleration of some projects to a 2030 delivery. Acceleration in the context of this report refers to the NOA Refresh recommending specific options that were submitted with an EISD later than 2030 to be delivered on a required in-service date (RISD) of 2030. We have calculated the potential constraint cost savings if this recommended acceleration is completed to be £1214m. This was calculated by comparing the constraint cost of delivering these options in 2030 and their EISD.

Consumer benefit from ad-hoc cost benefit analysis (CBAs)

Summary of results

In the past 6 months, we conducted two ad-hoc CBAs, one of which has concluded. By carrying out these assessments on behalf of the TOs and other industry members, the ESO aims to recommend options which are in the best interest of consumers. We estimate that the recommendations we have made across these projects have the potential to save consumers approximately **£588m**.

Below are the estimated consumer benefits from the ad-hoc cost benefit analysis we have conducted over the last six months. These have been calculated using the method detailed above.

Ad-hoc CBA	Estimated Consumer Benefit (£m)
Bramford SGT upgrade CBA	588
Total	588

[15] The NOA 2021/22 Refresh replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND).

RRE 3C Diversity of Technologies Considered in NOA

April - September 2022-23 Performance

This Regularly Reported Evidence details the number and type of different solutions considered each year through the NOA and any NOA pathfinder tenders, as well as the ESO's explanations of action taken to increase the pool of solutions. Should include number of parties that:

i. Express interest
ii. Are participants within NOA / NOA pathfinder tenders
iii. Are successful / receive contracts

Numbers for NOA and NOA pathfinders are reported separately for transparency.

a) Solutions considered in NOA 2021/22 Refresh

The expression of interest process does not apply to the NOA so here we report on solutions submitted by participants.

The NOA 2021/22 Refresh replaces the previously published NOA 2021/22 and incorporates the recommended offshore network design set out in the Holistic Network Design (HND). The table below shows the number of options submitted by participants in the NOA 2021-22 Refresh, and of those, how many are new to the NOA this year. The new options are submitted by TOs, with the ESO providing the future requirements of the network based on our FES projections and working closely with the TOs to ensure that appropriate solutions are submitted into the NOA process. The NOA 2021-22 Refresh did not assess options that were found to be optimal pre-2030 as they inherited their recommendation from NOA 2021/22 or options that were classes as 'HND essential' through the connections' assessment process of the Holistic Network Design (HND).

Table 22: Options submitted by participants in NOA 2021-22 Refresh

Technology Main Category	**Total Number** Submitted in NOA 21/22 Refresh	**New options** Submitted in NOA 21/22 Refresh
Circuit	28	20
Route modification	-	-
Transformers	-	-
Substation & switching	-	-
Flexible AC transmission system (FACTS)	1	1
New technology	-	-
Total asset-based solutions	**29**	**21**
Commercial solutions	8	-

b) NOA Pathfinders

Supporting Information

More detailed information on the NOA Stability, Voltage and Constraints pathfinder can be found in the Pathfinder section of RRE 3A.

Notable events during September 2022

Regional insights from the Future Energy Scenarios published

'Regional Insights from FES 2022' is a brand-new document summarising the key insights from this year's FES publication from a regional perspective. It also provides further information about where you can find more detailed regional data and our next steps in regionalising our scenarios further.

We want to use this document to continue the debate on regional energy, ensuring that our stakeholders have the opportunity to input into our assumptions as we further develop our regional modelling capability.

We intend for our modelling and insights to provide better information for policy and whole system investment decisions as well being able to anticipate regional operability issues on the networks with enhanced regional data providing greater support for conversations with industry stakeholders.
You can download 'Regional Insights from the FES' and access further information here.

We notified Stability Phase 3 tender bidders of their individual outcomes

Stability Phase 3 Pathfinder sought solutions to help manage short circuit level and inertia in five regions across England and Wales from April 2025. The tender assessment has now concluded and on 27th September all bidders were informed of their individual outcomes. The results will remain confidential until all contracts have been fully signed, after which the results will be shared with wider industry.

The Stability Phase 3 tender is a culmination of two years of technical analysis, service design, tender management and stakeholder engagement to increase the stability of the network while allowing more renewable energy to be generated. It builds on previous Stability Pathfinders (Phase 1 and Phase 2), some of which are now in service.

DER webinar for the RDP MW Dispatch project

As part of Regional Development Programme 1 (RDP1), the roll-out of the MW Dispatch service with National Grid Electricity Distribution (NGED), both parties held a progress update webinar with Distributed Energy Resources (DER) on 27th September. This webinar followed previous session held in July & November 2021 and provided customers with an overview of project progress, updates to the service design and next steps for commencing onboarding of the new Transmission Constraint Management service.

During 2022, the project team across both the ESO and NGED have been building on previous stakeholder feedback, refining and implementing the end-to-end system updates, tools and processes in preparation for the project's first external release. The webinar shared the outcomes of this work whilst also focusing on the key next steps required to test and fully implement the new functionality. Onboarding will be enabled via the ESO's Single Market Platform, and the project team expect to open this process to DER in late November. In the run-up to this first go-live, we will be providing regular updates to customers, along with demonstrations and FAQ information on the ESO's website.

Plan delivery

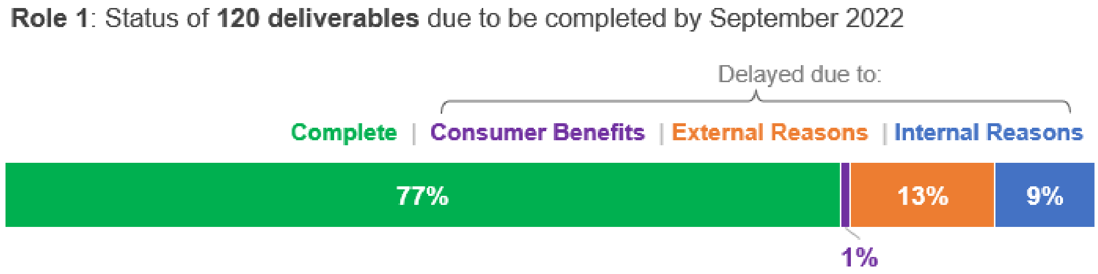
Our RIIO-2 deliverables tracker which we publish on our website provides a full breakdown of the status of our deliverables, with commentary including explanations for all delayed milestones.

Role 1 - Progress of our deliverables

For Role 1 (Control Centre Operations), the Delivery Schedule lists 44 deliverables in total, which is made up of **198** milestones.

- **120** of these milestones were due to be completed by September 2022
- **92** (77%) of those are now complete
- **28** (23%) of those are not complete which break down as follows:
    - **1** (1%) is delayed in order to deliver an improved outcome for consumers
    - **17** (13%) are delayed due to reasons outside the ESO's control
    - **10** (9%) are delayed due to ESO related delays

These results are illustrated below:

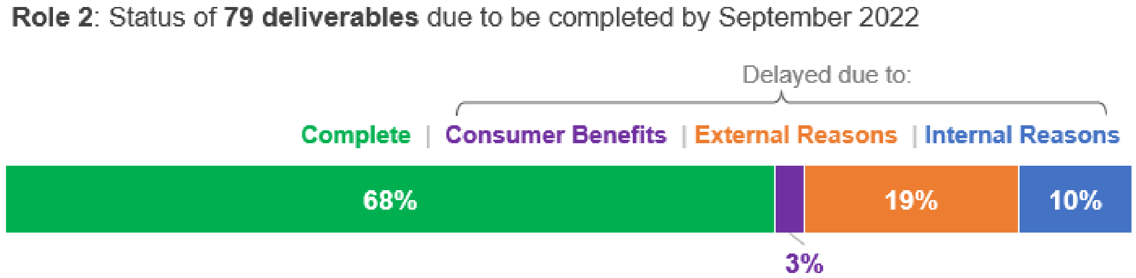


Role 2 - Progress of our deliverables

For Role 2 (Market development and transactions), the Delivery Schedule lists 25 deliverables in total, which is made up of **108** milestones.

- **79** of these milestones were due to be completed by September 2022
- **54** (68%) of those are now complete
- **25** (32%) of those are not complete which break down as follows:
    - **2** (3%) are delayed in order to deliver an improved outcome for consumers
    - **15** (19%) are delayed due to reasons outside of ESO control
    - **8** (10%) are delayed due to ESO related delays

These results are illustrated below:

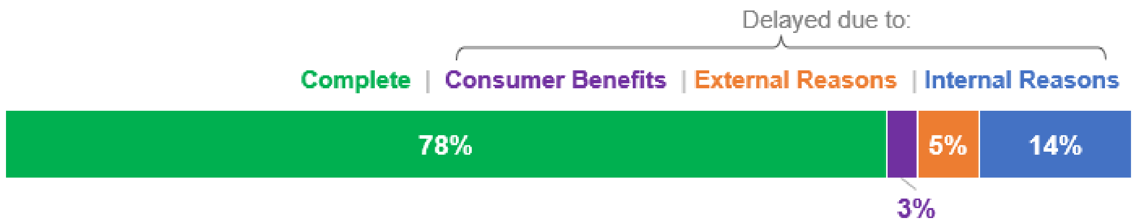


Role 3 - Progress of our deliverables

For Role 3 (System insight, planning and network development), the Delivery Schedule lists 48 deliverables in total, which is made up of **234** milestones.

- **147** of these milestones were due to be completed by September 2022 (3 are no longer valid).
- **114** (78%) of those are now complete
- **33** (22%) of those are not complete which break down as follows:
    - **4** (3%) are delayed in order to deliver an improved outcome for consumers
    - **8** (5%) are delayed due to reasons outside of ESO control
    - **21** (14%) are delayed due to ESO related delays

Role 3: Status of **147 deliverables** due to be completed by September 2022



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.

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 and provision of data and forecasting. The ESO's recent activity in this area includes awarding contracts for restoration and progressing the Distributed ReStart project, as well as ongoing activities such as demand forecasting, energy trading, real-time operation of the electricity transmission network, and providing transparency of the ESO's activities via the Data Portal and weekly Operational Transparency Forum webinars. Overall, from your experience in these areas over the last 6 months, how would you rate their performance?"

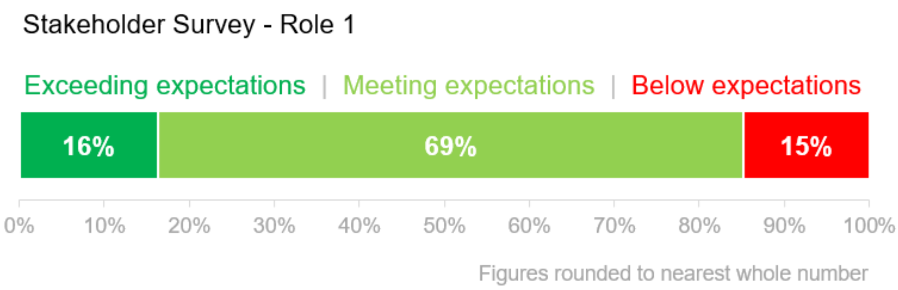
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- 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 **332** stakeholders, and received **61** responses to this question, which were distributed as follows:

- **16%** exceeding expectations
- **69%** meeting expectations
- **15%** below expectations

  (Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 1
"Exceeding Expectations" **Ten** stakeholders scored us as "Exceeding expectations". They were asked what the ESO did that exceeded their expectations.	• Communication was the biggest reason given by stakeholders as to why ESO was exceeding expectations. This combined with excellent engagement, collaboration and being informative meant the feeling across these stakeholders was ESO had a good working relationship with external industry partners.
"Meeting Expectations" **42** stakeholders scored us as "meeting expectations". They were asked what it would take for the ESO to be exceeding expectations for them.	• The two main themes were firstly, stakeholders who said the ESO would need to improve communication and engagement to exceed expectations, with restoration and strategic planning mentioned, and a need for more regular dialogue with industry. Secondly, several stakeholders reiterated that they were satisfied with the ESO's performance for Role 1. • Some stakeholders said that they would like to have seen more insight and analysis in the Winter Outlook report, and some would like to see more action and communication on Restoration. • Other stakeholders said they wanted to see: more innovation, better sharing of data/information, reduction in balancing costs, more progress on strategic planning, better use of small assets
"Below Expectations" **Nine** stakeholders scored us as "below expectations". They were then asked the ESO needed to do to meet their expectations.	• Stakeholders would like to see improvements to certain processes to deliver quicker decisions and also give industry sufficient notice to prepare for changes. • On engagement, stakeholders would like a more collaborative approach and more engagement in some areas. • In terms of information that the ESO provides to the market, stakeholders would like us to act on suggestions from industry, and provide more clarity on some of the information we publish.

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, Electricity Market Reform and Industry Codes and Charging. The ESO's recent activity in this area includes hosting workshops for Net Zero market reform, reserve reform and running a Capacity Market launch event and second Markets Forum. Furthermore, the ESO has implemented Frequency Risk and Control report (FRCR) phase 1, launched the Day Ahead Short Term Operating Reserve (STOR) product, published its Code Administrator annual report and provided details of code deliverables for the upcoming year. Overall, from your experience in these areas over the last 6 months, how would you rate their performance?"

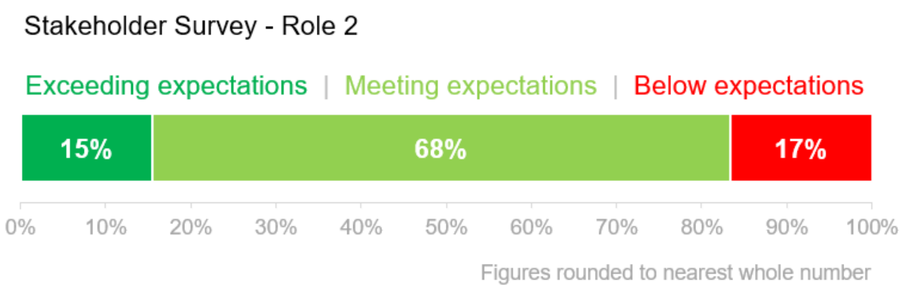
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- 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 **532** stakeholders, and received **84** responses to this question, which were distributed as follows:

- **15%** exceeding expectations
- **68%** meeting expectations
- **17%** 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.	• Several stakeholders commented that they believe the ESO are doing a good job in creating a new service for the market. Market reform had clear direction and major innovation. • Some pointed out that the quality of the reports and analysis were very high, with lots of detail and high-quality data. • Stakeholders felt that the scale of work had been handled confidently, prioritising the correct tasks, and that the ESO had engaged actively with industry and with the complexity of the subject at hand.
"Meeting Expectations" **57** stakeholders scored us as "meeting expectations". They were asked what it would take for the ESO to be exceeding expectations for them.	• General feeling from stakeholders is more proactive engagement is needed with the industry i.e. suppliers. This is linked to a common theme of a lack of speed on ESO's part, meaning projects and time frames were not met, mainly in relation to getting new renewables online. • Honesty and transparency are other areas where stakeholders felt improvements could be made. Explaining why changes are necessary would also help towards better communication. • Lack of vision and not thinking of the wider picture when it comes to costs are other topics brought out in the feedback. • A lot of comments referred to the fact that stakeholders were satisfied with everything and didn't have anything of note to mention that would have caused them to say expectations were exceeded.

"Below Expectations" **14** stakeholders scored us as "below expectations". They were then asked the ESO needed to do to meet their expectations.	• An overarching theme was a lack of speed from ESO. Stakeholders felt the ESO was slow to make decisions and lack of clear time frames combined with low industry expertise and slow engagement have made up most of the stakeholder views. • A couple of comments singled out the work on Locational Marginal Pricing (LMP) as a reason for scoring the ESO as being below expectations. • Other topics mentioned were lack of improvement in industry codes performance; questions on market design and development not being addressed; issues with the capacity reform portal; and the ESO website.

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, Strategy and Insight and long-term Network Planning. The ESO's recent activity in this area includes progress on the Stability Pathfinder projects, publishing a report to set out how it will address increasing constraint costs, consulting on enabling the DSO transition, submitting the Early Competition plan to Ofgem, working with stakeholders including BEIS and Ofgem to progress its Offshore Coordination work, publishing the winter review and consultation, engaging on new Regional FES program and delivering the Future Energy Scenarios for 2021.Overall, from your experience in these areas over the last 6 months, how would you rate their performance?

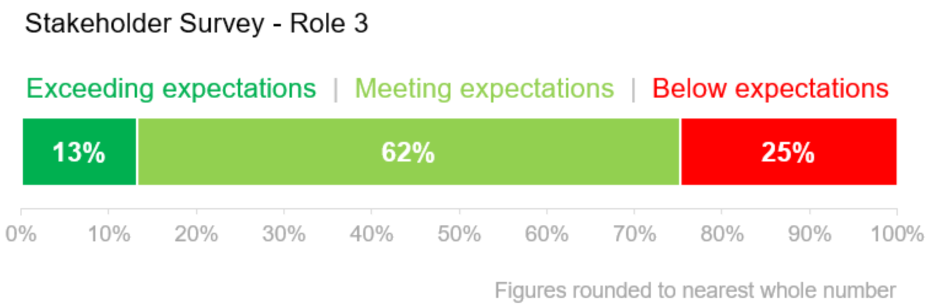
Survey participants were given the options of rating the ESO's performance for each role as below expectations, meeting expectations, or exceeding expectations.

- 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 **634** stakeholders, and received **113** responses to this question, which were distributed as follows:

- **13%** exceeding expectations
- **62%** meeting expectations
- **25%** below expectations

(Percentages rounded to the nearest whole number)



	Summary of stakeholder feedback for Role 3
"Exceeding Expectations" **15** stakeholders scored us as "Exceeding expectations". They were asked what the ESO did that exceeded their expectations.	• The main theme was clear, good quality communication. This ranged from clear simple messages to interactions with knowledgeable ESO employees. • The Open Innovation event held in 2022 was mentioned several times. It was highly praised for how well it was run, usefulness to all parties and how it will support the development of important projects. • Other reasons given as to why expectations were exceeded are; delivery of HND, and ESO's pragmatic approach to projects.
"Meeting Expectations" **70** stakeholders scored us as "meeting expectations". They were asked what it would take for the ESO to be exceeding expectations for them.	• Stakeholders felt that the ESO should be more flexible and more open to change in terms of exploring new approaches and adopting new methods. • They felt that ESO should work to improve its existing everyday processes e.g. Connections. Engagement and timings need to be looked at. • Several stakeholders referred to the Holistic Network Design (HND) as a source of why they feel we are not exceeding expectations. They stated that tight deadlines were very challenging for ESO and the industry. • Timing was highlighted by a few stakeholders and the need to get things turned around quicker. • Other topics in the comments were; the need for more follow up meetings, more proactive in network changes, and delivering quicker solutions.
"Below Expectations" **28** stakeholders scored us as "below expectations". They were then asked the ESO needed to do to meet their expectations.	• Limited number of internal interactions and coordination combined with a lack of communication make up most of the comments raised from stakeholders. • Several comments referenced a need for the ESO to be much more transparent, and to not just ask customers for feedback but also to act on it. • It was highlighted by several stakeholders that they feel engagement has been lacking and not up to standard, especially among comments from generators. • Stakeholders felt there was too much focus on non-material items, too much use of jargon and lack of direction resulting in some unfortunate positioning by the ESO. • Speed of new connections was also a theme with it taking too long to set up and time frames too far in the future.

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. Final outturn costs were submitted for the 2021/22 reporting period in the RRP submitted to Ofgem in July 2022. The final cost outturn for the BP1 period will be submitted in the next RRP cycle in July 2023.

The reported spend to date for the 2022/23 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 ESO's cost benchmark of £506.0m has not changed since the prior cost assessment published in April 2022.

The following table sets out our spend to date and forecast for the RIIO-2 BP1 period, compared to the cost benchmark.

		Role 1	Role 2	Role 3	**Total**
Cost benchmark	(£m)	208	159	139	**506**
Spend to date (up to end of September 2022)	(£m)	159	105	87	**351**
Forecast spend for remainder of BP1	(£m)	77	50	42	**169**
Forecast total spend for BP1	(£m)	236	155	129	**520**
Forecast deviation from cost benchmark	(£m)	28	-4	-11	**13**
Forecast deviation from cost benchmark		**13%**	**-2%**	**-8%**	**3%**

*The figures in this table are made up of both **directly** and **indirectly attributable** costs.*
See 'Cost Benchmark Summary' table on page 77 for full breakdown of costs.

Since our April 2022 cost assessment forecast, we have updated the outturn for the 2021/22 reporting year based on the numbers in our July 2022 RRP report. The base numbers for our 2022/23 cost assessment forecast are from our recent RIIO-2 BP2 submission, with an update to reflect the latest view of direct IT investments. Our 2022/23 forecasts have also now been converted to 18/19 prices using the latest published Ofgem indexation rates.

Overall forecast costs for the BP1 period have decreased by £28.2m since the April 2022 submission, with the key driver being an updated view of direct IT investments. Our BP2 plan included £10.3m of this forecast reduction. There is a further £12.6m decrease as a result of real price reductions given increased inflation rates since the BP2 submission[16]. The remaining decrease is driven by an update to IT investments (-£6.2m), partly offset by a true up of 2021/22 costs (+£0.9m) following the July 2022 RRP submission.

As our BP2 submission has an extensive narrative on the scope, milestones, cost drivers and cost variances for our IT investment, our narrative will focus on the changes we have made since the BP2 submission.

[16] 2022/23 forecast costs for October cost assessment deflated to 18/19 prices using latest Ofgem published inflation indices as per the Dry Run 2 PCFM

Directly attributable costs - by role

Please note that indirectly attributable costs are summarised on page 74.

Role 1 (Control centre operations) direct expenditure

For Role 1, we are currently forecasting to spend £32.6m (23.8%) more than the cost benchmark over the BP1 period for directly attributable costs.

Role 1	Activity	Variance £m
	Balancing Programme*	36
	Other	(3)
	Total	**33**

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

Whilst there are smaller variances to benchmark across all Role 1 direct IT investments the key driver of the additional spend is the Balancing Programme. The Balancing Programme forecast spend for the BP1 period is £63.8m, which is £8.4m lower than reported in our BP2 submission. Details of the cost change variance to the BP1 benchmark for the investments that make up the Balancing Programme, can be found in BP2 Annex 4 – Digital, Data and Technology.

Balancing Programme (+£35.8m)

Cost benchmark for BP1	£28.1m
Forecast expenditure over BP1	£63.8m
Variance	**£35.8m**
Forecast per BP2 submission	£72.2m
Increase/(decrease) since BP2	**£(8.4)m**

Drivers of change since BP2 submission	The majority, £4m is due to deferral of CNI data centre hardware spend into 2023/24, as the specification required for the order to be placed is not expected until next year. A further £2m is due to reduced spend on the Modern Dispatch Optimiser in 2022/23 and there is also a £2m reduction due the transformation of ASDP, rather than migration. However, these decreases are expected to offset by increased spend during the BP2 period.

Role 2 (Market development and transactions) direct expenditure

For Role 2, we are currently forecasting to spend £1.5m (1.7%) more than the cost benchmark over the BP1 period for directly attributable costs.

Role 2	Activity	Variance £m
	Settlements, Charging and Billing*	10
	EMR Portal Improvements	8
	Role in Europe	(13)
	Other	(3)
	Total	**2**

** Includes investments: (290) Charging and billing asset health, (300) Charging regime and CUSC changes, (410) Ancillary services settlements refresh, (610) Settlements, charging and billing*

The increased spend against benchmark is due to two main factors: EMR Portal improvements (+£7.8m), and Settlements, Charging and Billing (+£10.1m). These increases are partly offset by Role in Europe (formerly EU regulation) (-£13.1m).

The cost variances to benchmark for the Settlements, Charging and Billing, EMR portal improvements and EU regulatory changes have not changed significantly since our BP2 submission and details of the cost change variance to the BP1 benchmark can be found in BP2 Annex 4 – Digital, Data and Technology.

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

For Role 3, we are currently forecasting to spend £5.5m (8.0%) less than the cost benchmark over the BP1 period for directly attributable costs.

Role 3	Activity	Variance £m
	Offshore Co-ordination	5
	Early Competition	4
	Enhanced Frequency Control	(9)
	NOA enhancements	(5)
	Other	(1)
	Total	(**6**)

The net reduction in cost compared to benchmark is due to the following main factors: Offshore Coordination (+£5.4m) and Early Competition (+£4.1m), offset by Enhanced frequency Control (formerly Zero Carbon Operability) (-£9.2m) and NOA Enhancements (-£5.3m).

There are no material changes in the cost variances compared to our BP2 submission. Details of our costs for new roles in Offshore Co-ordination and Early Competition can be found in BP2 Annex 1 – Supporting Information. Further details on Role 3 investments can be found in BP2 Annex 4 – Digital, Data and Technology.

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 benchmark is given below.

	Activity	BP1 cost Benchmark £m	BP1 Forecast £m	Variance £m	Variance %
	ESO Supporting Opex	15	14	(1)	(8)
	Capex	43	34	(9)	(22)
	Total Business Support	126	124	(2)	(2)
Business Support sub-categories	IT & telecoms	94	84	(10)	(7)
	Property management	11	11	0	0
	HR & non-operational training	5	6	1	20
	Finance, audit & regulation	6	9	3	50
	Insurance	2	1	(1)	(50)
	Procurement	1	1	0	0
	CEO & group management	7	12	5	71
	Other Price Control Costs	28	25	(3)	(10)
	Total	**212**	**197**	**(15)**	**(7)**

Overall, our forecast indirectly attributable costs are 7.2% lower than benchmark.

Our ESO opex costs relate to ESO's Business Change, Innovation, Assurance, Regulation and Customer teams. These costs are in line with benchmark.

Indirectly attributable capex costs relate to Business Services systems, Hosting, IT Operations and Tooling, Enterprise Data Networks and End User Computing as well as spend on Property. Spend on Business Services systems is broadly in line with benchmark with higher spend on our ERP system being offset by lower spend on smaller IT systems. The lower forecast cost compared to benchmark is largely driven by lower investment in Hosting and Enterprise Data Networks.

Business Support costs are overall in line with benchmark with lower IT spend being offset by a higher than forecast allocation of corporate centre costs.

Other price control costs mainly relate to cyber security costs and are £2.5m lower than benchmark.

Amber projects (All Roles)

Ofgem's ESORI guidance also defines 4 specific IT projects for which additional reporting on delivery and latest costs forecast is required. These are high-value projects which Ofgem will track more closely due to the uncertainty of scope at the time of Final Determinations. This follows on from Ofgem's assessment of ESO's IT projects, which is set out in Appendix 4 of Final Determinations[17].

These projects are:

1. 110 - Network Control
2. 180 - Enhanced Balancing Capability
3. 220 - Data and Analytics Platform
4. 500 - Zero Carbon Operability

1. 110 - Network Control

110 Network Control is delivering two primary projects: the Integrated Energy Management System (IEMS) Life Extension project and the Network Control Strategy project. The former will maintain the service life of the existing IEMS platform, the latter will develop the strategic replacement to IEMS. This will incorporate new Situational Awareness functionality and separate Transmission and System Operator features.

Investment forecast status:	Higher than cost benchmark

We are **£2.8m** above our investment benchmark of **£9.0m** for BP1 (£8.1m capex, £0.9m opex). Our forecast has not changed materially since our BP2 submission and commentary on cost variances can be found in Annex 4 – Digital, Data and Technology.

This supports the delivery of the following overarching milestones:

Role 1	A1.3	Transform Network Control	D1.3.1, D1.3.2, D1.3.3
	A2.3	Training simulation and technology	D2.3.1
Role 2	A4.3	Deliver a single day-ahead response and reserve market	D4.3.3

2. Future balancing (180 - Enhanced Balancing Capability)

This investment delivers a new balancing platform to enable Electricity National Control Centre (ENCC) engineers to perform the balancing actions needed to operate a zero carbon system.

Investment forecast status:	Higher than cost benchmark

Our current investment forecast for BP1 is **£40.3m** which is higher than the Final Determinations position of **£20.3m**. Commentary is provided above, under Role 1 and further in our BP2 Annex 4 – Digital, Data and Technology.

This supports the delivery of the following milestone:

Role 1	A1.2	Enhanced Balancing Capability	D1.2.1

3. 220 - Data and Analytics Platform

220 Data and Analytics Platform is foundational work to unlock the value of the data we hold. It will be the key technology underpinning all our internal and external data management, pulling together data from a variety of sources and ensuring there is only one source of the truth. This includes critical national infrastructure (CNI) and non-CNI data and analytics platforms as well as their associated integration platforms.

[17] https://www.ofgem.gov.uk/system/files/docs/2021/02/final_determinations_-_eso_annex_revised.pdf

Investment forecast status:	Lower than cost benchmark

Our current forecast is **£9.8m** which is **£1.3m** lower than the investment benchmark of **£11.1m** for BP1 (£8.9m capex, £2.2m opex). Further details on cost variances can be found in our BP2 Annex 4 – Digital, Data and Technology.

This supports the delivery of the following overarching milestones:

Role 1	A1.3	Transform Network Control	D1.3.1, D1.3.3
	A1.4	Control Centre Architecture	D1.4.1
	A17	Transparency and Open Data	D17.1, D17.2
Role 2	A5.3	Improve our security of supply modelling capability	D5.3
Role 3	A11.1	Refresh and integrate economic assessment tools to support future network modelling needs	D11.1
	A11.2	Implement probabilistic modelling	D11.2
	A11.3	Build voltage assessment techniques into an optimisation tool	D11.3
	A11.4	Build stability assessment techniques into an optimisation tool	D11.4
	A13.1	Carry out analysis and scenario modelling on future energy demand & supply	D13.1
	A13.2	Conduct mathematical and modelling and market research on local and wider geographic demand information	D13.2
	A13.5	FES: Integrating with other networks and supporting DNOs to develop their own DFES processes	D13.5.1, D13.5.2
	A15.6	Transform our capability in modelling and data management	D15.6.1, D15.6.2, D15.6.3, D15.6.4, D15.6.5, D15.6.7
	A16.3	Work more closely with DNOs and DER to facilitate network access	D16.3.4

4. 500 - Enhanced Frequency Control (formerly Zero Carbon Operability)

Consistent with our proposal in Final Determinations, project 500 Enhanced Frequency Control is delivering the monitoring and control system and services which will improve frequency stability, increase system reliability, and in turn lead to a reduction in the expenditure on managing frequency events. Phase 0, which is understanding the Zero Carbon Operability capability of the GB network, has commenced. This will determine the requirements, design and approach for Phase 1, which is a non-operational demonstration.

Investment forecast status:	Lower than cost benchmark

Our investment forecast for BP1 is **£1.0m** (totex) which is **£9.2m** below our investment benchmark of **£10.2m** for BP1 (£9.2m capex, £1.0m opex). The reduction is the result of delaying phases 2 and 3 into BP2. Further detail can be found in our BP2 Annex 4 – Digital, Data and Technology.

This supports the delivery of the following milestones:

Role 3	A15.7	Deliver an operable zero carbon system by 2025	D15.7.1

Cost Benchmark Summary

This information comes from Cost Benchmark Summary in the ESO Costs and Outputs Regulatory Reporting Pack (RRP)
All figures are in 2018/2019 prices

	Funding Category	BP1 Cost Benchmark £m	2021/22 Costs £m	Forecast 2022/23 Costs £m	Forecast Total £m	Higher / (Lower) £m	Variance % %
TOTAL	Total Role 1 Costs	**208.0**	**110.3**	**125.2**	**235.6**	**27.6**	**13.2%**
	Total Role 2 Costs	**158.6**	**72.3**	**82.8**	**155.1**	**(3.6)**	**(2.3%)**
	Total Role 3 Costs	**139.4**	**58.3**	**70.5**	**128.9**	**(10.6)**	**(7.6%)**
	Total Price Control Costs	**506.0**	**241.0**	**278.5**	**519.5**	**13.4**	**2.7%**
Role 1	ESO Opex	61.6	30.4	29.6	60.0	(1.7)	(2.7%)
	Capex	63.5	47.1	52.7	99.8	36.3	57.1%
	BSC	12.0	1.2	8.8	10.0	(2.0)	(16.5%)
	Total Directly Attributable to Role 1	**137.2**	**78.7**	**91.1**	**169.8**	**32.6**	23.8%
	ESO Opex	5.2	2.4	2.3	4.8	(0.4)	(7.8%)
	Capex	14.4	6.9	4.4	11.2	(3.1)	(21.8%)
	BSC	42.1	19.0	22.5	41.5	(0.6)	(1.5%)
	Other Price Control Costs	9.2	3.4	4.9	8.3	(0.9)	(10.2%)
	Total Indirectly Attributable to Role 1	**70.8**	**31.7**	**34.1**	**65.7**	**(5.1)**	(7.2%)
Role 2	ESO Opex	35.1	15.7	18.0	33.7	(1.4)	(3.9%)
	Capex	35.3	23.4	25.3	48.7	13.5	38.2%
	BSC	17.5	1.6	5.3	6.9	(10.6)	(60.5%)
	Total Directly Attributable to Role 2	**87.8**	**40.7**	**48.7**	**89.3**	**1.5**	1.7%
	ESO Opex	5.2	2.4	2.3	4.8	(0.4)	(7.8%)
	Capex	14.4	6.9	4.4	11.2	(3.1)	(21.8%)
	BSC	42.1	19.0	22.5	41.5	(0.6)	(1.5%)
	Other Price Control Costs	9.2	3.4	4.9	8.3	(0.9)	(10.2%)
	Total Indirectly Attributable to Role 2	**70.8**	**31.7**	**34.1**	**65.7**	**(5.1)**	(7.2%)
Role 3	ESO Opex	38.2	21.0	25.4	46.3	8.1	21.3%
	Capex	25.5	4.8	9.6	14.4	(11.2)	(43.7%)
	BSC	4.9	0.9	1.5	2.4	(2.5)	(50.7%)
	Total Directly Attributable to Role 3	**68.6**	**26.7**	**36.5**	**63.1**	**(5.5)**	(8.0%)
	ESO Opex	5.2	2.4	2.3	4.8	(0.4)	(7.8%)
	Capex	14.4	6.9	4.4	11.2	(3.1)	(21.8%)
	BSC	42.1	19.0	22.5	41.5	(0.6)	(1.5%)
	Other Price Control Costs	9.2	3.4	4.9	8.3	(0.9)	(10.2%)
	Total Indirectly Attributable to Role 3	**70.8**	**31.7**	**34.1**	**65.7**	**(5.1)**	(7.2%)